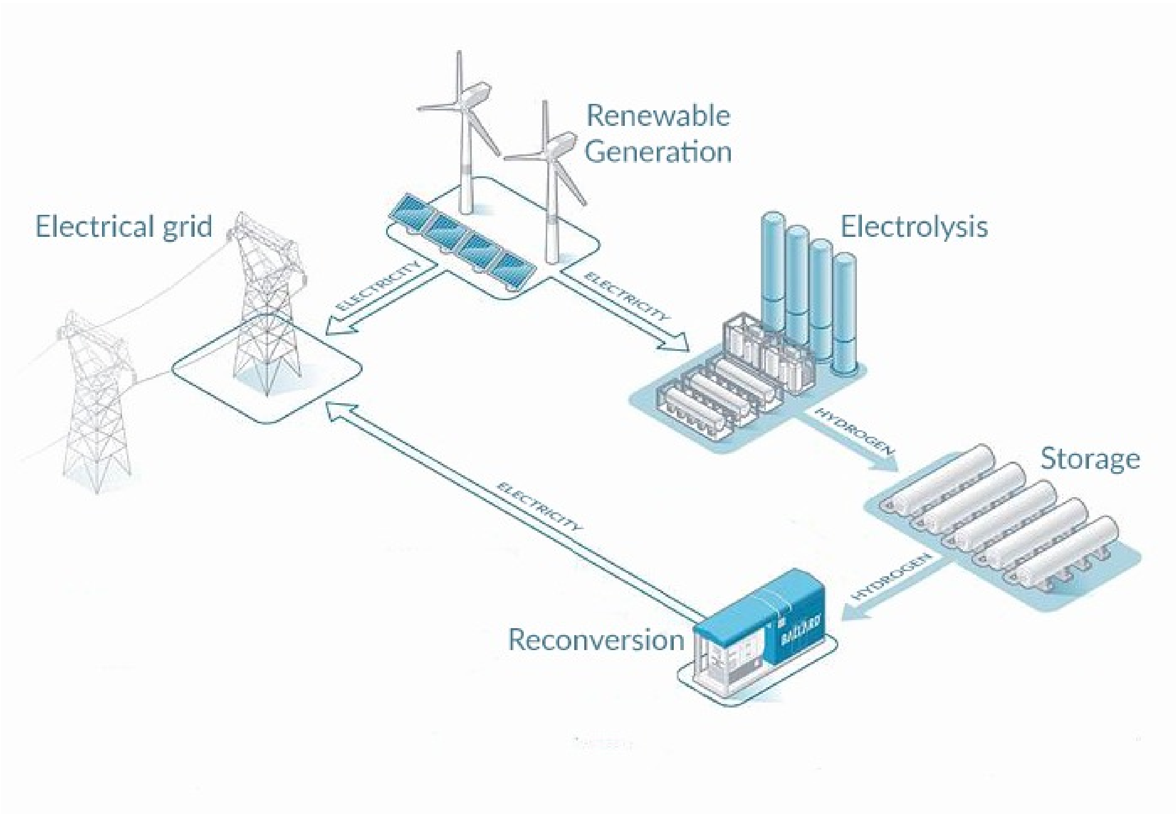
A TECHNO-ECONOMICAL ANALYSIS OF HYDROGEN AS LONG-TERM ENERGY STORAGE MEDIUM IN THE NETHERLANDS

How long-term hydrogen storage helps to achieve energy security in an energy system dominated by variable renewable energy sources



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Abstract

The integration of Variable Renewable Energy Sources (VRES) creates challenges for meeting load demand. The lack of on-demand power generation of these VRES effectively threatens energy security. Therefore, storage facilities, especially hydrogen, have been broadly researched for potential implementation in our energy system, enabling on-demand power "generation". This thesis adds to this research by providing a framework on how VRES and long-term storage technologies can be most optimally utilized to ensure weekly or monthly energy security. This framework is explicitly applied to the Netherlands and reviews the opportunities of a VRES dominated future energy system. The framework consists of a VRES generation model and load model and identifies the optimal load coverage using single- and multi-objective genetic algorithms. The VRES generation model is designed for a weekly and monthly timeframe by using 31 years of available weather data (1988-2018), specifically average wind speeds and solar irradiance, for a number of locations in the Netherlands. Using the available weather data, power generation per MW of onshore wind, offshore wind, and solar PV are calculated. Subsequently, this calculated VRES power generation is compared to available real-world VRES power generation data and a correction factor is determined. Applying the correction factor to the more extensive weather data set allows to effectively create a VRES power generation model, based on the weather circumstances as in these 31 years. Additionally, a weekly and monthly 31-year load profile is determined, using available data for load demand in the Netherlands. Thereafter, both a single and multi-objective algorithm is tasked to provide load coverage in two main scenarios at minimum cost. First, load coverage is achieved exclusively utilizing VRES capacity. Secondly, a variety of long-term storage facilities are introduced in combination with VRES capacity to acquire energy security. Furthermore, these two methods for achieving energy security are restricted in a number of sub-scenarios, which represent the societal preference restrictions regarding VRES installations.

Generally, energy security is most cost-effectively achieved utilizing long-term hydrogen storage facilities, as compared to an exclusive VRES approach. Specifically, alkaline electrolysis and hydrogen combined cycle gas turbines seem to be the most promising technologies to be applied for the hydrogen storage facility electrolysis and reconversion sub-steps respectively. Furthermore, societal preference has a significant effect on the total costs, increasing it considerably when offshore wind capacity is forcefully introduced in the VRES capacity mixture. Lastly, the timeframe considered for achieving energy security, either weekly or monthly, has a substantial effect on the total cost. The smaller weekly timeframe results in additional costs, as the long-term hydrogen storage facility, is utilized more broadly to meet load demand, increasing the capacity requirements for charging, discharging, and storage. Overall costs range between 139 and 211 billion Euros to achieve energy security using the more cost-effective long-term hydrogen storage approach, depending on the timeframe and societal constraints applied.

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1 Introduction

This chapter aims to provide a general overview of the thesis and its structure. Section 1.1 provides the motivation for this thesis. Section 1.2 provides an overview of the scope and goals. In section 1.3 the main questions answered in this thesis are discussed. Section 1.4 provides the methodology used to accomplish these conclusions. Finally, section 1.5 provides the outline for this thesis.

1.1 Motivation

The problems associated to climate change have led to a green push in the Dutch electrical grid, where Variable Renewable Energy Sources (VRES) will become an important source for electricity generation [1, 2]. With further goals set to eliminate carbon dioxide emissions and VRES being and becoming cost-competitive with fossil fuels, they are predicted to dominate electrical grids worldwide in the near future [1, 3, 4, 5]. However, a VRES dominated electrical grid experiences some issues, which require addressing before such an electrical grid can be achieved.

The leading problem regarding VRES, as the name suggests, is the variability of the power output, better known as intermittency [6]. Solar PV is a prime example, as this source exclusively provides power when solar radiation is present. Together with wind, which level of power output is also seasonally dependent, these VRES have become the lead technologies for renewable electricity generation worldwide [2]. VRES intermittency issues limit the applicability of the various technologies in the electrical grid. If these technologies penetrate the electricity supply to a too large extend, it can occur that during periods of wind and solar scarcity the load demand can not be met. In periods of wind and solar abundance, the exact opposite can occur, resulting in a net surplus of electricity. Electrical grids are rigid in their operation, allowing virtually no storage of energy in the network itself, resulting in issues caused by these mismatches [7, 8]. Even the current low capacity levels of VRES in the Dutch electrical grid cause these problems, which are currently resolved through power rerouting. Countries with higher VRES capacity levels, such as Germany, even have had some cases of power supply curtailment [9]. Power rerouting puts extra stress on the network and can thus be done only up to a certain limit, however, it is not problematic by definition. Power supply curtailment is problematic, as it results in power production losses, and thus decreased profits. With the future higher penetration of VRES in the Netherlands, as displayed in Figure 1.1, such mismatch events both will happen more often and become more severe, making curtailment likely a necessity also in the Netherlands [10]. Considering both the issues regarding shortage and excess, it must be concluded that with increased VRES capacity energy security in the Netherlands will be endangered.

To tackle both issues regarding scarcity and abundance, storage applications can be applied. Many different storage technologies have been suggested as a solution. Considering the seasonal dependence of electricity generation through VRES, long-term storage systems are required [12]. In practice, some storage facilities are already in use, where the most common and well-developed technique is pumped hydro storage [13]. The technique makes use of a reservoir created by a dam, which is filled artificially using excess electricity. However, this technique, although having huge potential worldwide, is highly regionally limited and no applications in the Netherlands exist [14]. Therefore, extensive research is being done on alternatives that can be applied anywhere, including the Netherlands, and focus predominantly on battery storage.

Various types of batteries are currently being used for energy storage, however, recently much research has focused on lithium-ion batteries. Lithium-ion batteries have shown a strong decrease in cost over the past years, and are prospected to further decrease in cost in the near future [15]. Furthermore, the technique has shown strong technological features, compared to

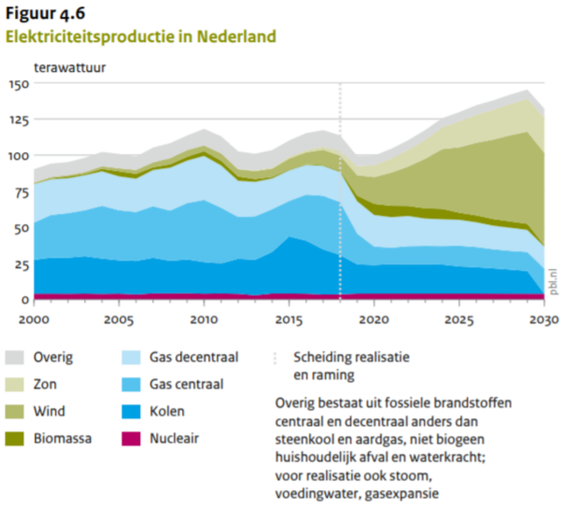


Figure 1.1: Current and Future Electricity Generation Mixture in the Netherlands, expressed in TWh [11]

previously used battery techniques, such as a higher energy density, stability, and increased amount of recharge cycles. Additionally, lithium-ion batteries have longer charge retention than other techniques, resulting in slower idle discharge rates [16]. These qualities show a promising future for the use of lithium-ion batteries as an energy storage medium, however, some limitations for long-term storage usage exist.

Various arguments can be made why battery storage, including lithium-ion, is not fit for long-term energy storage. Long-term energy storage facilities require significant storage capacity to transfer generated energy over a serious time frame. Even though costs for battery storage have been decreasing significantly, large-scale storage facilities, remain highly costly when battery technology is applied [17]. Furthermore, batteries are considerably less energy-dense than many other energy-carrying technologies, as is illustrated in Figure 1.2. Therefore, research suggests to use battery technologies as a short-term storage technology instead of applying it for long-term storage [18]. Short-term storage requires less storage capacity and usually has more charge and discharge cycles, suiting battery technologies much better [5].

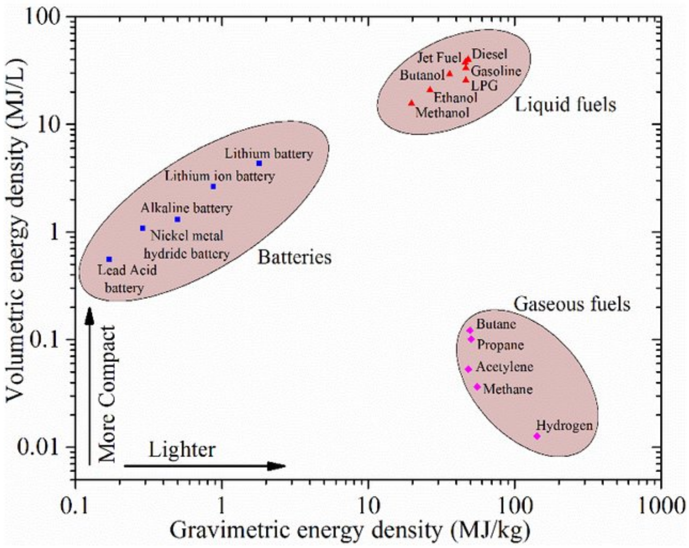


Figure 1.2: Energy Density of Various Storage Techniques, including Battery, Fossil Fuel and Hydrogen Technologies [19]

Further techniques for energy storage include methods such as molten salt, Compressed Air Energy Storage (CAES), Superconducting Magnetic Energy Storage (SMES), supercapacitors, and flywheels. However, each of these techniques experience, like battery storage, complications for long-term storage. Molten salt storage is heavily dependent on the presence of concentrated solar power plants, which are not fit for use in the Netherlands. CAES experiences low efficiency, due to the heating and cooling of air while being compressed and decompressed limiting the reconversion efficiency. Additionally, the energy density of compressed air energy storage systems is extremely low, thus reducing its effectiveness for large-scale long-term storage [20]. SMES has been predominantly mentioned for applications in short-term storage, due to the high cost associated with the technique [21]. An alternative for battery storage has been suggested in supercapacitors, however, this technology has been disregarded for long-term storage as its energy density is even lower than that of battery technology [22]. Lastly, flywheels are highly ineffective for long-term storage, as they have a high rate of self-discharging and high material costs for production [23].

Long-term electricity storage solutions are thus limited, however, hydrogen storage technology is considered a promising option, which is supported in a number of studies [18, 24, 25, 26, 27]. Hydrogen is deemed fit for long-term storage, as it has the highest energy storage density with regard to mass of the currently available techniques [26], as is portrayed in Figure 1.2, allowing for effective mass long-term storage. However, limited research on the economic cost of hydrogen long-term storage is available. Therefore, this research aims to provide a framework, which is based on data for the Netherlands, calculating the cost to achieve energy security using hydrogen technology for long-term storage in a VRES dominated electricity grid.

1.2 Scope and Goals

The scope of this thesis is to provide a comprehensive techno-economic review and optimal solution for the long-term energy intermittency complications of a VRES dominated electrical grid in the Netherlands. Specifically, hydrogen long-term energy storage is extensively reviewed to provide monthly and weekly energy security. This review contains current possibilities as well as developments for the future, building on the current literature and expanding it. Although the literature on hydrogen systems is quite extensive, it remains limited on long-term hydrogen storage systems for energy security purposes. Most available literature focuses on hydrogen as an end-product, which is considered the usable energy carrier. Therefore, the main focus in the literature is on hydrogen as an energy carrier, disregarding reconversion and applications in power supply. Nevertheless, long-term hydrogen storage is tackled by some papers, however, often being area-specific or much smaller sized and thus being largely not applicable to the situation in the Netherlands. Furthermore, the literature predominantly focuses on preemptively chosen pathways, therefore neglecting potentially more beneficial scenarios. Moreover, in the current rapidly developing field of hydrogen storage and reconversion, many technological developments and breakthroughs are achieved. Therefore, research quickly becomes dated as new methods should be incorporated and new optimal solutions are possible. Lastly, much of the available literature focuses on various specific subsystems of the long-term hydrogen storage system, rather than focusing on the whole system. This focus leads to highly specific research and conclusions on technologies, which might not be suitable in the larger scheme of a long-term hydrogen storage system.

To tackle these shortcomings in the literature this research will focus on four main points:

- Creating an overview of the technological systems available for long-term hydrogen storage, including closely linked methods to hydrogen storage, such as ammonia storage
- Creating a cost overview of the entire long-term hydrogen storage system, by performing a cost analysis of the various technological solutions within the system
- Creating a ready-to-use methodology applicable for calculating the costs for long-term hydrogen storage, providing an equal playing field to compare various techniques
- Providing a set of optimal pathways to achieve weekly and monthly energy security in the Netherlands

Using the overview of both the technological opportunities as well as their economic cost, a comprehensive analysis will be performed on long-term hydrogen storage in the Netherlands. This thesis will then conclude on the most cost-effective technologies for achieving energy security.

1.3 Research Questions

The scope of this research aims to answer the following research question:

"What are technologically and economically optimal pathways to provide energy security exclusively using variable renewable energy sources and long-term energy storage in the Netherlands?"

To find a comprehensive conclusion to the main research question the following series of sub-questions will be discussed and answered:

- **What are the available technologies and their properties, such as cost, efficiency, lifetime, and applicability in the Netherlands, for VRES and long-term energy storage systems?**

Many different technological solutions for long-term hydrogen or similar, storage systems exist. To create a comprehensive overview, the many options for the sub-parts of the hydrogen storage system are discussed. This sub-question helps to find a range of cost-effective potential pathways for long-term hydrogen storage.

- **What model can include the weather variability of weekly and monthly VRES electricity generation in the Netherlands?**

A model is designed, which includes the impact of weather variability on electricity generation from VRES in the Netherlands. The model treats the VRES capacity as a variable, allowing VRES capacity to be changed to find the optimal solution for a number of scenarios.

- **What are the required capacities and costs to achieve energy security exclusively using VRES?**

Potentially, weekly and monthly energy security can be achieved exclusively using VRES capacity. By reviewing this alternative it becomes clear whether long-term storage is a necessity.

- **What are the required capacities and costs to achieve energy security using VRES in combination with long-term hydrogen storage?**

The costs for a number of pathways for long-term hydrogen storage are analyzed, helping to conclude which technology is the most cost-effective for long-term hydrogen storage in the Netherlands.

- **How do societal preferences regarding VRES affect the results for achieving weekly and monthly energy security?**

Due to societal related constraints, the optimal solution is often not a possible or preferred solution. By analyzing societal preferences and incorporating these into the model, more realistic results, and thus costs, are determined.

- **How does the evaluated timeframe for energy security, weekly versus monthly, affect the results?**

Adjusting the evaluated timeframe can impact a variety of results, as the load demand and generation from VRES becomes more volatile as a smaller timeframe is considered. To review the effect of this volatility on long-term hydrogen storage both a weekly and monthly energy security timeframe are reviewed.

- **How do future developments, such as VRES cost, storage cost, electrolyzer cost/efficiency and load demand changes, affect the results?**

An emerging technology such as long-term hydrogen storage develops quickly. Therefore, a list of potential future developments is discussed and applied. Thereafter, the associated effects on the results are reviewed.

1.4 Methodology

First, this thesis performs a literature review, where technologies and costs associated with and similar to long-term hydrogen storage are discussed. Following the literature review, a number of pathways using the various researched technologies for the sub-parts of the long-term hydrogen storage system will be drafted. The most critical properties discussed in the literature review are cost and efficiency, as these will have a strong effect on the total cost.

Secondly, a model is devised, which incorporates the impact of weather variability on electricity generation from VRES in the Netherlands. This model is utilized to set up an accurate generation profile, which is variable depending on the VRES capacity. Additionally, a model for the load demand is created to generate an accurate load profile.

Thereafter, an optimization problem is designed, which is is tasked to cover the load profile using the VRES capacity variable generation profile at minimal cost. Two main scenarios are discussed, one including long-term hydrogen storage, one excluding the storage technology. When storage is available it can be used to redistribute electricity and thus storage capacity becomes an additional variable. Results from the optimization problem provide a cost overview for the various pathways set up based on the literature review. Furthermore, the optimization problem is adjusted in both main scenarios to represent weekly or monthly energy security.

Additionally, constraints are added to include societal preferences regarding VRES, helping to also find a more realistic solution. Lastly, the effect of an additional constraint regarding the restriction of inter-annual storage is analyzed for the long-term hydrogen storage optimization problem. In summary, many different optimization problems are constructed to represent various scenarios and constraints, helping to provide the best representation of a real-world application.

Finally, to solve the drafted optimization problems a black-box optimization is applied. To perform the black-box optimization both a Genetic Algorithm (GA) as well as a Multi-Objective Genetic Algorithm (MOGA) are used in the MATLAB environment. The GA is applied when a predetermined percentage of weekly or monthly energy security, i.e. %-load coverage, is discussed. The GA finds the capacities and cost of the VRES and the long-term hydrogen storage required to achieve that specific %-load coverage. The MOGA is applied to the optimization problem when the percentage energy security (%-load coverage) is kept variable and thus provides the optimal results for two objectives: cost and %-load coverage. The results from both GAs are ultimately used to answer the research questions.

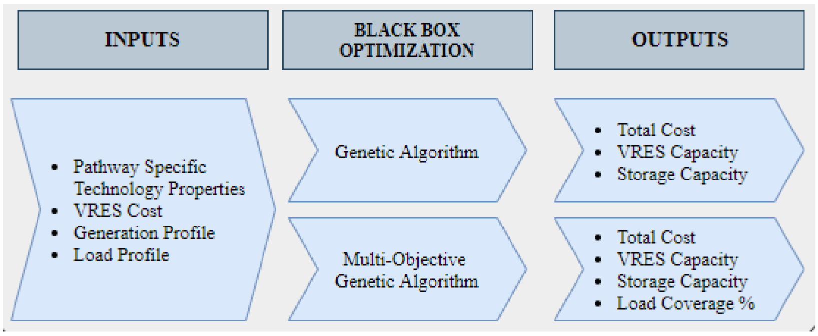


Figure 1.3: Overview of Research Approach

1.5 Thesis Outline

In this chapter, the general framework for this thesis has been outlined. In this section, the general thesis outline is discussed, shortly explaining the contents and goal of each chapter.

- **Chapter 2** focuses on the literature background of long-term hydrogen storage. Many technological solutions for the system, including some alternatives for hydrogen, and the necessary VRES are discussed. Most importantly, costs and efficiencies are debated, helping to create a useful overview. Moreover, it is discussed which techniques will be applied and which will be disregarded.

- **Chapter 3** presents the generation and load profile. The generation and load profile form the most important feed-ins for the optimization problem. It is discussed how weather data is combined with real-world VRES power production data to create a more elaborate data set. Furthermore, it is explained how available load demand data in the Netherlands can be used to also create a more elaborate usable data set.

- **Chapter 4** first introduces the optimization problem for providing weekly and monthly energy security exclusively using VRES. In total four scenarios per energy security time frame (weekly/monthly) are discussed. The three scenarios, apart from the fourth unconstrained optimization, are based on limitations for VRES capacity in the Netherlands.

- **Chapter 5** discusses achieving weekly and monthly energy security using VRES and long-term hydrogen storage. This chapter first introduces six potential technology pathways for long-term hydrogen storage. Subsequently, the optimization problem is introduced and solved for all pathways and the most cost-effective technologies are chosen. Thereafter, the previously introduced scenarios are applied and results gathered. Apart from applying these constraints, two additional scenarios are introduced wherein one inter-annual electricity distribution using the storage system is allowed, while this option is disregarded in the other scenario.

- **Chapter 6** provides insight into the effects of future developments on the results. Future changes to load demand, VRES cost, and electrolyzer cost/efficiency are discussed. Additionally, more in-depth insight into the storage level development is given.
- **Chapter 7** ultimately provides the conclusions to the research questions and discusses potential future work on the topic.

2 A Review of Long-Term Energy Storage Technologies

In this chapter the present literature on long-term energy storage systems is discussed. The literature was retrieved both through academic sources, as well as by consulting commercial parties. As was discussed in chapter 1.2 many technologies can be applied as energy storage medium, however, not all technologies are serious contenders for large-scale application. Therefore, this chapter also argues which technologies are not be considered for application in this research. This chapter summarizes some of the found costs, a more detailed discussion can be found in Appendix B.

Section 2.1 provides a general overview of the literature landscape with regard to long-term energy storage systems. Section 2.5 elaborates on VRES associated costs, focusing both on capital expenditures as well as operational expenditures. Section 2.2 introduces a number of methods for hydrogen production, where the predominant focus is on the various methods for electrolysis. Section 2.3 examines the many methods for hydrogen storage, while also shortly addressing ammonia storage as an alternative to long-term hydrogen storage. Section 2.4 reviews the options to reconvert hydrogen into electricity, addressing fuel cells and hydrogen fired gas turbines. Lastly, section 2.6 concludes on the most applicable storage technologies and creates an overview by drafting six potential pathways for long-term hydrogen storage.

2.1 Power to Gas to Power Technologies

Using a gas as an alternative carrier or storage medium for electricity is in the literature generally discussed as Power to Gas (PtG), this overarching terminology also includes power to hydrogen. PtG also describes the use of methanation processes, making a classic fossil fuel the end-product of the PtG technology [28, 29, 30]. This has some advantages, as methane can be used as a feed-in stock in gas turbines and heating for households, thus having direct applications in our current energy system. However, some drawbacks also exist, as the availability of a CO_2 source directly influences the possibility of the methanation process [29]. Furthermore, due to various process steps, the efficiency of the process is rather low, resulting in economic challenges [28].

A significant portion of the research regarding PtG uses hydrogen as an end-product, meaning no reconversion to electricity takes place. This has been liberally discussed by a number of authors in the literature [31, 26, 32, 33, 34, 35]. This research is more accurately described as Power to Hydrogen (PtH), which is mostly produced using electrolysis. Various types of electrolyzers exist and are discussed in the literature. For example Glenk and Reichelstein reviews the use of a solid oxide electrolyzer cell for the production of hydrogen, while Schiebahn et al. analyzes the use of polymer electron membrane electrolyzers [34, 31]. The various electrolyzers have their own advantages and disadvantages [35], which will be discussed in-depth in section 2.2.1. Michalski et al. note, similar to Glenk and Reichelstein and Salomone et al., the grid-balancing capabilities of hydrogen production, however, in most research the main focus remains on hydrogen as a feedstock. Most research agrees that hydrogen production through electrolysis experiences high costs compared to conventional methods, however, all predict decreasing costs in the future, due to the technological development of electrolysis [31, 26, 32, 33, 34].

An alternative for PtG technologies is the use of ammonia as an energy carrier and has been researched from a technological and economical viewpoint by a number of authors [36, 37, 38, 39, 40, 41]. Similar to PtG for methane production, the hydrogen, produced through electrolysis, can be further processed to ammonia. Ammonia is a much easier to use substance, as it becomes fluid at considerably higher temperatures than hydrogen, allowing for easier storage and transportation [38]. Therefore, ammonia is a much more accessible energy carrier and can currently be even more economical than hydrogen storage systems [36]. Furthermore, ammonia is currently a commonly used product in agriculture, however, current production methods are highly carbon dioxide intensive. Therefore, the produced ammonia can also be directly used as an end-product in these sectors, while decreasing greenhouse gas emissions significantly [37]. As for an energy storage medium, ammonia can be used in specific fuel cell systems to be reconverted to electricity [39]. Furthermore, some research has been done on the direct combustion of ammonia in gas turbines, as discussed by Rouwenhorst et al.. Ammonia seems very applicable in many scenarios, therefore, it might be an interesting substance for long-term storage. However, lower efficiencies can be expected due to the additional reform processes [40].

Up to now most discussed research deals with hydrogen, methane, and in some cases ammonia, as an end-product, however, research indicates the potential for electricity storage in these substances [42, 43, 36, 44, 45, 46]. These applications are becoming increasingly important, as the electricity demand is increasing and the aforementioned intermittency problems need handling [47]. Another VRES related problem is the maximum capacity of the electricity network. Welder et al. discuss the congestion due to wind farms in the electric transmission network in the North-West of Germany and how PtH and reconversion of hydrogen can provide a possible solution to these issues [42]. By transporting the electricity in the alternative form of hydrogen, the electricity network can be decongested at a lower cost than by expanding the network. Weidner et al. call the hydrogen storage for electricity supply a Power-to-Power application and discuss its applicability in Germany, Belgium, and Iceland. The hydrogen is produced from excess renewable energy, stored and, when needed, repowered and supplied to the grid through fuel cell systems. However, they conclude that in the short to medium term no profitable cases can be found for this application [43]. Further economic analysis was done for islanded renewable energy supply systems in combination with hydrogen and ammonia storage in 15 American cities by Palys and Daoutidis. Various technologies for hydrogen electrolysis and reconversion are considered, however, only a few storage techniques are discussed. In conclusion Palys and Daoutidis find that a mixture between ammonia and hydrogen storage provides the most cost-effective system [36]. A review on the applicability of reversible fuel cells in combination with hydrogen storage on a grid with dynamic electricity pricing schemes was performed by Mayyas et al.. The VRES penetration in the grid causes volatile prices, therefore potentially allowing for an economic margin if energy is stored during low prices and sold in periods of scarcity. Their research concluded that the levelized cost of storage was between 16.4 and 19.9 ¢/kWh. Apart from the economic analysis done by some papers, Steilen and Jörissen and Wolf discuss the more theoretical background of Power-to-Hydrogen-to-Power (PtHtP) applications. A variety of electrolysis, storage and reconversion methods are discussed in-depth, explaining technologies shortly mentioned in the rest of the literature. A bright future seems apparent for the use of hydrogen as a long-term energy storage medium for electricity supply. However, many uncertainties still exist, therefore, this thesis considers further research into the application of PtHtP essential.

To provide an elaborate overview of the PtHtP and PtGtP in general, the rest of this literature review analyzes each sub-part individually. Figure 2.1 shows a potential pathway for a long-term hydrogen storage system. Generally, this route is adhered to, although a power electronics subsection is added, to ensure a grid compatible system. Furthermore, alternatives to electrolysis and hydrogen as storage material are discussed.

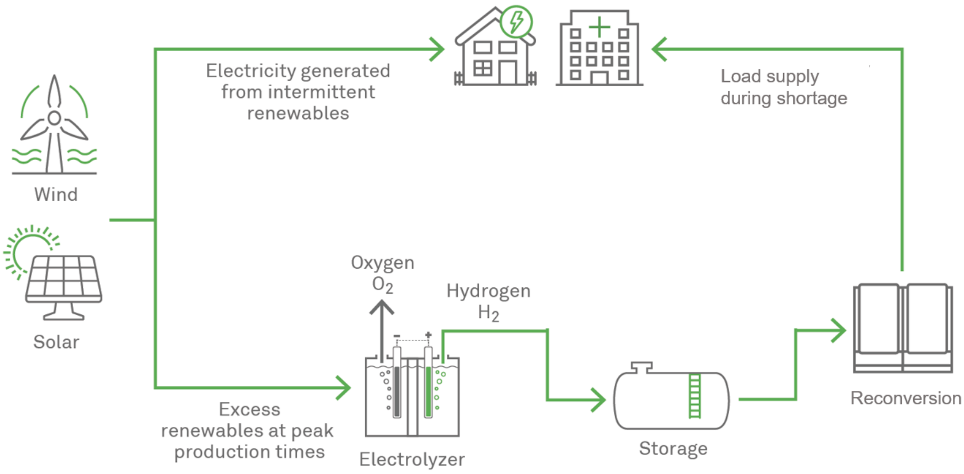


Figure 2.1: Simplified Overview of a Long-Term Hydrogen Storage System (adapted from [49])

2.2 Producing Hydrogen

Hydrogen is a widely used material in oil refinery, steel production, methanol production, and ammonia production [50]. Therefore, for the production of hydrogen, numerous methods exist, however, not all of them are cost-competitive. Therefore, virtually all hydrogen is produced using a single method, Steam Methane Reforming (SMR). With the call for less greenhouse gas-intensive methods of producing hydrogen, recently more research into electrolysis, thermolysis, and biomass gasification, has been done. The advances in electrolysis are discussed here, while the other old and newly developed techniques are shortly discussed and disregarded for long-term storage applications in appendix A.2.1, A.2.2 and A.2.3

2.2.1 Current State of Electrolysis

Future developments for hydrogen production focus on electrolysis using renewable electricity. By applying an electric potential to two electrodes, water can be split into hydrogen and oxygen. Hydrogen and oxygen each form at one of the electrodes, allowing for separation. To allow oxygen and hydrogen to be formed at the electrodes, the electrodes should be put in an electrolyte and be split by a diaphragm which allows ions to pass [51] [31]. Over the years various splitting techniques have been developed, these will now be shortly discussed.

Firstly, the most mature hydrogen production method is Alkaline ELectrolysis (AEL). This method has been available for several decades and has thus become a mature technology [52]. Nevertheless, some problems with the use of AEL do exist. The process is recognized to have slow ramp-up and downtimes. Furthermore, the technique is limited in a minimal part-load capability, as gas conductivity in the diaphragm can lead to critical hydrogen concentrations in the oxygen stream [31].

Secondly, recent research has strongly focused on Proton Exchange Membrane ELectrolysis (PEMEL). PEMEL differs from AEL in its use of a proton exchange membrane to separate the anode and cathode. The water is supplied at the anode side, where it splits into oxygen and hydrogen ions, which reconnect at the cathode to form hydrogen [35]. In comparison to AEL, PEMEL has some major advantages including no corrosive electrolyte, quick response time, more dynamical operation, higher hydrogen purity, and easier maintenance [35] [53]. For these reasons PEMEL has seen much research with regard to power-to-gas techniques and further development of the technique is expected. Nevertheless, AEL should not be disregarded as it is a highly mature technique. The various possibilities and limitations with regard to these two techniques are further displayed in the Table2.1.

Lastly, a more experimental technique, which has yet to see practical implementation, is the Solid Oxide Electrolyzer Cell (SOEC). In contrast to PEMEL and AEL, SOEC uses high-temperature electrolysis, typically at ranges between 700 and 900 degrees Celsius. This heat can be provided by a variety of sources and ensures a higher efficiency than AEL and PEM operations. However, the heat provides complications with regard to material stability. It is important to notice that SOEC is still in a pre-commercial developing phase, however, if development continues prices are expected to drop [35].
Rouwenhorst et al. have given an extensive overview of the advantages and disadvantages of AEL, PEMEL, and SOEC. This is overview is given in Table2.1, after adaptation from their paper.

Type	Advantages	Disadvantages
AEL	- Mature Technology [52] (Stacks in MW range available) - Long Lifetime [35, 31] - Low Cost [54, 55, 28] - Decent Efficiency [54, 55, 28] - Low Degradation (0.5-1%/year) [35]	- High Minimum Load Requirement [31] - Slow Dynamics [56] - Low Current Densities [35, 57]
PEMEL	- High Current Densities [57] - Fast Dynamics [56] - Low Minimum Load Requirement [57, 53] - Decent Efficiency [58, 59, 54, 28] - Low Degradation (0.5-2.5%/year) - Commercially Available [57, 35]	- Medium Cost [58, 59, 54, 28] - Use of Rare Earth Materials [60] - Only Smaller Stacks [39]
SOEC	- High Energy Efficiency [55] - Potential Low Cost Materials [61]	- High Cost [55, 30] - R&D Phase [55, 30] - High Temperature Operation [62] - High Degradation (3-50%/year) [35]

Table 2.1: Advantages and Disadvantages of the various Electrolysis Techniques

The various techniques differ quite severely, therefore making some more applicable in certain scenarios than in others. The various ad- and disadvantages should be inspected when determining a pathway for hydrogen production. For example, when peak shaving is desired for hydrogen production, the facility would need quick reaction times to the rapid grid changes. Therefore, both AEL and SOEC would not be very applicable, and thus PEMEL will be the preferred technique, even though this might induce higher costs. On the other hand, PEMEL might be less applicable for large-scale applications due to the use of rare earth materials. A rapidly expanding network of PEMEL might put the rare-earth material supply network under stress, increasing cost for the fabrication of the electrolyzers. Furthermore, degradation of the cell stack can play an important role in the preferred technology. There are many variables influencing the choice of the electrolyzer, as limitations for the various technologies exist. In designing a final system these limitations must be considered and taken into account.

Table2.2 provides an overview of the various costs and efficiencies of electrolysis reported in the literature. The costs portrayed are system costs, also including balancing of the plant. Note that limited information on SOEC is available, as the technique is still in a developmental phase.

Type	Efficiency (LHV, %)	CAPEX (€$_{2020}$/kW)	OPEX (€$_{2020}$/kW)	Source
AEL	67	933		[31]
AEL	77	1352		[28]
AEL	63-70	458-1245		[55]
AEL	65	772	2% of CAPEX	[63]
AEL	45-67	684-990		[54]
AEL	63-70	423-1183		[64]
AEL	66	1059-1588		[57]
AEL	51-60	823-1543	2-3% of CAPEX	[35]
PEMEL	77	1976		[28]
PEMEL	50-60	1008-1664		[55]
PEMEL	67	1865		[31]
PEMEL	65.9	812		[53]
PEMEL	57	1234	2% of CAPEX	[63]
PEMEL	45-71	1080-1746		[54]
PEMEL	56-60	929-1520		[64]
PEMEL	66	2012-2435		[57]
PEMEL	46-60	1440-2160	3-5% of CAPEX	[35]
SOEC	74	2205		[55]
SOEC	76-81	$\geq$ 2057		[35]

Table 2.2: Overview of the Costs and Efficiencies of The Electrolysis Technologies

Table2.2 has been portrayed in Figure 2.2. It should be noted that the various electrolyzer techniques form clusters. The formation of these clusters is due to the many different additional costs included in the researches. While some papers include costs, such as PE and installments costs, others do not. Nevertheless, it should be noted that as of yet AEL remains cheaper than PEMEL, thus proving to be a preferred method from an economical standpoint.

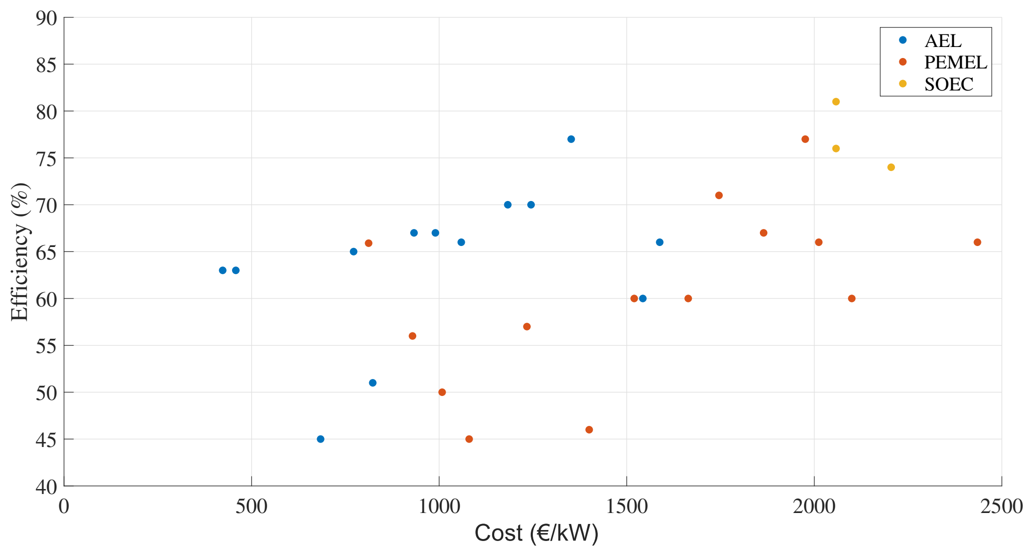


Figure 2.2: Overview of reported efficiencies versus cost €$_{2020}$ in Electrolyzers

As the included costs per research vary, this thesis opts to use averages of the data reviewed by [35], as this source provides the most thorough encompassing of costs. Therefore, a realistic representation of the total cost of the installation can be calculated. SOEC is excluded as a viable electrolysis technique, as limited data is available to provide a good approximate. Moreover, the technique is still in the developmental phase, thus rendering it unusable for large-scale applications. The given OPEX in the Tablebelow have been based on a system lifetime between 55000 and 120000 operational hours.

Type	Efficiency (LHV, %)	CAPEX (€$_{2020}$/kW)	OPEX (€$_{2020}$/kW)
AEL	55.5	1183	2.5% of CAPEX
PEMEL	53	1800	4% of CAPEX

Table 2.3: Average Efficiency and Cost for AEL and PEMEL (based on [35])

2.2.2 Future of Electrolysis

Decreasing costs are expected for the various electrolysis techniques, possibly making hydrogen production through electrolysis cost-competitive with conventional methods in the future. In the table below these expected costs have been grouped from the available literature, showing the expected development of electrolysis. SOEC has been excluded from this list, as future cost expectations on this technology are non-present.

Type	Efficiency (LHV, %)	CAPEX (€_2020/kW)	OPEX (€_2020/kW)	Year	Source
AEL	70	992		2030	[31]
AEL	66-70	818-942		2030	[65]
AEL	77	728		2030	[28]
AEL	68	480	2% of CAPEX	2025	[63]
AEL	65-71	400-850		2030	[47]
PEMEL	74	466		2030	[31]
PEMEL	65.9	507		2030	[53]
PEMEL	68-70	413-993		2030	[65]
PEMEL	77	624		2030	[28]
PEMEL	68	480	2% of CAPEX	2025	[63]
PEMEL	63-68	650-1500		2030	[28]

Table 2.4: Overview of the Future Costs and Efficiencies of Various Electrolysis Technologies

In conclusion, both AEL and PEMEL systems seem good contenders for hydrogen production, where AEL has an edge in both cost and efficiency, as the technique is more mature. This research will review both the application of AEL and PEMEL for hydrogen production while dismissing SOEC as a contender. Although SOEC shows strong potential for the future, the high cost and developmental phase of the technology render it non-applicable for large-scale applications as of yet.

2.3 Hydrogen Storage

After production, the hydrogen is ought to be stored. Transportation from production facilities to storage facilities is disregarded in this thesis, as it is assumed that these facilities are combined keeping transportation distances to a minimum. Many forms of hydrogen storage technologies have been and are being developed. Nowadays most hydrogen produced is stored in tanks. However, in the future mass hydrogen storage requires alternative methods of storage. In this section the various storage techniques in development are discussed.

2.3.1 Salt Caverns

A possible solution for hydrogen storage can be found in man-made caverns in salt layers ranging roughly 500 to 2000 meters below the surface [24]. The caverns can be created through a process called solution mining and can have volumes of up to a million cubic meters. Salt is both inert and impenetrable for hydrogen, thus making it a perfect natural container. Pressurized hydrogen is stored in the underground caverns making effective use of the available space. Furthermore, injection and withdrawal is highly flexible for this technique, making salt cavern storage also usable for peak shaving besides long-term storage [32]. In both the US and the UK some hydrogen salt cavern storage facilities are in use, proving the maturity of the technique.

In the Netherlands a variety of potential salt cavern locations exist and can be found in the eastern provinces of Gelderland and Overijssel, but also up north in the provinces of Drenthe and Groningen. Also, some salt caverns do exist offshore, however, they are not considered due to higher cost as well as additional technical difficulty. Extensive analysis, done by van Gessel et al., has discovered the most favorable locations in the Netherlands and has concluded, using a safety margin of 50%, that in total 321 salt caverns could be constructed, totaling an effective hydrogen storage of 155.7 PJ (43.25 billion kWh). This is divided over the three northern provinces of Groningen, Friesland, and Drenthe, where Groningen has the most potential [66].

Lastly, it is important to review the costs of hydrogen storage in salt caverns. The costs for hydrogen storage in salt caverns depend on a wide variety of parts, including surface materials to transports, pressurize and depressurize the material. Furthermore, the costs are strongly influenced by the excavation costs. In the literature, a variety of costs are provided, which are displayed in the table below. This research adheres to the range provided by Kruck et al., as these calculations were based on an actual design for a solution mined salt cavern [67]. Moreover, the design costs and technology were compared to in-use solution mined salt caverns in the US. The OPEX provided by Welder et al. is used for further cost calculations, as Kruck et al. do not provide operational costs.

Source	CAPEX (€$_{2020}$/kWh)	OPEX (€$_{2020}$/kWh)	Research Year
[67]	0.16-0.40		2013
[42]	0.52	2.5% of CAPEX	2019
[68]	0.044		2014

Solution mined salt cavern storage is an established technique, which has shown the possibility of hydrogen storage at a low cost. The technique seems to have reached maturity, making it a viable solution for long-term hydrogen storage. Furthermore, there are many suitable locations for hydrogen storage in the Netherlands. Therefore, solution mined salt caverns are considered as the storage method for hydrogen in the Netherlands.

2.3.2 Alternative Storage Methods

Many more technologies are available for long-term storage, however, most of them are not applicable for the purpose of this thesis. This section will shortly discuss the shortcomings for long-term storage in depleted gas fields, metal hydrides, liquid hydrogen, high-pressure hydrogen, and ammonia storage. A more extensive review of the shortcomings of these techniques and how they work is given in appendix A.3.1 to A.3.5.

Depleted gas fields have an enormous potential for storing hydrogen, however, the technology is as of yet unproven and limited research has been performed. Metal hydrides are limited for their application in long-term energy storage, as their weight percentage hydrogen storage does not compress the hydrogen extensively enough. Additionally, the method remains in the developmental phase, which results in high costs for hydrogen storage. Liquid hydrogen storage is predominantly limited for long-term storage, as it experiences a boil-off effect. This effect results in the evaporation of 0.2-0.3% of hydrogen on a daily basis, making the technique highly unsuitable [40]. High-pressure hydrogen storage's main issue is with regard to its cost per kWh stored, as costs for remain upwards of 10$ per kWh [69]. Solution mined salt cavern and depleted gas field storage thus easily out-compete high-pressure hydrogen storage. Lastly, ammonia storage seems to be a good competitor of hydrogen storage, as ammonia is much easier to handle. However, applications seem more suited towards short-term storage, due to the higher cost for the storage facility [39].

2.4 Reconversion of Hydrogen

Electricity shortages can be resolved by the reconversion of hydrogen into electrical energy, which can be done in a variety of ways. Fuel cells show promising results for this reconversion, however, direct consumption of hydrogen in gas turbines also seems to be a legitimate option. In this chapter, the various theoretical pathways for reconversion are discussed. Moreover, the associated economics of each pathway is reviewed, for which a wide variety of costs, such as grid connection, construction, power electronics, and more are considered.

2.4.1 Current State of Fuel Cells

The most logical method for the reconversion of hydrogen into electricity is the use of fuel cells. Various fuel cells have seen extensive research for applications in households to the well-known applications in the automotive sector. The three main methods are the Alkaline Fuel Cell (AFC), PEM Fuel Cell (PEMFC), and the Solid Oxide Fuel Cell (SOFC). The workings of an AFC are simply the reverse workings of an AEL. Instead of hydrogen output, one now inputs hydrogen and oxygen at the electrodes and water and electricity is the output. The same holds for PEMFC and the SOFC. This is somewhat of a simplification, however considering that an in-depth review of fuel cell operation is beyond the scope of this paper, no further theoretical explanation will be given. This account also holds for the PEMFC and the SOFC. For further reading on these topics, the reader could dive into the following sources [51], [46] and [70].

AFCs have been around for a considerate time, as their first application saw them being used as a power supply in the Apollo Missions. However, recent development has hampered, as the alkaline fuel cell life is extremely short compared to its competitors. Therefore, applications as stationary power supply become nearly impossible and render the technique unusable for long-term energy storage systems in their current state.

The more recently developed fuel cell can be found in the PEMFC, which has seen considerable development due to its application in the automotive sector. Where, however, in recent years it seems to have been out-competed by the electric vehicle. Nevertheless, its price has been dropping significantly over the past few years and the technique seems promising for large-scale stationary applications.

A promising fuel cell technique, currently only produced on a lab-scale, is the SOFC. Despite its developmental stage, much is expected from this technique as it has a considerably higher efficiency than PEMFCs and AFCs. Due to its current lab-scale, its hard to predict the exact applications for SOFC, however, reports are highly promising and the technique seems applicable for large-scale stationary applications.

The various techniques all come with their specific advantages and disadvantages, which is extensively discussed by Rouwenhorst et al. [39]. In the following table, these advantages and disadvantages have been grouped, after adaptation from their paper. Important drawbacks for AFCs are their short lifetimes and the reactivity of the electrolyte. With regard to PEMFCs a major drawback is the use of rare-earth materials. Disadvantages of SOFCs focus primarily on the high operating temperature and brittle components.

Type	Advantages	Disadvantages
AFC	- Room temperature operation [39] - Fast start-up [39] - High efficiency [71]	- Low lifetime [5] - Pure oxygen feed required [39]
PEMFC	- Near room temperature operation [39] - Fast start-up [39] - Commercially available [39] - Operation with air [39]	- Use of rare earth materials [60]
SOFC	- High efficiency [72] - Fast hot start-up [39] - Commercially available [72] - Operation with air [72]	- High operation temperature [72] - Slow cold start-up [73] - Brittle ceramic components [73]

Table 2.5: Advantages and Disadvantages of the various fuel cell techniques (adapted form [39])

Analyzing mainly these disadvantages, it can be concluded that AFC are not a suitable candidate for long-term large-scale energy supply, therefore, rendering the technique unsuitable for long-term storage applications. However, both PEMFC and SOFC show promising properties for large-scale applications, such as long-term energy storage. PEMFC have reached maturity levels due to their applications in the automotive sector and can operate in simple circumstances. Furthermore, their fast start-up is an advantage, as quick grid response will become a necessity in a more volatile grid. SOFC are highly researched, as they are significantly more efficient than their PEMFC counter-parts. Similar to PEMFC, they have a quick start-up time, although only when the SOFC is preheated. Considering the irregular use in the application of long-term storage slow cold start-ups are more common. Compared to PEMFC the materials needed for SOFC are much less rare, which is a huge advantage in large-scale applications. A global move towards fuel cells can put considerate stress on rare earth materials increasing cost of fuel cells, which depend on these materials.

In Table 2.6 the costs for the various FC technologies have been summarized. Important to note is lacking data for the OPEX, as large-scale stationary fuel cell systems are still an emerging technology. This research refers to the OPEX found for the equivalent electrolysis technologies as an approximate. Although these electrolysis OPEX are not entirely transferable to their fuel cell counterpart, they can be considered a good approximate. However, data on the OPEX for SOEC is also lacking, which is resolved by assuming similar OPEX for SOFC as for PEMFC.

Type	Efficiency (LHV, %)	CAPEX (€$_{2020}$/kW)	OPEX (€$_{2020}$/kW)	Source
AFC	60	1000-1200		[74]
AFC	42.3	182-635		[5]
PEMFC	30	1315-1945		[59]
PEMFC	60	1934-2413		[74]
PEMFC	39	770		[75]
PEMFC	27-41.4	2723-3630		[5]
SOFC	40	909-1370		[59]
SOFC	60	$\geq$ 2030		[74]
SOFC	55	551		[75]
SOFC	42.3-59.2	2723-3630		[5]

Table 2.6: Summary of Fuel Cell Costs and Efficiencies

These values in Table 2.6 are portrayed in Figure 2.3. Compared to the electrolysis data, the data on the cost and efficiency of FCs are much more dispersed, as the technology is much less established. Furthermore, the available research takes various sub-costs into consideration, but no one congruent overview is available. Therefore, no clear clustering can be seen, making it harder to determine which technology is currently more promising.

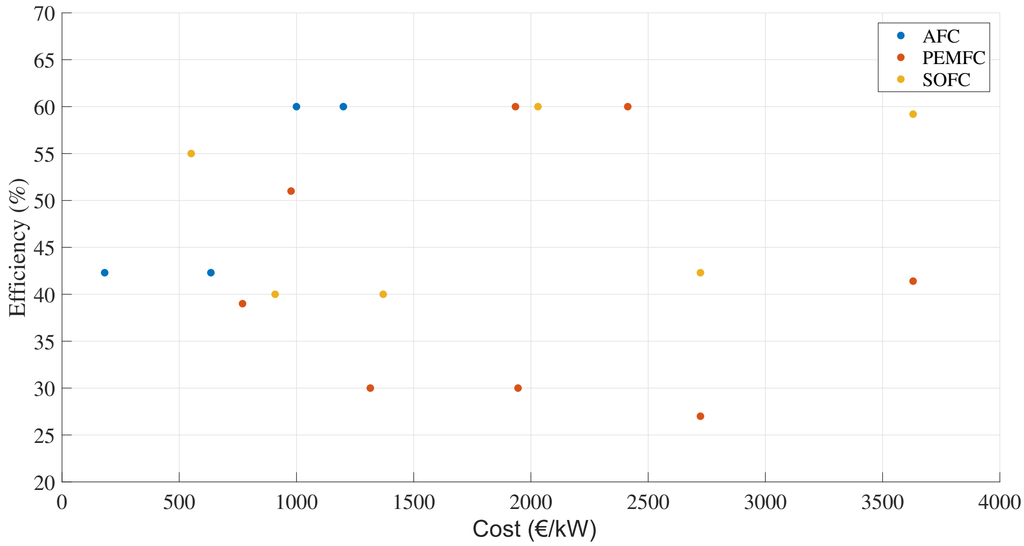


Figure 2.3: Overview of reported efficiencies versus cost $€_{2020}$ in Fuel Cells

This thesis opts to use the data provided by [59], as this research includes a wide variety of costs. Moreover, this research takes the effect of large-scale manufacturing into consideration, decreasing costs with increased production capacity. In this research, a Combined Heat and Power (CHP) applications for the FC technologies are reviewed. For this thesis, costs associated with the heat components will be excluded. Table 2.7 displays the average cost for PEMFC and SOFC have been given, based on the data from [59]. In their research, the Battelle Memorial Institute suggests that the machines have an expected lifetime of 20 years, while other research has found lifetimes 60000-90000 hours and 50000-60000 hours for PEMFC and SOFC respectively.

Type	Efficiency (LHV, %)	CAPEX(€/kW)	OPEX(€/kW)
PEMFC	30	1630	3.3% of CAPEX
SOFC	40	1140	3.3% of CAPEX

Table 2.7: Average Efficiency and Cost of PEMFC and SOFC (based on [59])

2.4.2 Future of Fuel Cells

The future costs of fuel cells, are unlike the future costs for electrolysis, highly uncertain. Hardly any research make suggestions for the development of future costs for stationary fuel cells, however, it is suggested in one source that costs will decrease with increasing production capacity [76].

2.4.3 Hydrogen Gas Turbines

Instead of reconverting hydrogen using a fuel cell, opportunities exist with regard to hydrogen fed gas turbines. In many countries, gas turbines form an essential part of the electricity supply, which is especially the case for the Netherlands. Therefore, in recent years further research has been done to develop gas turbines able to run on pure hydrogen [77] [78].

Although the technique seems promising, it is important to realize the serious efficiency loss of direct hydrogen combustion. The efficiency of the process can be significantly increased, when a Combined Cycle Gas Turbine (CCGT) is used, which is common in the Netherlands. Therefore, this thesis focuses on the application of CCGT for long-term storage applications. A CCGT reuses waste heat of a first steam engine to run a second steam engine. Considering that this requires a more elaborate system set-up, higher costs are expected. In an interview with two engineers from a large energy company, insight was given into the possibility of refitting current gas turbines with hydrogen suitable technology. The costs for such refitting were not disclosed, however, it was disclosed that costs would become roughly similar to the gas alternatives. Therefore, current costs for CCGT can be a good approximate.

An often-overlooked advantage, discussed by e.g. Zakeri and Syri, is the fact that by using GT AC electricity is generated in a classical manner. Conventional gas turbines provide frequency regulation as their power trains have rotational energy, which can dampen frequency distortions in the transmission network [10]. Systems that provide DC power, such as fuel cells, do not have these mechanical "reserves" thus increasing the vulnerability of the transmission network to frequency distortions. This is an often-overlooked advantage, as currently the effects of DC power supply are limited. However, it is predicted that with the further penetration of DC power supply, these effects will become more severe and are in need of a solution.

Table 2.8 contains the CAPEX and OPEX for hydrogen CCGT and GT, including a calculated average. The expected lifetime of the installations is 25 years.

Type	Efficiency (LHV, %)	CAPEX (€/kW)	OPEX (€/kW)	Source
GT (Hydrogen)	40	534	5.4	[79]
GT (Classical)	20-35	504		[80]
CCGT (Hydrogen)	60	805	11.7	[79]
CCGT (Classical)	60	819		[80]
Average				
GT	33.8	519	5.4	
CCGT	60	812	11.7	

Table 2.8: (Hydrogen) Gas Turbine Efficiency and Cost (CAPEX and OPEX) Summary

2.5 Variable Renewable Energy Sources

Lastly, the costs for VRES in the Netherlands are discussed. This section focuses on the three main methods of Dutch renewable energy generation: wind onshore, wind offshore and solar PV [81]. The actual power production, i.e. efficiency, of these VRES is not discussed in this section, as a model is specifically created for this purpose in chapter 3.

The costs of VRES have dropped significantly in recent years, making these power technologies (close to) competitive with fossil fuel energy generation methods [4] [82]. The costs regarding the different VRES are separated into two sub-parts: CAPital EXpenditures (CAPEX) and OPErational EXpenditures (OPEX). The CAPEX cover the installments costs in the widest of senses, including Balance Of System (BoS) costs, grid connection cost and more. What exactly is included is discussed per VRES in Appendix A.1. The main source for these costs was the overview "Renewable Power Generation Costs 2019", written by the International Renewable ENergy Agency (IRENA) [82]. This agency gathers a wide set of data across the globe on RES and their associated costs, providing an extensive overview and impressive database for the provided costs.

The CAPEX and OPEX are combined on the basis that all VRES system lifetimes are 25 years [82]. No discounting is considered in this research, to provide the most straightforward cost calculation. This leaves the following generalizing formula for the total cost of VRES.

$$TC_{VRES} = CAPEX + OPEX \cdot t_{lifetime} \tag{1}$$

Here TC_{VRES} and CAPEX are in €/kW, while OPEX is in €/(kW · yr). The total cost can be applied to the installed capacity to calculate the total cost per scenario. No inflation, discounting and cost-of-capital calculations are applied. This is purposefully done to provide a simple calculation, which gives a directly comparable value of the costs of various generation profiles.

Table 2.9 features all the final costs retrieved for the VRES.

	Total Cost [$€_{2020}$/kW]
Solar PV (utility-scale)	988
Solar PV (residential)	1631
Solar PV (commercial)	1187
Wind Onshore	2258
Wind Offshore	4627

Table 2.9: Overview of the costs of the VRES (based on [82] and [83])

Having covered the generation, the various sub-parts of the energy storage system are discussed.

2.6 Conclusion

In conclusion many technologies for the various sub-components of storage system are available, varying in costs as well as efficiency. The efficiencies of the various sub-parts of the system are a vital part of the total costs, as lower efficiencies increase surplus electricity as well as storage capacity needs. Therefore, a high efficiency is preferable, however, coming at a trade-off with costs. To summarize the numerous methods for electrolysis and reconversion, a total of six independent pathways have been devised, which costs are summarized in this chapter. The final determined pathways, for long-term hydrogen storage are:

	Electrolyzer		Storage Medium		Reconverion
Pathway 1	AEL	⇒	Salt Cavern	⇒	PEMFC
Pathway 2	AEL	⇒	Salt Cavern	⇒	SOFC
Pathway 3	PEMEL	⇒	Salt Cavern	⇒	PEMFC
Pathway 4	PEMEL	⇒	Salt Cavern	⇒	SOFC
Pathway 5	AEL	⇒	Salt Cavern	⇒	CCGT
Pathway 6	PEMEL	⇒	Salt Cavern	⇒	CCGT

Table 2.10: Pathways for Long-Term Energy Storage

The efficiencies for the independent processes in each pathway are given in Table 2.11, of which some were determined as averages of the efficiencies reported in chapter 1.5. Moreover, the costs are given in the Table 2.11, which are averages based on the costs reported in this chapter.

	Electrolyzer		**Storage Medium**	**Reconverion**	
	Cost (€$_{2020}$/kW)	η (%)	Cost (€$_{2020}$/kWh)	Cost (€$_{2020}$/kW)	η (%)
1	1922	55.5	0.45	2975	30
2	1922	55.5	0.45	2081	40
3	3600	53	0.45	2975	30
4	3600	53	0.45	2081	40
5	1922	55.5	0.45	1053	60
6	3600	53	0.45	1053	60

Table 2.11: Overview of Total Cost per Reviewed Pathway

3 Setting Up The Generation and Load Profile

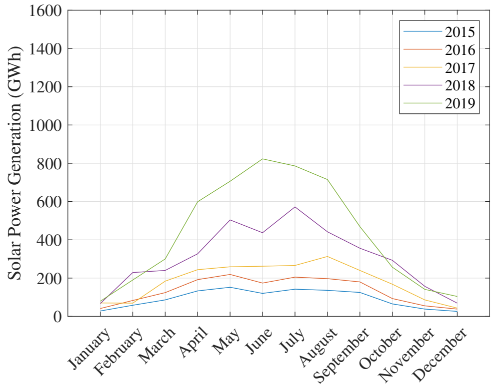
This chapter outlines how a generation and load profile is set up using data available from the CBS (Centraal Bureau voor de Statistiek, "Statistic Netherlands") and the KNMI (Koninklijk Nederlands Meteorologisch Instituut, "Royal Dutch Meteorological Institute"). By creating an accurate generation and load profile the need for long-term energy storage can eventually be determined.

Section 3.1 introduces the general issues regarding the uncertainty of weather profiles. Section 3.2 more accurately describes the wind weather profiles. Section 3.3 then discusses the solar weather profiles. Section 3.4 merges the previous sections to create one general generation profile only dependent on VRES capacity input. Section 3.5 elaborates how a representative load profile can be set up based on load data from the past. Lastly, section 3.7 concludes how combining the load and generation profile leads to insights in periods of shortage and surplus electricity.

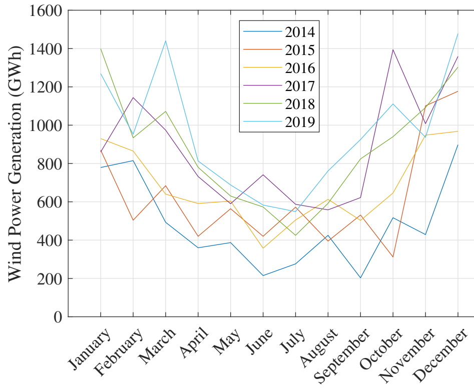
3.1 Uncertainty of Weather Profiles

Using data collected by CBS on Dutch VRES electricity production in recent years, a rough analysis on the recent past monthly VRES generation patterns, and thus monthly intermittency patterns, can be performed [81]. Furthermore, data is available on the monthly load demand in the Netherlands, helping to visualize consumption patterns [84]. Figure 3.1b and 3.1a show these monthly electricity generation patterns of wind, consisting out of onshore and offshore, and solar PV for the period 2014-2019. Additionally, the load profile during this time is shown in Figure 3.1c.

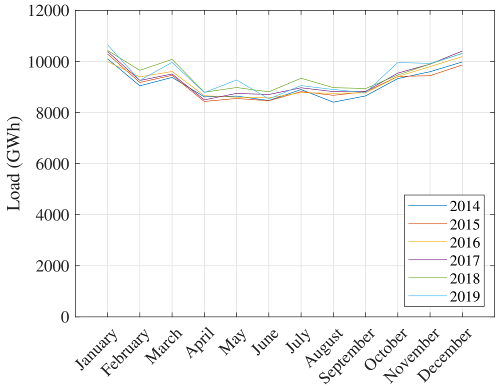
In Figure 3.1 various trends are present. Figure 3.1a clearly shows the development in the installed capacity of solar PV in recent years, as the monthly electricity generation increases significantly yearly. Furthermore, a clear trend concerning seasonal electricity generation is displayed in the solar data, where summer months are heavily leading in solar electricity generation. Figure 3.1b is slightly more difficult to analyze, as the data has a more chaotic and scattered nature. Nevertheless, a pattern can still be noticed, as monthly wind electricity generation generally decreases during the summer. Lastly, Figure 3.1c shows a decline in load demand during the summer period. These graphs, although being insightful, are not directly useful for analysis. The yearly changes in installed capacity and weather conditions require a normalization before this data can be more easily analyzed. Therefore, a normalization is performed using the known installed capacities for VRES in the Netherlands, while for the load profile it is normalized with regard to the total electricity consumption over the year. Subsequently, this normalization was then averaged over the six analyzed years to create an "average" year for electricity generation and load demand. The results are displayed in Figure 3.2.



(a) Monthly Solar Generation Netherlands



(b) Monthly Total Wind Generation (Off- and Onshore)



(c) Monthly Load Profile

Figure 3.1: Plots of Wind and Solar Electricity Generation and Load Demand in the Netherlands in the Period 2014-2019 [81, 84]

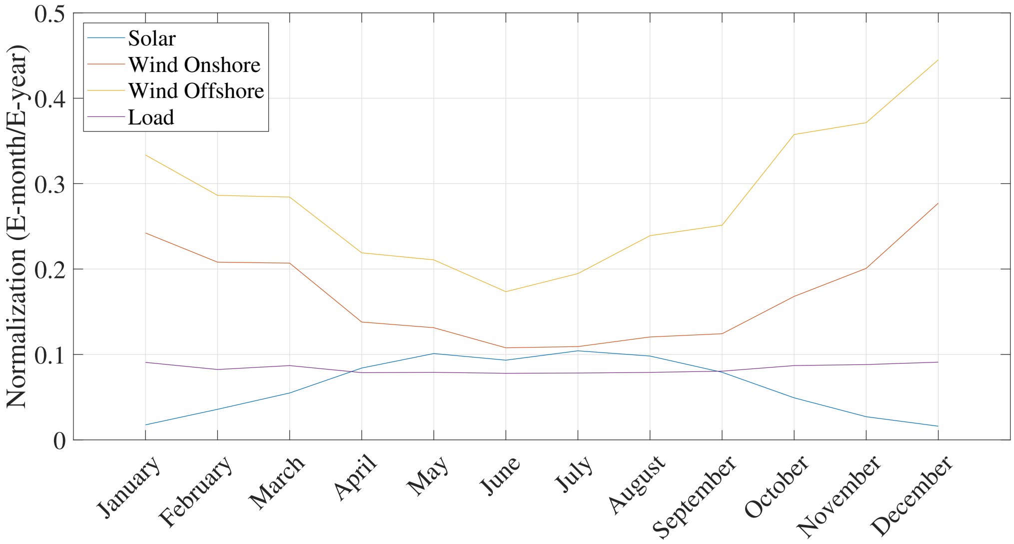


Figure 3.2: Averaged and Normalized Plots for Monthly Electricity Generation and Consumption (2014-2019)

These normalized figures now distinctly show the indicated patterns in the previous paragraph. Solar PV electricity production peaks in the summer, while wind (both on- and offshore) electricity generation dips during this period. Reviewing the normalized load pattern the decrease in load demand during the summer is visible, but generally trumped by the variability of the weather.

By averaging out the data, the strong variability of weather profiles is disregarded. Therefore, to reflect the uncertainty of the weather using the limited data available, a generation profile covering 31 years (period 1988-2018) is modeled. This generation profile is modeled by allowing for a certain (variable) mixture of VRES to be ”installed” in 1988 and considering its monthly power output since. Real-world data for VRES power generation, as displayed in Figure 3.1a and 3.1b, is used to create accurate average monthly capacity factors for each VRES separately. These capacity factors are thereafter corrected, using KNMI data, for past weather profiles in the period 1988-2018, effectively extending the data set. The KNMI has gathered data on solar irradiance and wind speeds throughout the Netherlands, two vital variables needed for calculating solar and wind energy generation [85]. By analyzing and processing the available historical data these past weather profiles can be identified. The past weather profiles are used as reference material for potential future weather circumstances. Using this method a monthly generation profile is created over the discussed period, where VRES capacity values are the variables. Furthermore, a load profile for the selected period is determined. An adequate load profile is generated using the yearly and monthly variability (determined as standard deviation) over the period 2007-2019.

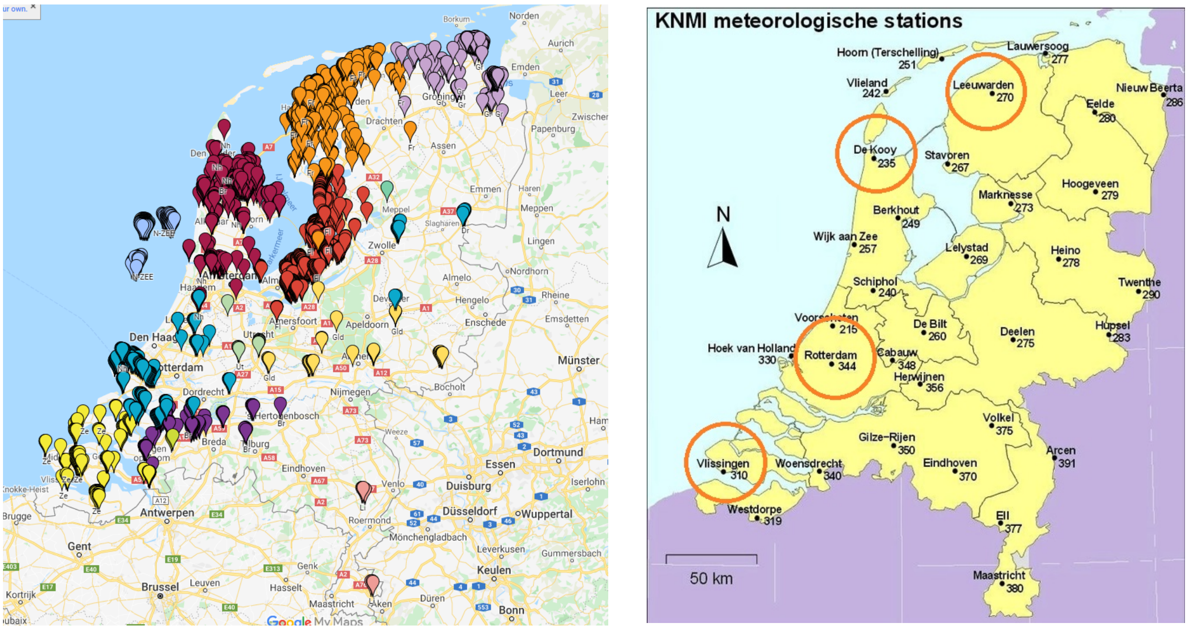
3.2 Wind Weather Profiles

Wind weather profiles are strongly influenced by landscape properties, where obstructions lead to slower and discontinuous winds. Offshore wind generally experiences a relatively smooth landscape, resulting in stronger and more continuous winds than their onshore counterpart. Subsequently, the resulting energy generation profile should be discussed separately. Firstly, the onshore wind profile and energy generation is discussed.

3.2.1 The Onshore Wind Profile

The onshore wind profile can be determined using wind speeds. Therefore, data points of the average daily wind speed over the period 1973 until 2019 are gathered from several locations across the Netherlands. This data has been gathered by the KNMI and the locations considered are displayed (circled in orange) in Figure 3.3b [85]. A higher resolution data set would be preferred. However, the KNMI only offers the daily average wind speed, therefore limiting the data set to these rough averages. The considered locations for the average daily wind speed are: Leeuwarden, De Kooy, Rotterdam and Vlissingen. These locations were chosen on basis of the dispersion of wind turbines in combination with the availability of historical weather station data by the KNMI. Although the chosen locations do not give a perfect representation of the location of wind turbines throughout the Netherlands, it does provide a close approximation. The map including all onshore wind turbines, and some offshore wind turbines, in the Netherlands, is displayed in Figure 3.3a.

The data retrieved from the KNMI weather stations provide the daily average wind speed at a location-specific height. Wind speeds increase significantly with height, therefore, these measured wind speeds must be corrected for height. Generally speaking, the hub height of a wind turbine is a good indication of the average wind speed experienced. However, in the Netherlands a variety of wind turbines, and thus varying hub heights, are in use, therefore a variety of wind speeds must be determined for wind energy generation. The height of onshore wind turbines has been analyzed by the CBS, thus allowing to determine the heights at which the wind speed must be determined [88]. The wind speed model used is generally referred to as the wind profile power law and is described by the following formula:



(a) Location of Wind Turbines in the Netherlands (Retrieved from [86])

(b) Selected KNMI Weather Stations (Retrieved from [87])

Figure 3.3: Maps Containing both Weather Station and Wind Turbine locations used to determine Energy Generation from Onshore Wind Turbines in the Netherlands

$$v = v_r \cdot \left(\frac{z}{z_r}\right)^{\alpha} \tag{2}$$

Here u denotes wind speed (m/s) at height z (m), u_r and z_r denote the relative wind speed (m/s) and height (m). The wind speed at height z can be calculated if the constant α is known. Depending on the landscape, various values for this constant are possible. In general cases, it is often set to 1/7, which is used in this research [89].
Wind turbines have a range of wind speeds for which they function, the so-called wind turbine power curve. Depending on the type of the wind turbine, a minimum wind speed (cut-in speed) for power production must be achieved before power generation can commence. Furthermore, wind turbines have a specific rated power, which is reached and maintained after a certain wind speed. Lastly, a wind turbine's operation can be stopped if wind speeds exceed a specific cut-out speed. Wind turbine power curves are turbine-specific but are mostly similar. A general wind turbine power curve has been attached in Figure 3.4.

Most wind turbines follow highly similar power curves, such as the one above, allowing to determine a cut-in speed and rated power wind speed that would suit most. Therefore, this research determined for onshore wind turbines a cut-in speed of 3.75 m/s, and a rated power wind speed of 12.5 m/s [90]. This generalization only has limited effect, and thus still provides accurate data.

The relation between the available power in wind and its speed follows a cubic term. Therefore the weather profile factor for onshore wind can not be directly calculated from the wind speeds, as higher wind speeds have a more significant effect. A simple wind power model is used, rewriting the gathered data on wind speeds into actual energy generated. The model used is the following

$$E = \frac{1}{2} \cdot \eta_{reconversion} \cdot \rho_{air} \cdot A \cdot v^3_{windspeed} \cdot t \tag{3}$$

The wind speed at the weather stations is determined in m/s at daily (onshore wind speeds) and hourly (offshore wind speeds) intervals. The other variables $\eta_{reconversion}$ (in %), ρ_{air} (in

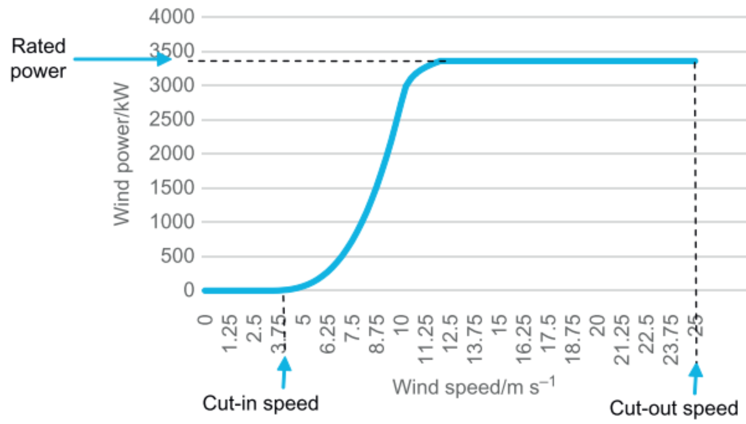
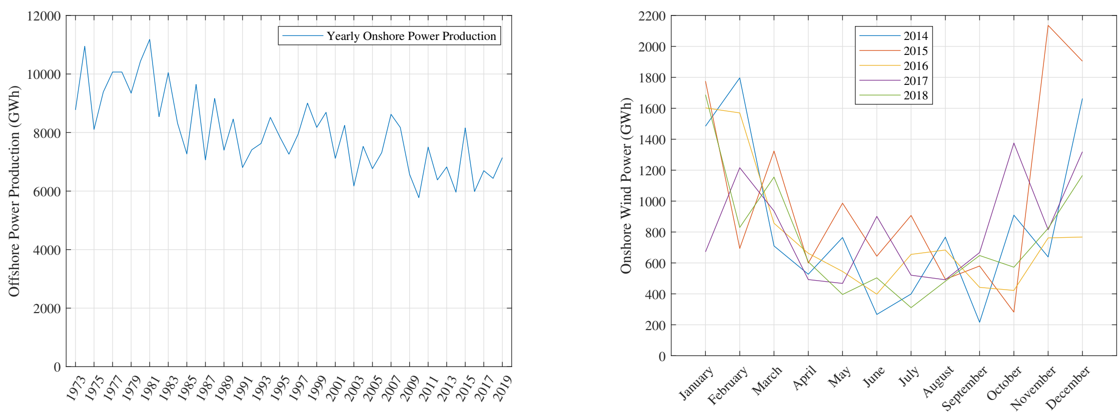


Figure 3.4: A Typical Wind Turbine Power Curve (Retrieved from [90])

kg/m^3) and A (surface area of wind turbines) can be found in a variety of sources, and were determined to be 45%, 1.225 kg/m^3 and 2259574 m^2 respectively [88] [90]. Here the surface area, and the associated energy generation, is split into several sub-parts, as different surface areas are present at different hub heights in the Netherlands. This resulted in a separation of five hub heights, for which power generation was calculated and summed. Subsequently, the data from the four weather stations were equally weighted and summed providing total average onshore monthly wind power generation data in the Netherlands.

In Figure 3.5 the calculated average onshore power generation is shown. This data is part of the data set, which is used to determine the monthly weather profile. Figure 3.5a indicates the yearly difference in average onshore wind power production, which is caused by the yearly variability of onshore winds. Figure 3.5b shows a "zoom-in", which displays the monthly variability between years. This "zoom-in" clarifies the inter-annual differences, but more importantly, indicates the need for long-term storage to even out the power generation distribution within a year. It is important to note that for reader interpretation purposes only limited data is displayed in the graph. The data set used to determine the weather profile factor is much more elaborate, but displaying it in its entirety would provide a chaotic non-usable overview.



(a) Calculated Yearly Onshore Power Generation (1973-2018, Netherlands Average)

(b) Calculated Monthly Onshore Power Generation (2014-2018, Netherlands Average)

Figure 3.5: A Display of the Variability of Monthly and Yearly Onshore Wind Power Generation

Based on Figure 3.5 monthly capacity factors for onshore wind power production can be determined in the period 1988-2018, not more data is used due to the limited available solar irradiance weather data. These capacity factors are eventually used to determine solar power production for varying capacities and represent the variability of weather circumstances in the reviewed months. The capacity factors are determined as follows.

$$k^{on}_{Jan_{1988}} = \frac{E^{on-cal}_{Jan_{1988}}}{P^{on-cal}} \tag{4a}$$

...

$$k^{on}_{Dec_{2018}} = \frac{E^{on-cal}_{Dec_{2018}}}{P^{on-cal}} \tag{4b}$$

Here the power generation per month (E^{on-cal}_{month}) is in MWh, the capacity (P^{on-cal}) is in MW (in fact it is 3436 MW) and the capacity factor (k^{on}_{month}) is in hours.

Figure 3.5 clearly illustrates the strong variance in onshore power generation throughout the years and months for one location. To visualize this pattern throughout the Netherlands, the monthly average normalized power generation including the standard deviation of onshore wind power generation is portrayed in Figure 3.6. The Figure exposes the strongly varying weather patterns as the monthly standard deviation values are considerable. Furthermore, the Figure highlights the strong seasonal (winter) focus for onshore wind power generation.

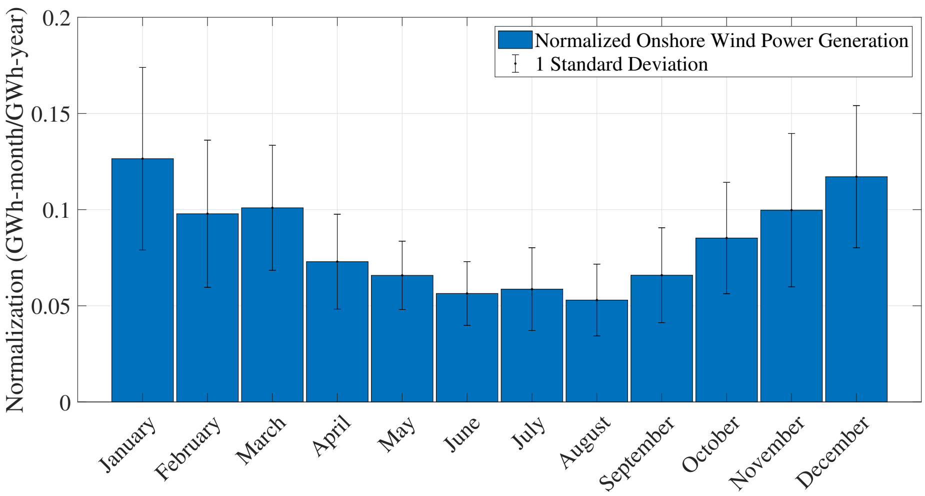


Figure 3.6: Normalized Average Onshore Wind Power Generation including One Standard Deviation

To calculate a weather profile correction factor, the power generation calculated for 2015 and 2018 is compared to real data provided by the CBS. This comparison is displayed for 2017 and 2018 in Figure 3.7. Differences between calculated power production and real power production could be due to the presence of several significant storms in the associated months. During storms, wind turbines are generally shut down, due to the extreme mechanical pressure generated on the blades by wind gusts. When assessing average wind speeds over 24 hours, these gusts are averaged out and are not properly reflected in the data. Therefore, the cut-out speed is seemingly not achieved, while in reality it could have been achieved during a significant part of the day. Furthermore, maintenance on the wind turbines is not considered in this model, meaning no downtime is considered, thus over predicting generation.

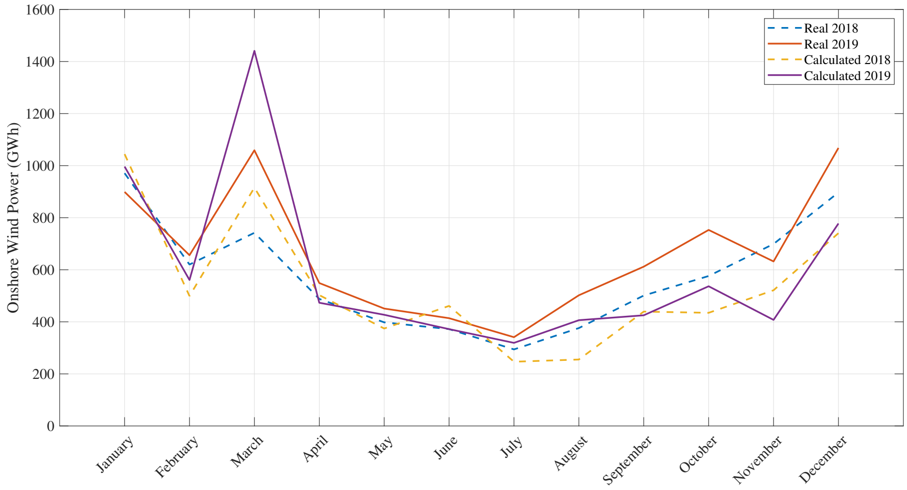


Figure 3.7: Comparing Real versus Calculated Onshore Wind Power Generation for 2018 and 2019

Therefore, the determined capacity factor requires a weather profile correction factor. By determining the difference between the calculated and the real onshore power generation, an error for the calculation can be determined. This correction factor can be applied to correct the error associated with calculation as portrayed in (3). This wind profile correction factor is determined monthly over the period 2014 to 2018 and averaged per month. These correction factors are calculated as follows.

$$w^{on}_{Jan} = \frac{1}{5} \sum_{i=2015}^{2019} \frac{E^{on-real}_{Jan_i}}{E^{on-cal}_{Jan_i}} \tag{5a}$$

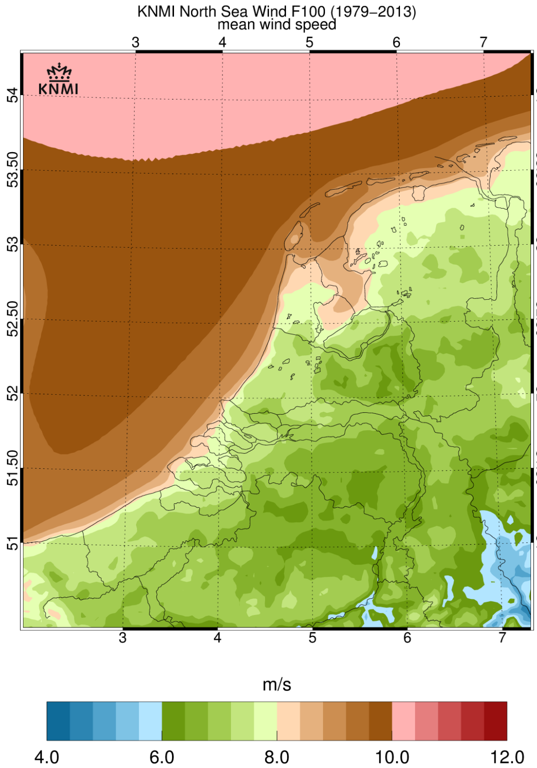
...

$$w^{on}_{Dec} = \frac{1}{5} \sum_{i=2015}^{2019} \frac{E^{on-real}_{Dec_i}}{E^{on-cal}_{Dec_i}} \tag{5b}$$

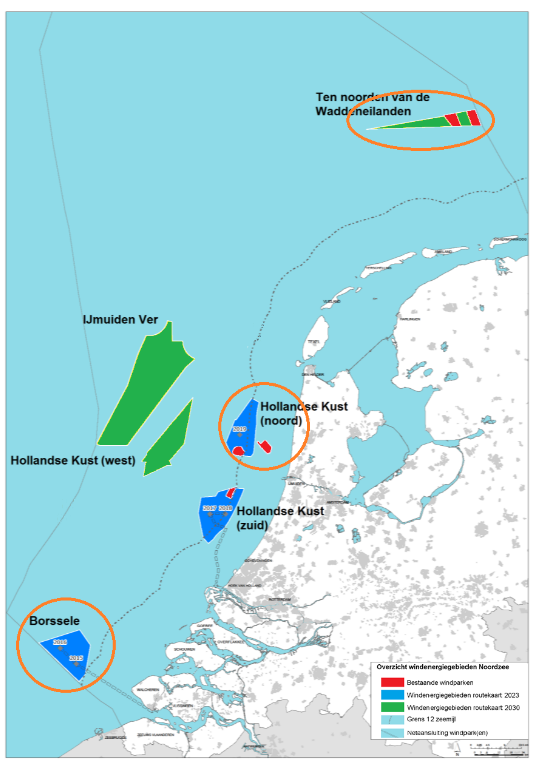
In these formulas energy (E) is in MWh, while the weather profile correction factor (w) is unitless.

3.2.2 The Offshore Wind Profile

The offshore wind profile is determined similarly to the onshore wind profile. Lacking extensive coverage from offshore weather stations, the KNMI conducted research modeling hourly average wind speeds across the North Sea for the period between 1979 and 2013, creating the KNW North Sea Wind Atlas. In this research, a climate model was used to determine hourly average wind speeds in a variety of offshore locations. Figure 3.8a shows a map based on this climate model. Furthermore, a map containing the various Dutch offshore wind farms is displayed in Figure 3.8b. Three of these locations, circled in orange, were chosen as data gathering points to determine offshore wind generation.



(a) KNW Atlas; Average Wind Speeds On- and Offshore (Retrieved from [91])



(b) Chosen Offshore Data Locations (Retrieved from [92])

It is important to note that these wind speeds were modeled and were not measured by weather stations. Nevertheless, the KNMI reports that the map is highly accurate and gives an extensive overview of offshore wind speeds, as the modeled values were tuned to onshore wind speed measurements from the Cabauw mast [93].

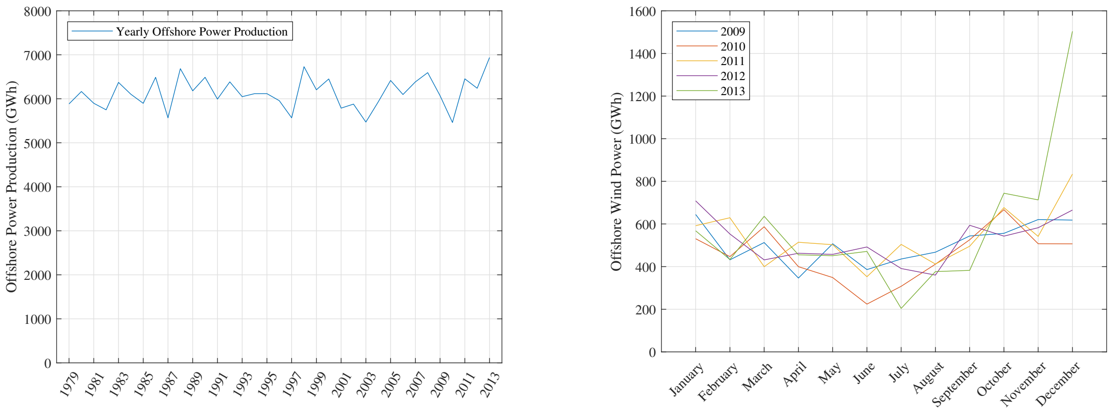
In contrast to onshore wind turbines, offshore wind turbines are much more homogeneous, as these are built-in sizeable wind farms. Currently, the Netherlands has four offshore wind parks: Gemini, Egmond aan Zee, Prinses Amalia, and Luchterduinen (halfway during this research Borssele 1 and 2 were dispatched). For these wind parks, much data is publicly accessible, therefore allowing for a more accurate calculation of offshore generated electricity. The data available on the various offshore wind parks are displayed in Table3.1.

Windpark	Size (MW)	Type	Hub Height (m)	A (m^2)	Cut-in Speed (m/s)	Cut-Out Speed (m/s)	Rated Speed (m/s)	Capacity Factor (%)	Source
Gemini	600	Siemens 4.0	88.5	1990984	5	25	12	49.4	[94, 95]
Egmond	108	Vestas V90	66	229022	3.5	25	15	33.3	[96, 95]
Luchterduinen	129	Vestas V112	81	372338	3	25	12	47.0	[97, 95]
Amalia	120	Vestas V80	60	301593	4	25	16	40.1	[98, 95]

Table 3.1: Data on the Various Offshore Wind Farms

Having acquired this data, the subsequent steps in the calculation of total offshore power generation are the same as for onshore. The offshore data model is, however, more elaborate than the onshore available data. Hourly average wind speeds are given at a variety of heights, thus reducing the need for the height-dependent wind speed model. (2) is still used, however, only a minor (< 10 meters) correction is needed. Having completed this correction the wind speed model as described in (3) in combination with the wind turbine power curve is applied. Performing this calculation an hourly offshore wind power generation profile is constructed for the three locations. These results are equally weighted and summed resulting in a total monthly offshore power generation profile.

Figure 3.9 shows the processed offshore power generation data for the Gemini wind farm. This data is part of a broader data set, which is used to calculate the weather profile factor, in this case for offshore wind. Figure 3.9a indicates the yearly difference in power generation at Gemini wind farm, which is caused by the yearly variability of offshore winds. Figure 3.9b shows a "zoom-in", which displays monthly variability between years. This "zoom-in" clarifies the inter-annual differences, but more importantly, indicates the need for long-term storage to even out the power generation distribution. Offshore wind power generation is slightly less variable than onshore wind power generation, however, outliers, such as December 2019 remain. It is important to note that for reader interpretation purposes only limited data is displayed in the graph. The data set used to determine the weather profile factor is much more elaborate, but displaying it in its entirety would provide a chaotic non-usable overview.



(a) Calculated Yearly Offshore Power Generation (1979-2013, Gemini Wind Farm)

(b) Calculated Monthly Offshore Power Generation (2009-2013, Gemini Wind Farm)

Figure 3.9: A Display of the Variability of Monthly and Yearly Offshore Wind Power Generation

Based on Figure 3.9, and further data, monthly capacity factors for offshore wind power production can be determined. In total 372 monthly capacity factors are determined for the period 1988-2018. These capacity factors are calculated as follows.

$$k^{off}_{Jan_{1988}} = \frac{E^{off-cal}_{Jan_{1988}}}{P^{off-cal}} \tag{6a}$$

$$\ldots$$

$$k^{off}_{Dec_{2018}} = \frac{E^{off-cal}_{Dec_{2018}}}{P^{off-cal}} \tag{6b}$$

Here the power generation per month ($E^{off-cal}_{month}$) is in MWh, the capacity ($P^{off-cal}$) is in MW (in fact it is 957 MW) and the capacity factor (k^{off}_{month}) is in hours.

From Figure 3.9 it can be concluded that the variability of offshore power generation is considerably less than onshore power generation. Nevertheless, some variance exists on both a yearly and monthly basis. To visualize this pattern throughout the Netherlands, the monthly average normalized power generation including the standard deviation of offshore wind power generation is portrayed in Figure 3.10. Comparing the standard deviation results to Figure 3.6 it can be concluded that the variance is indeed considerably less. Furthermore, although some seasonal importance for offshore power generation remains, it can be concluded that the power generation is more equally distributed throughout the year.

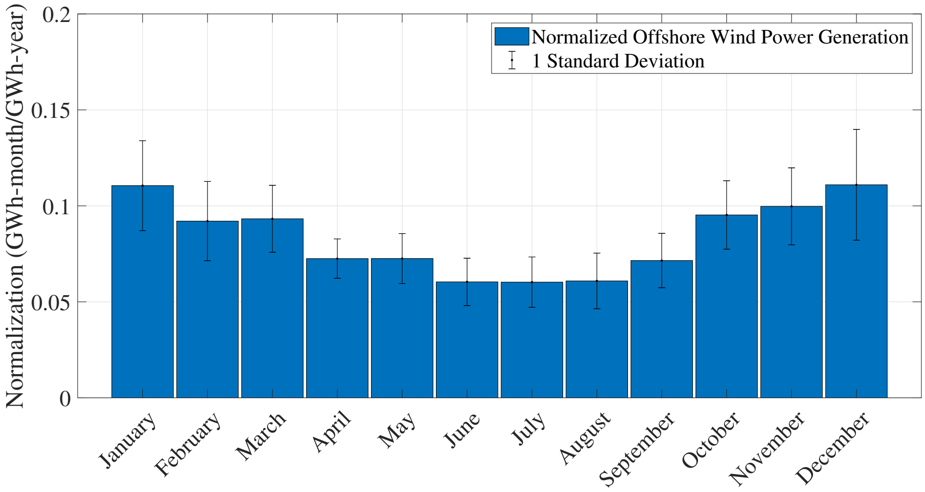


Figure 3.10: Normalized Average Offshore Wind Power Generation including One Standard Deviation

To ensure a more accurate offshore wind power generation calculation a wind profile correction factor (w_{off}) is determined. The initial calculation does not include many limiting factors for offshore wind power generation. Generally, offshore wind locations deal with much more extreme conditions, requiring wind turbines to shut down more often. However, also an important difference between the onshore and offshore data should be noted, as the KNW atlas provides hourly wind data, thus, in principle, incorporating the wind gusts more accurately compared to onshore data. Nevertheless, extremities remain, certainly more strongly offshore. Therefore, poorly represented extreme conditions still add to calculated surplus electricity generation. Furthermore, extreme offshore conditions also require more frequent maintenance on the wind turbines. Additionally, the wind turbines are harder to access, therefore increasing repair time considerably. Therefore, offshore wind turbine downtime is considerably higher, decreasing power production [99]. Lastly, a phenomenon only recently discovered is the impact of large offshore wind farms on the average wind speed at their locations. As wind farms are large obstructions, the average wind speed in front of the wind farm is decreased, where research has shown that this reduction in wind speed can be up to 3.4% [100]. This is an additional limitation to the power generation of offshore wind farms and causes that offshore wind speeds taken from the KNW atlas are over-estimations of actually experienced wind speeds when wind farms are placed. The general overestimation of offshore wind power generation is illustrated in Figure 3.11.

To compensate the considerate overestimation, the weather profile correction factor is calculated. This correction factor is determined by comparing the calculated data to real offshore wind power generation. This offshore wind profile correction factor is determined monthly over the period 2014 to 2018 and averaged and is calculated as follows.

$$w_{Jan}^{off} = \frac{1}{5} \sum_{i=2015}^{2019} \frac{E_{Jan_i}^{off-real}}{E_{Jan_i}^{off-cal}} \tag{7a}$$

...

$$w_{Dec}^{off} = \frac{1}{5} \sum_{i=2015}^{2019} \frac{E_{Dec_i}^{off-real}}{E_{Dec_i}^{off-cal}} \tag{7b}$$

In these formulas energy (E) is in kWh, while the weather profile factor (w) is unitless.

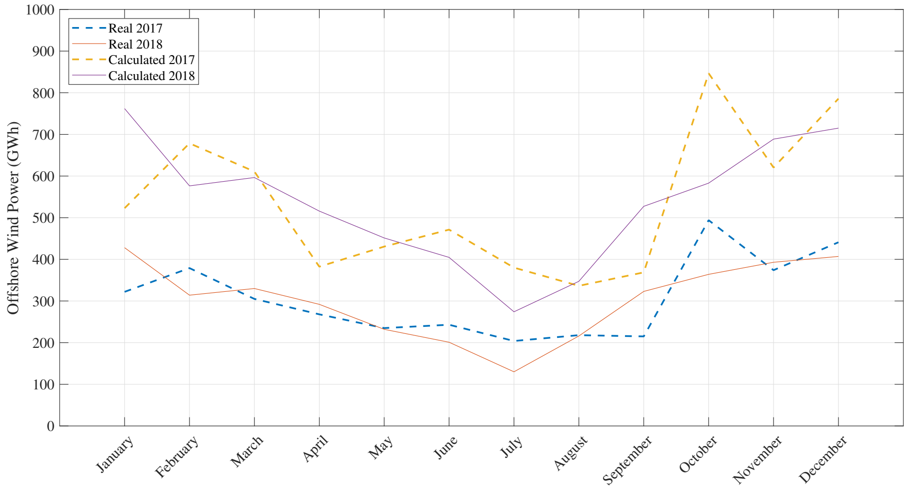


Figure 3.11: Comparing Real versus Calculated Offshore Wind Power Generation for 2017 and 2018

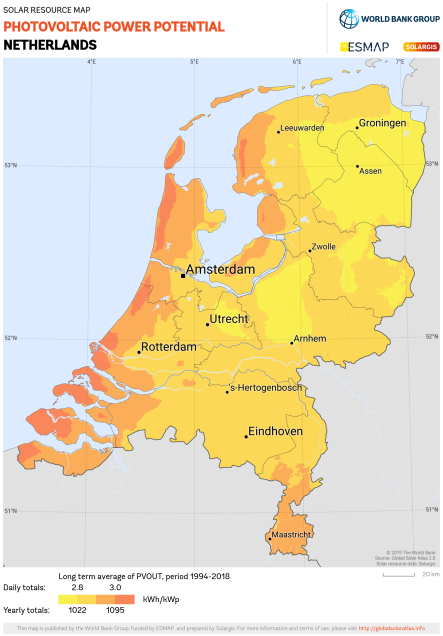
3.3 The Solar Weather Profile

In general, the solar weather profile is much more predictable than wind the wind weather profile, as the solar weather profile follows the seasons much more closely. Nevertheless, the month-to-month profile can have yearly differences, therefore the solar profile should also be closely inspected. Furthermore, solar irradiance differs slightly throughout the country. Therefore, a range of locations should be considered to give a good approximate of solar PV power generation.

Data provided by a range of KNMI weather stations can be used to calculate the solar weather profile [85]. These stations, containing daily data ranging back to 1988, give a considerate amount of data to base calculations on. In contrast to wind turbines, the locations of solar installations are not well documented. However, solar installations are placed in a variety of places, ranging from roofs to fields. It is assumed that the dispersion of solar installations in the Netherlands is roughly homogeneous. Following this mostly homogeneous dispersion of solar installations, an equally distributed set of weather stations has been chosen.

Data retrieved from these weather stations are in $\frac{J}{cm^2 day}$, therefore it can be rewritten into total power production with relative ease. This can be done by firstly, determining the average efficiency of solar panels. Secondly, the total covered area of solar panels in the Netherlands has to be determined. With these two values and the acquired data from the KNMI weather stations, the total energy production can be closely approximated. However, these intermediate calculations are not needed when determining the weather profile factor. The efficiency and covered area combine into a constant factor applicable to all data points, thus not influencing weather profile factor results. Nevertheless, the calculations are utilized to cross-check whether the KNMI data provides representative values for the generation profile.

Limited data is available on the surface area of solar installation in the Netherlands. However, the total power sizing of installations is documented by CBS, which can help determine the total size of installations in the Netherlands. On average, solar panel sizing lays around 285Wp having a size of $1.65m^2$. The total installed capacity of solar panels in the Netherlands accumulates to 4522MW in 2018 [81]. Therefore, it is estimated that 26.2 square kilometers of solar panels are placed in the Netherlands. Efficiencies of commonly used solar panels in the Netherlands vary between 12% and 20%, which can decrease depending on the orientation of the solar panel [101]. This thesis determined an average efficiency of 15% for all solar installations in the Netherlands. The following formula is applied to the data from every weather station, after which its results should be weighted to represent the dispersion of solar panels in



(a) Solar Irradiance Dispersion throughout the Netherlands

(b) Chosen KNMI Weather Stations (Retrieved from [87])

the Netherlands.

$$E_{sol} = Q \cdot \eta_{conversion} \cdot A_{PV} \cdot \frac{1}{3600000} \tag{8}$$

Here E_{sol} is in kWh/day, while Q is in J/(cm^2 day), $A_{solarpanels}$ is in cm^2 and $\eta_{reconversion}$ is a value between 0 and 1.

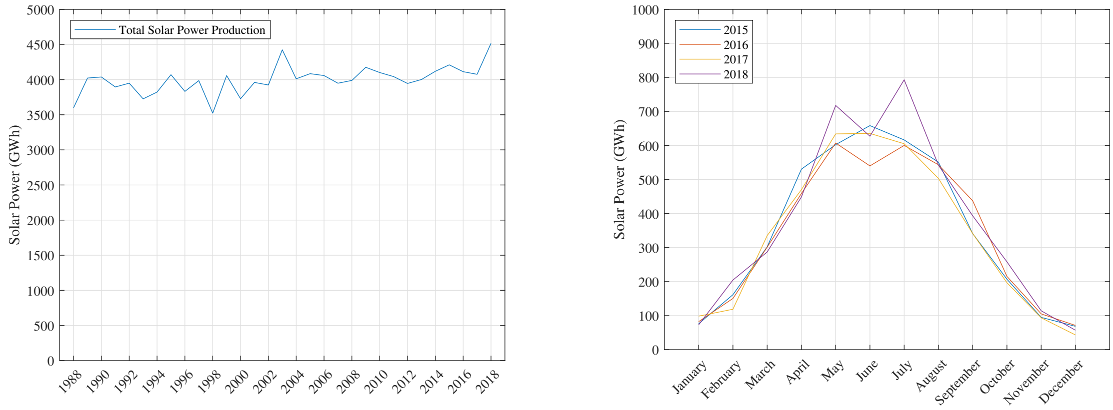
Figure 3.13 illustrates the average calculated solar power data from the weather stations. Figure 3.13a indicates the yearly difference in power generation for De Bilt weather station, which is caused by the yearly variability of offshore winds. Figure 3.13b shows a "zoom-in", which displays monthly variability between years. This "zoom-in" clarifies the inter-annual differences, but more importantly, indicates the need for long-term storage to even out the power generation distribution. For the solar irradiance, this aspect is even more clear than for the wind power generation, as the irradiance profile is strongly seasonally linked. It is important to note that for reader interpretation purposes only limited data is displayed in the graph. The data set used to determine the weather profile factor is much more elaborate, but displaying it in its entirety would provide a chaotic non-usable overview.

Using these calculated values, monthly capacity factors can be determined. These capacity factors are eventually used to calculated solar power generation for varying capacities. A total of 372 capacity factors are determined, one for every month in each year. These capacity factors represent the weather circumstances in the reviewed months. The capacity factors are determined as follows

$$k^{sol}_{Jan_{1988}} = \frac{E^{sol-cal}_{Jan_{1988}}}{P^{sol-cal}} \tag{9a}$$

$$\dots$$

$$k^{sol}_{Dec_{2018}} = \frac{E^{sol-cal}_{Dec_{2018}}}{P^{sol-cal}} \tag{9b}$$



(a) Calculated Yearly Solar Power Generation (1988-2019, Netherlands Average)

(b) Calculated Monthly Solar Power Generation (2015-2018, Netherlands Average)

Figure 3.13: A Display of the Variability of Monthly and Yearly Solar Power Generation

Here the power generation per month ($E^{sol-cal}_{month}$) is in MWh, the capacity ($P^{sol-cal}$) is in MW (in fact it is 4451 MW, as was determined before) and the capacity factor (k^{sol}_{month}) is in hours.

It can be concluded from Figure 3.13 that both the yearly and monthly solar radiation patterns are quite stable. To visualize this pattern throughout the Netherlands, the monthly average normalized solar radiation values including standard deviation are portrayed in Figure 3.14. The Figure strengthens the conclusion and shows a relatively small standard deviation throughout the year. The Figure further indicates a strong seasonal dependence in solar radiation, which is as expected.

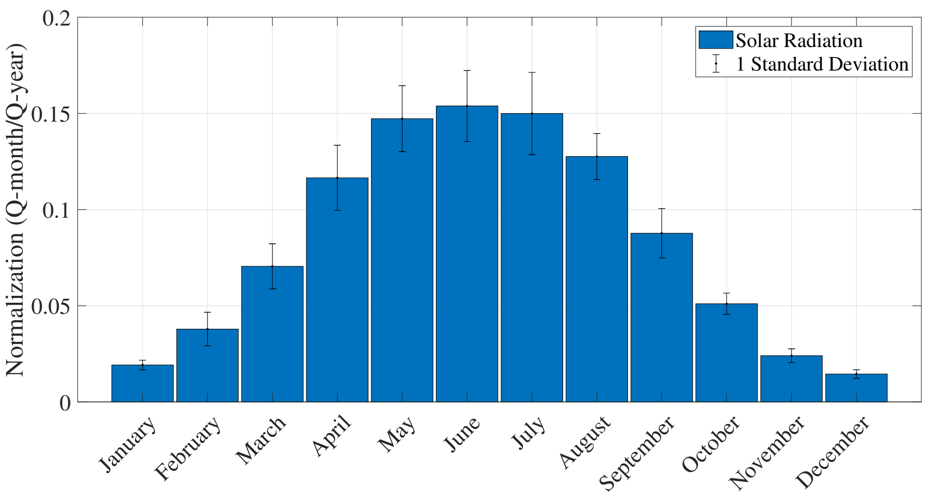


Figure 3.14: Normalized Average Solar Radiation including One Standard Deviation

Solar power generation has been calculated in the period 1988-2018, however, the accurateness of this calculation remains problematic. To correct for potential errors, due to, for example, mechanical issues, orientation efficiency deficiencies and other issues that have not been regarded in (8), a weather profile correction factor is determined. This is performed by comparing the calculated data in the period 2015 to 2018 with available real data from Figure 3.1. This is illustrated in Figure 3.15.

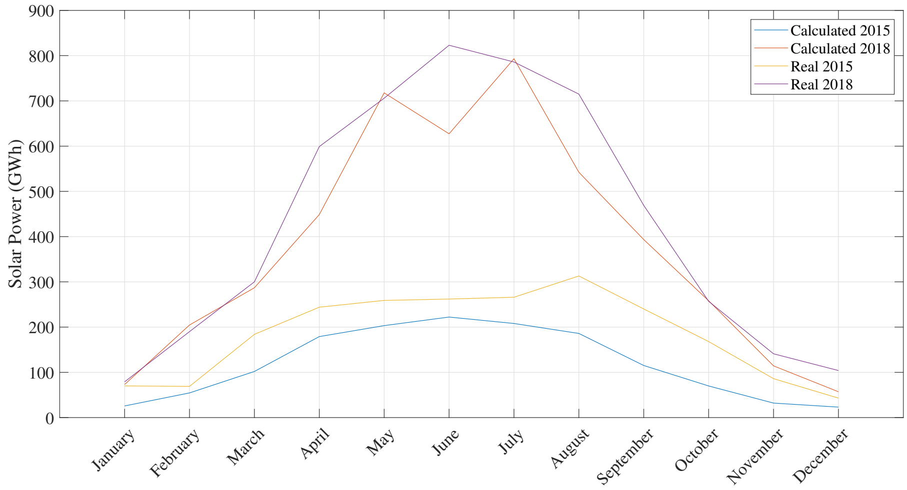


Figure 3.15: Comparing Real versus Calculated Solar Power Generation for 2015 and 2018

By calculating the difference between the calculated values and the real power generation for the period 2014 to 2019, an error for the calculation can be determined. This factor can be applied to correct the error from the capacity factor determined from the calculated solar data. This calculation is shown for the month of January in (10). These factors are ought to be set up for all months analyzed.

$$w^{sol}_{Jan} = \frac{1}{4} \sum_{i=2015}^{2018} \frac{E^{sol-real}_{Jan_i}}{E^{sol-cal}_{Jan_i}} \tag{10a}$$

$$\ldots$$

$$w^{sol}_{Dec} = \frac{1}{4} \sum_{i=2015}^{2018} \frac{E^{sol-real}_{Dec_i}}{E^{sol-cal}_{Dec_i}} \tag{10b}$$

In these formulas energy (E) is in MWh, while the weather profile factor (w) is unitless.

3.4 The Monthly Generation Profile

The generation profile of wind onshore, wind offshore and solar PV is determined using three main ingredients. These are the VRES capacity, the capacity factor (denoted as k with hours as unit) and finally the weather profile factor (denoted as w unitless). The following function calculates the 1988 January generation profile for onshore wind, offshore wind, and solar PV and shows how the set up equations interact.

$$E^{gen_{1988}}_{sol_{Jan}} = w^{sol}_{Jan_{1988}} \cdot k^{sol}_{Jan} \cdot P_{sol} \tag{11a}$$

$$E^{gen_{1988}}_{on_{Jan}} = w^{on}_{Jan_{1988}} \cdot k^{on}_{Jan} \cdot P_{on} \tag{11b}$$

$$E^{gen_{1988}}_{off_{Jan}} = w^{off}_{Jan_{1988}} \cdot k^{off}_{Jan} \cdot P_{off} \tag{11c}$$

The calculated generation profile is in MWh and is determined by the sizing of the VRES capacity variables (P_{sol}, P_{on} and P_{off}), which are in MW. It should be noted that to create the 31-year long generation profile, each formula is ought to set up for 372 months in total.

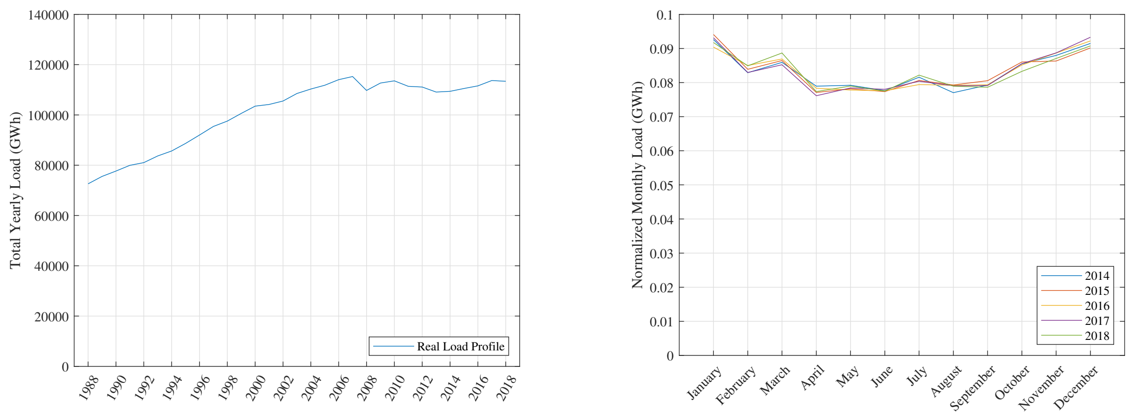
3.5 The Monthly Load Profile

In this section, the load profile for the period between 1988 and 2018 is set up, based on the real-world load profile provided by the CBS, as depicted in Figure 3.1 [84]. The CBS has gathered data on the Dutch load profile since 1976, however, due to population growth and the electrification of our society, electricity consumption has increased significantly over this period. This phenomenon is displayed in Figure 3.16a. Therefore, the load profile can not be directly applied, but instead should be generated for the period 1988 to 2018, following current electricity consumption levels.

Generating such a load profile can be performed in two steps. First, as can be seen in Figure 3.1 the consumption of electricity follows a monthly profile, dropping significantly in the summer. This consumption profile is apparent throughout history and can be analyzed through normalization of the data. This normalization is done by dividing the monthly electricity consumption by the total year consumption. This is shown for January 1988 in (12).

$$n_{Jan}^{1988} = \frac{E_{load_{Jan}}^{1988}}{E_{load}^{1988}} \tag{12}$$

Here n is a unitless value and both energies (E) are in kWh. These normalized values (shown for the period 2015-2019), together with the evolving load profile over the years is shown in Figure 3.16.



(a) Development of Yearly Total Power Consumption in the Netherlands 1976-2019

(b) Normalized Monthly Load Profile in the Netherlands 2015-2019

Figure 3.16: Overview of the Variation in Load Profile in the Netherlands Throughout the Years

Having acquired the normalization values for all 372 months, the standard deviation of these monthly normalization values is determined. This standard deviation is useful as it can be used in combination with a normal distribution to generate random realistic values for the load profile. The standard deviation is calculated per month and only displayed for the month January below.

$$\sigma_{Jan}^{n_{load}} = \sqrt{\frac{\sum_{i=1977}^{2019}(n_{Jan}^{i} - \overline{n_{Jan}^{all}})^2}{N-1}} \tag{13}$$

The resulting standard deviation ($\sigma_{Jan}^{n_{load}}$) is like the normalization unitless. The normalization including this standard deviation is shown in Figure 3.17. This Figure distinctly depicts the limited variability in the load profile, as the standard deviation is minimal. However, a slight pattern can be noted in the load profile as during the winter months power consumption is slightly increased.

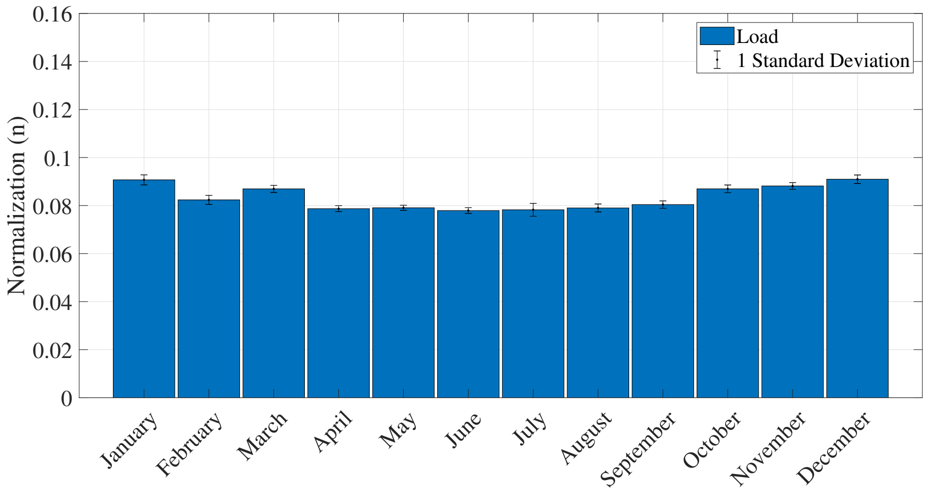
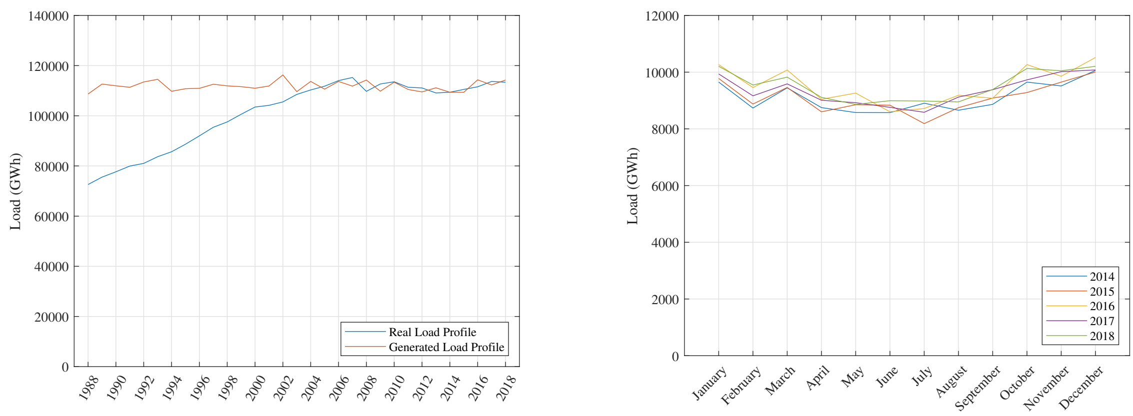


Figure 3.17: Normalized Average Load Profile Including One Standard Deviation

Secondly, the average yearly electricity consumption should be determined. Analyzing Figure 3.16a, it can be concluded that from 2007 onwards electricity consumption has stabilized. Therefore, the period between 2007 and 2019 can be accurately used to determine an average yearly electricity consumption. Furthermore, the standard deviation can be determined, which can once again be applied in a normal distribution to generate random realistic yearly electricity consumption values over the period 1988 to 2018. The calculation for this yearly electricity consumption standard deviation is shown in (14).

$$\sigma_{year}^{load} = \sqrt{\frac{\sum_{i=2007}^{2019}(E_i - \overline{E_{all}})^2}{N-1}} \tag{14}$$

Here the standard deviation (σ_{year}^{load}) is in kWh. Applying the standard deviation (1965 GWh) as a normal distribution to the mean (111951 GWh) allows to generate random realistic yearly total electricity consumption values, which can be transformed into random realistic monthly values using the mean and standard deviation from (13) applied with a normal distribution. The resulting generated yearly load profile is shown graphically in Figure 3.18a. Figure 3.18b shows a ”zoom-in”, indicating the monthly load fluctuations in the load profile.



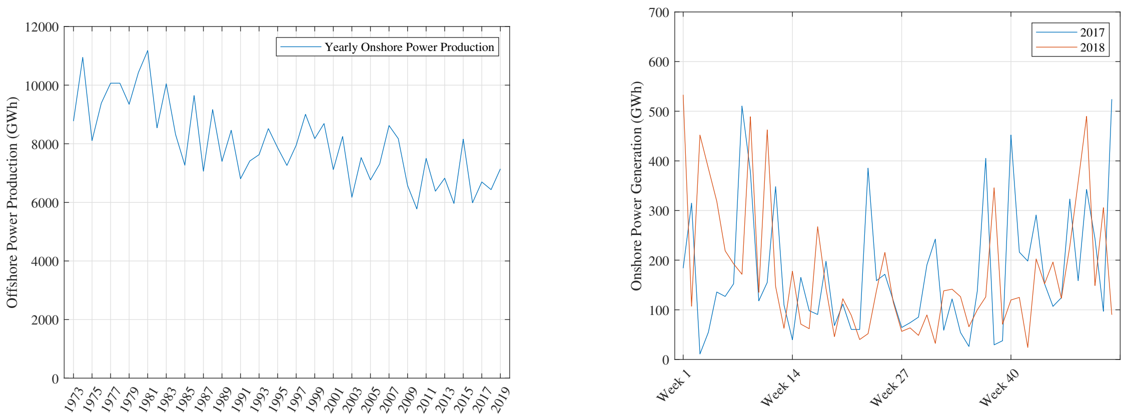
(a) Real versus Generated Load Profile (1988-2018) **(b)** Monthly Load Profile (2014-2018)

Figure 3.18: A Display of the Calculated Load Profile based on the Real Load Profile

3.6 The Weekly Generation and Load Profile

Apart from the monthly generation and load profile a smaller timeframe, the weekly generation and load profile, is also considered. When assessing monthly generation and load profiles, extreme weeks of shortage or surplus can be averaged out, making a considered month to become more average. To illustrate: imagine a month where during the first 3 weeks extreme shortages are experienced, however, in the fourth-week extreme weather conditions cause a major energy surplus. Whenever such a month is considered as a whole, these extremities are averaged out and the month potentially even seems to have no surplus or shortage. Therefore, a smaller timeframe allows to assess a more detailed load coverage.

The adjustment for the weekly generation profile comprises two steps. The available weather data contains daily data, therefore allowing for easy adjustment of the weather profile factors (w). Instead of averaging the data in months, it is now accumulated into weeks. The weekly power generation is calculated, following the method explained in section 3.2.1, but now using the weekly timeframe. An example of the calculated yearly onshore power generation and a "zoom-in" are shown in Figure 3.19. In these figures the even stronger variability of a weekly generation profile becomes apparent.



(a) Calculated Onshore Power Generation (1988-2018)

(b) Calculated Weekly Onshore Power Generation (2017-2018)

Figure 3.19: A Display of the Variability of Weekly and Yearly Onshore Wind Power Generation

This data helps calculating the capacity factor, which is determined similarly as before, however, now on a weekly basis. For simplicity, it is assumed that a year contains 52 weeks exactly. The additional day(s) are disregarded and it is assumed that the found solution will also be able to cover these disregarded days.

$$k^{on}_{Week1_{1988}} = \frac{E^{on-cal}_{Week1_{1988}}}{p^{on-cal}} \tag{15a}$$

$$\dots$$

$$k^{on}_{Week52_{2018}} = \frac{E^{on-cal}_{Week52_{2018}}}{p^{on-cal}} \tag{15b}$$

Lastly, the weather profile correction factor is determined using previously calculated monthly values. Considering that no weekly real power generation data is available, no new factors can be calculated. Therefore, the previously monthly factors are rewritten into weekly factors. Basically, all monthly weather correction factors are applied to the corresponding weeks in the considered month. This allows to find weekly weather correction factors for w^{sol}, w^{off} and w^{on}.

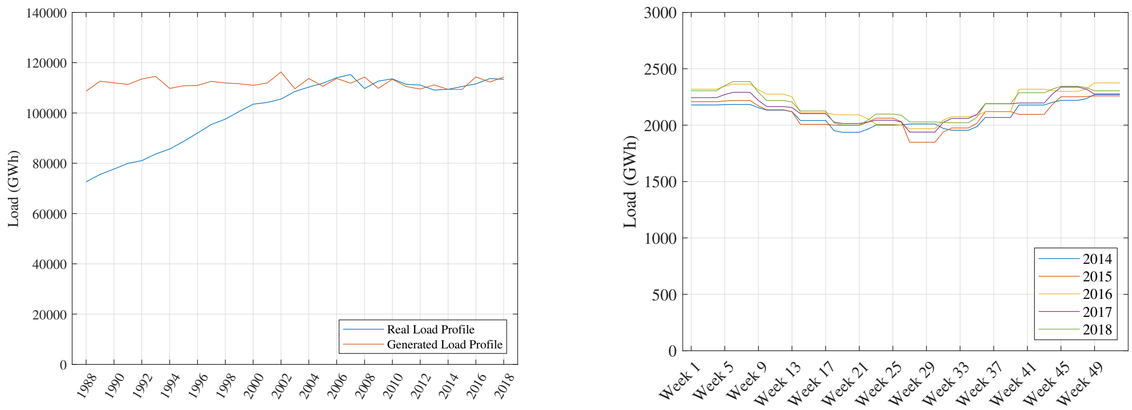
Having adjusted the weather profile and the capacity factors, the weekly generation profile is acquired by adjusting (11). The result is shown for Week 1 of 1988, the reader should notice that in practice a list of 1612 formulas like these are set up to cover the 31-year period.

$$E^{gen_{1988}}_{sol_{Week1}} = w^{sol}_{Week1_{1988}} \cdot k^{sol}_{Week1} \cdot P_{sol} \tag{16a}$$

$$E^{gen_{1988}}_{on_{Week1}} = w^{on}_{Week1_{1988}} \cdot k^{on}_{Week1} \cdot P_{on} \tag{16b}$$

$$E^{gen_{1988}}_{off_{Week1}} = w^{off}_{Week1_{1988}} \cdot k^{off}_{Week1} \cdot P_{off} \tag{16c}$$

Apart from the adjustments to the generation profile, the load profile needs a rework to adhere to the weekly timeframe. However, only monthly load profile data is available for the Netherlands, making it harder to model an accurate weekly load profile. Nevertheless, the monthly data can be transformed, similar to the capacity factor (k), into weekly values. Although this provides less accurate data, it can be considered a good approximate, as the load profile has shown to be quite stable throughout the months, illustrated in Figure 3.1c. It is assumed that this stability also holds for seperate weeks in each month. The monthly data is taken from the generated 31-year load profile as discussed in section 3.5. Figure 3.20b illustrates this weekly load profile for the period 2014-2018, based on the generated load profile from section 3.5 displayed in Figure 3.20a. The weekly load profile is not considerably different than the monthly variant, only experiencing smoother transitions between load changes.



(a) Real versus Generated Load Profile

(b) Weekly Load Profile for Period 2014-2018

Figure 3.20: Display of the Generated Weekly Load Profile based on the Real Load Profile

3.7 Conclusion

In conclusion, two generation and load profiles have been set up, covering both a weekly and monthly timeframe. By applying a VRES capacity to the generation profiles, the weekly or monthly VRES electricity generation over the period 1988 to 2018 is calculated. To visualize: by applying a certain VRES capacity, it is imagined that this capacity was installed in 1988, and ever since its power output has been monitored. The load profile, also over this period, is subtracted helping to find the mismatch between generation and load. Using this mismatch, months of shortages and overproduction are identified. This mismatch is used in chapters 4 and 5 to determine the VRES and storage facility capacity and their associated cost.

4 Achieving Energy Security Exclusively Using VRES

This chapter discusses achieving long-term (weeks/months) energy security (i.e. load coverage) exclusively using VRES, assuming that short-term (minutes/hours/days) storage is available. The load and generation profile, introduced in Chapter 3, are used to obtain results. A variety of scenarios are discussed, representing a range of societal circumstances. Additionally, two timeframes for energy security are independently reviewed for these scenarios: week and month. The results must cover weekly/monthly load demand between 0 and 100% of the years from the artificially generated load profile, using VRES power generation with weather circumstances as in the period 1988 to 2018. The variability of weather circumstances and the load profile can in theory be compensated by the correct sizing of the VRES capacity. Months and weeks with decreased VRES energy generation can be compensated by increasing installed capacity. Whenever the load demand is met through the available VRES, the redundant installed capacity is curtailed. Although this hurts the economic viability of VRES installations no additional costs are expected.

Section 4.1 discusses the optimization problems for the four scenarios and timeframes, week and month, considered. Section 4.2 to offshorefocussolevres review the "No Preference", "Onshore Opportunities" "Onshore Limitations", and "Offshore Focus" scenarios, respectively. Lastly, section 4.6 summarizes the findings and concludes on the relationship between cost and percentage load coverage, the effect of the timeframe and the consequences of the various scenarios.

4.1 Introducing the Various Scenarios and their Optimization Problems

In this section, the objective function, constraints, and solving algorithms applied to the two timeframes are shortly discussed. Various sets of constraints represent a number of scenarios to review societal effects on the total cost for achieving energy security exclusively using VRES capacity. In total, four different scenarios are reviewed: "No Preference", "Onshore Opportunities", "Onshore Limitations" and "Offshore Focus". However, first the two solving algorithms applied in these scenarios are examined.

First, a range of load coverage percentages is reviewed by using a MOGA, as was introduced in Chapter 1.4. The load coverage percentage represents the number of years in which each week's or month's (depending on the reviewed timeframe) load demand must be met. Thus, for a load coverage percentage of 10% in the monthly timeframe, all monthly load demands in 4 out of 31 years of the load profile must be covered. In fact, by increasing the load percentage more alternative weather circumstances are included for achieving load demand. More specifically, as the optimization finds the optimal solution, increasing the load coverage percentage, will result in the inclusion of years with more extreme weather conditions where generally VRES power generation is decreased. For the weekly timeframe, 10% load coverage simply enforces the optimization to cover all *weekly* load demands in 4 out of 31 years. The multi-objective optimization pursues to find optimal solutions for a set of objectives, acknowledging a better solution whenever either of the objectives is improved. The set of objectives considered for the various scenarios are thus the load percentage coverage and the cost. It is pursued by the MOGA to find a minimal cost solution, while simultaneously reviewing a range of load coverage percentages. Even if overall costs are increased as load coverage percentage is increased, the multi-objective optimization will consider this an improvement and note the solution, as one of the objectives is improved. Performing the optimization and comparing the results numerous times a set of optimal solutions for the multi-objective optimization is found. This set of solutions is the "Pareto Front", as no objectives can be further improved on this front.

Secondly, a single-objective optimization is performed to find the least cost solution for the mixture of Solar PV, Wind Onshore, and Wind Offshore capacities. These results are found using a GA. The primary goal is to provide load coverage at minimum cost. However, now load percentage coverage is fixed at 90%, thus load coverage is ought to be supplied in 28 out of 31 years. In other words, in 28 out of 31 years, the load demand in each month or week, depending on the reviewed timeframe, is ought to be covered by VRES power production. The fixed 90% load coverage is applied to find results that can provide weekly and monthly energy security in the majority of future weather scenarios, exempting extreme scenarios. Furthermore, fixing the load coverage percentage allows for analyzing the effects of the various scenarios.

These solving algorithms are applied to the previously mentioned four scenarios, wherein each scenario thus a weekly and monthly timeframe is considered. In the next sections, the objective functions and constraints representing the various scenarios and timeframes are clarified.

4.1.1 No Preference

First, the objective function and constraints for achieving monthly energy security in the "No Preference" scenario are discussed. Here the solving algorithms (both the MOGA and GA) minimize the following objective function, where the MOGA has an additional load percentage coverage input.

$$f(P_{sol}, P_{on}, P_{off}) = C_{sol} \cdot P_{sol} + C_{on} \cdot P_{on} + C_{off} \cdot P_{off} \tag{17}$$

Here P_{sol}, P_{on} and P_{off} are the variables and determined in MW, and the associated costs C_{sol}, C_{on} and C_{off} in €/MW and are as determined in Table 2.9. The result of the objective function provides the total cost, in $€_{2020}$, for a specific VRES capacity mixture.

The linear constraints in the "No Preference" scenario enforce the inclusion of the current VRES capacity mixture in the Netherlands in the final solution. However, a number of non-linear constraints exist, which apply based on the percentage load coverage. Generation through the VRES, as calculated in (11a), (11b) and (11c) using the variables from the objective function, must equal or be bigger than the load demand, as depicted in Figure 3.18, in various months depending on the reviewed percentage load coverage. The non-linear constraints become more restrictive as the percentage load coverage increases. A higher percentage load coverage forces the optimization to find solutions for a broader set of weather circumstances, thus also including more extreme scenarios with little potential for VRES power generation.

Secondly, an optimization problem to achieve weekly energy security in the "No Preference" scenario is set up. The objective function remains the same as in (17). Furthermore, the constraints to include the current VRES capacity still hold. However, the non-linear constraints are adjusted to represent the weekly generation and load profile. Generally, power generation through VRES must equal or be bigger than the load demand in all weeks in a specific number of years, depending on the percentage load coverage. VRES power generation is calculated using (16) and the weekly load demand is as in Figure 3.20. Lastly, as in the monthly timeframe, a higher percentage load coverage, makes the non-linear constraints more restrictive, forcing the optimization to cover load demand for a broader set of weather circumstances, which also include more extreme scenarios.

4.1.2 Societal Preference

In today's society, different opinions on the applications of VRES exist, which should be represented in the optimization problem. For instance, onshore wind has been protested strongly across the Netherlands, following the "not in my backyard" principle. Furthermore, visible offshore wind farms also have seen public disagreement and protests [102]. Lastly, solar PV installations have experienced mixed reactions from the Dutch population. An often-heard complaint is the loss of agricultural fields to utility-scale Solar PV installations [103]. In comparison, Solar PV on roofs of residential and commercial buildings has become mostly accepted, although some people still detest the sight [104].

To represent the societal preference on VRES, the optimization problem is altered by adding constraints to represent these preferences. In total three scenarios are analyzed. First, an ”Onshore Opportunities” scenario is considered, where only a minimal societal preference regarding VRES is represented in the constraints. Second, an ”Onshore Limitations” scenario is analyzed, where a more strong societal preference against onshore wind and utility-scale PV is reflected by more strenuous constraints. Lastly, an ”Offshore Focus” scenario is discussed, where the societal aversion on onshore wind and utility-scale PV is extremely strong and no further development of these VRES is allowed. The scenarios are predominantly constructed based on the book ”Klimaat Energie Ruimte”, which discusses the potential capacity for a variety of RES in the Netherlands [105].

For societal preference, two alternatives for power generation are added for all scenarios: Residential and Commercial Solar PV. The originally discussed Solar PV is now referred to as utility-scale solar PV ($solu$), while residential and commercial are referred to as res and com respectively. Therefore, the objective function is rewritten to the following

$$f(P_{solu}, P_{on}, P_{off}, P_{res}, P_{com}) = C_{solu} \cdot P_{solu} + C_{res} \cdot P_{res} + C_{com} \cdot P_{com} + C_{on} \cdot P_{on} + C_{off} \cdot P_{off} \tag{18}$$

Although the function looks elaborate, it is a relatively simple optimization problem between five different methods for power generation. The power capacity (P_{solu}, P_{res}, P_{com}, P_{on} and P_{off}) is once again denoted in MW, while the associated costs are in €/MW.

This objective function is bound by the linear and non-linear constraints as determined in 4.1.1. However, additional constraints are required to represent the societal preference for each scenario. The arguments for the constraints are here discussed per scenario, an overview of the constraints is presented in Table 4.1.

Firstly, the ”Onshore Opportunities” scenario represents onshore wind capacity constraints that focus on existing laws regarding safety zones in the built environment. Examples are noise zones in residential areas and safety zones for transport routes. Furthermore, some restrictions regarding protected wildlife are included when the total onshore wind generation capacity is considered. Lastly, the size of the wind turbines is not expected to further increase onshore, setting a limit at 3MW per wind turbine [105]. Depending on the future developments for offshore policy, the offshore wind capacity can have many ranges. Matthijsen et al. discuss several scenarios, where the most lenient and ambitious sees the potential for a maximum of 60 GW offshore wind capacity [106] by 2050. In addition to this, Dutch government plans indicate that in 2030 roughly 11 GW of offshore wind farms will be realized [107]. Therefore, to provide a more accurate representation of the predicted future energy mixture an additional constraint is added representing this goal. Furthermore, the available area for utility-scale solar should be determined. Agricultural ground is a cost-effective location for utility-scale solar farms, thus dominating the available locations for solar farms. In the ”Onshore Opportunities” scenario a potential of 10% of the agricultural ground is available for utility-scale solar farms, totaling at 150 GW of utility-scale solar farms. Concerning commercial and residential solar installations, an examination of available roof space is required. This examination has been performed by researchers at Deloitte finding 892 km^2 available roof space of which 36.9% would be residential [108]. This translates into a total capacity of 148.7 GW, assuming 275Wp solar panels.

Secondly, the ”Onshore Limitations” scenario introduces more strict onshore wind capacity limitations. The onshore wind constraint in this scenario is based on the limitation that no wind turbines should be placed in the close vicinity of buildings, keeping a minimum distance of 500 meters from **all** buildings in the Netherlands. This results in considerably less onshore wind capacity, which is reduced to 17 GW (assuming wind turbines of 3MW). All other constraints as discussed for the ”Onshore Opportunities” scenario are copied.

Thirdly, the ”Offshore Focus” scenario introduces further constraints on onshore wind capacity and also introduces a strict restriction on utility-scale solar farms. In this scenario no more than the current goals for onshore wind are realized, which is currently set at 6000 MW according to the Dutch 2023 Climate Agreement [109]. This constraint is considered in the ”Offshore Focus” scenario, as a scenario for a strong societal preference against onshore wind. In line with this detest of onshore wind (landscape view demolishment), no further utility-scale solar PV is allowed. All other constraints remain as in the ”Onshore Opportunities” scenario.

	Onshore Opportunities	Onshore Limitations	Offshore Focus
Solar PV (utility-scale)	$\leq$ 150 GW	$\leq$ 150 GW	0
Solar PV (residential)	$\leq$ 93.8 GW	$\leq$ 93.8 GW	$\leq$ 93.8 GW
Solar PV (commercial)	$\leq$ 54.9 GW	$\leq$ 54.9 GW	$\leq$ 54.9 GW
Wind Onshore	$\leq$ 50 GW	$\leq$ 17 GW	$\leq$ 6 GW
Wind Offshore	11-60 GW	11-60 GW	11-60 GW

Table 4.1: Overview of Constraints representing Societal Preference Scenarios

Lastly, the optimization problem to achieve weekly energy security for the societal preference scenarios is discussed. To review the weekly energy security timeframe for the various societal preference scenarios, the objective function as in (18) is applied. Furthermore, the weekly linear and non-linear constraints as discussed in section 4.1.1 still hold, however, to represent the societal preference, the constraints as illustrated in Table 4.1 are also enforced.

4.2 Achieving Energy Security: No Preference Scenario

This section discusses the results for achieving energy security using the optimization problem discussed in section 4.1 and for both the monthly and weekly timeframe. Thus, the constraints as represented for the ”No Preference” scenario in Table 4.1 and the objective function from (17) are applied. First, results for the monthly timeframe are discussed.

This section discusses the results for achieving energy security for the first scenario: the ”Onshore Opportunities” scenario.

4.2.1 Achieving Monthly Energy Security

First, this section shortly discusses the Pareto Front for achieving monthly energy security, after which the 90% load coverage results are discussed more in-depth, reviewing the found VRES capacities in particular.

Performing the multi-objective optimization, a Pareto Front as is displayed in Figure 4.1 is obtained. The total cost for load coverage ranging between 50 and 100% is displayed. Total costs commence at around 160 billion Euros at 50% load coverage and initially increase linearly. However, towards higher percentage load coverage, total costs start to increase more steeply and exponentially increase towards 300 billion Euros as 100% load coverage is achieved. To put the found total costs in perspective, the total yearly public finances of the Netherlands is roughly 300 billion Euros. The exponential increase in costs for the highest percentage load coverage is a logical consequence, as more and more improbable weather circumstances are ought to be covered for higher load percentage coverage, requiring additional VRES capacity. Therefore, for higher load percentage coverage, much installed VRES capacity becomes mostly redundant throughout the 31-year period, only to be used in a few specific months. This results in much redundant VRES capacity, which adds sharply to the total cost.

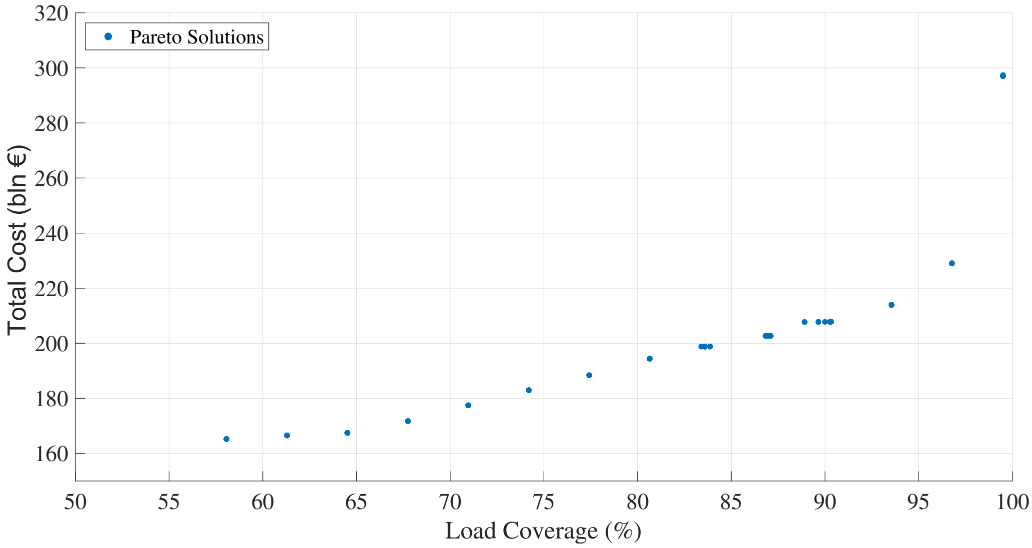
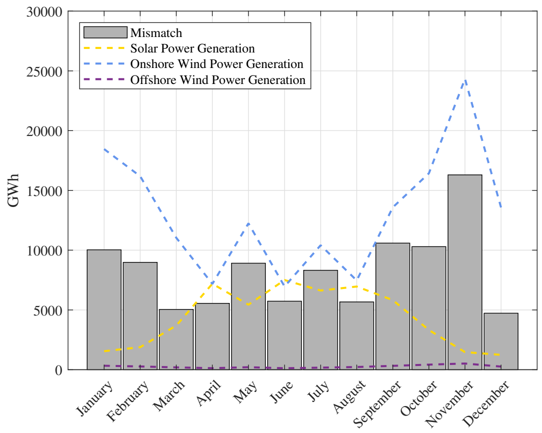


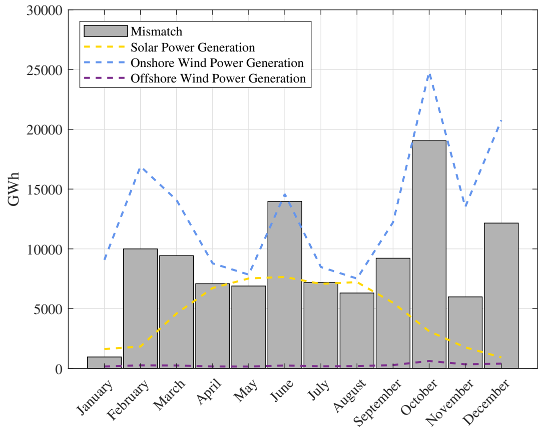
Figure 4.1: Monthly Energy Security: The Pareto Front for the "No Preference" scenario

To review the results more in-depth, the load percentage coverage is fixed at 90% and the single-objective optimization is performed. The mismatch profile of this optimization is provided in Figure 4.2, showing two years (1995 and 2017) in the 31-year period. It is noted that considerable surplus generation of electricity throughout the year is needed to accomplish energy security exclusively using VRES capacity expansion. To adhere to the constraints, the found VRES capacity must provide load coverage for every month in 28 out of 31 years (90% coverage), therefore, it must provide load coverage for at least 336 months out of the total 372 months. Weather circumstances vary strongly, resulting in months with favorable and unfavorable conditions. Additionally, the load profile varies throughout the year, however, playing a minor role compared to the weather circumstances for achieving energy security. To provide load coverage for these 28 years, the month with the least favorable weather circumstances and/or highest load will form a binding constraint and determine the VRES capacity. Thereafter, automatically load coverage is provided for all other months, as their weather circumstances and/or load are more favorable ensuring energy security. However, this does result in much redundant VRES capacity in these months, which causes the considerate surplus energy generation throughout the years and thus much curtailment.

This surplus electricity generation is illustrated in Figure 4.2. The "constraining" months are December 1995 and January 2017. However, they are both not globally binding, as in these months surplus energy generation is apparent. In fact, October 2007 is the binding month, as no mismatch between generation and load exists. This is the globally binding month, i.e. the globally binding constraint. The mismatch profiles in Figure 4.2 do clearly show the effect of weather patterns on electricity generation. Monthly differences in predominantly wind power generation cause spikes and drops in the generation, and thus mismatch, throughout the year. This is particularly visible for both June and August in 1995, where decreases in wind power generation (i.e. "quiet" wind months) substantially lower the surplus electricity. October 2017 is the prime example of a strong peak month in wind power generation. As can be concluded from the figures, onshore wind energy is the primary source for power generation, while generally also having a stronger effect on the mismatch profile, as power production differs considerably month-to-month and year-to-year.



(a) Mismatch and Generation 1995



(b) Mismatch and Generation 2017

Figure 4.2: Monthly Mismatch and Generation Results for Two Independent Years for the "No Preference" Scenario

The Solar PV, Wind Onshore, and Offshore capacities for the initial optimization are described in Table 4.2, excluding currently present VRES capacity. Furthermore, the result of the objective function, the total cost of the VRES capacity, is provided. The results show a mixture between various generation methods, however, it should be noted that, although totaled installed capacities are similar, onshore wind is the primary power generation method, as Figure 4.2 illustrates. At current prices for Solar PV and Offshore Wind, Onshore Wind remains the most cost-effective method for achieving monthly energy security. Moreover, Offshore Wind power generation is non-existent, as this remains a highly costly method for power generation. Although the capacity factor for Offshore Power generation is considerably higher than Onshore Wind and Solar PV, the high investment costs are not outweighed. Lastly, the solution relies considerably on Solar PV capacity, as this is a cost-effective method for load coverage during the summer. Although the capacity factor of Solar PV is considerably lower than both Onshore and Offshore Wind, the low cost of the technology allows for a cost-effective implementation in the energy network.

	90% Coverage
Solar PV (MW)	61706
Wind Onshore (MW)	64637
Wind Offshore (MW)	0
Total Cost (bln €)	206.91

Table 4.2: Monthly Energy Security: VRES Capacity and Costs for a "No Preference" Scenario

4.2.2 Achieving Weekly Energy Security

First, the Pareto Front for weekly energy security is discussed after which the 90% load coverage results is discussed more in-depth. Here the found VRES capacities are reviewed and compared to the monthly timeframe results.

Figure 4.3 illustrates the Pareto Front for the weekly timeframe in the "No Preference" scenario. Generally, costs have increased significantly, more than doubling for the entire load percentage spectrum. This strong cost increase is a result of renewable energy scarce weeks, which drive up the capacity needs to provide load coverage considerably. When assessing a monthly timeframe, these renewable energy scarce weeks are averaged out, preventing extreme scenarios that are incorporated in a weekly timeframe. To clarify, imagine a random month where 100

MWh of renewable energy is generated, using a random VRES capacity mixture. Accordingly, on average roughly 25 MWh of energy is generated per week. However, the first two weeks of the month had clear skies with a strong breeze, while the latter weeks of the month saw overcast days with little wind. Hence, the vast majority of the total 100 MWh renewable energy is generated in the first two weeks, while the latter weeks have little contribution. Thus when a weekly timeframe is considered, load coverage is now to be achieved with a period with generally very little renewable power generation, due to bad weather circumstances. Load demand remains roughly the same for all weeks, also in the weeks with little power generation. Consequently, additional VRES capacity is required, which drives up the total cost considerably. Furthermore, a linear rise in costs for increasing load coverage can be noted initially, however, towards the final 10% load coverage a more exponential increase in costs occur. As discussed in section 4.2.1, the final 10% load coverage contains more and more improbable scenarios, e.g. years with extreme weather conditions, causing this serious increase in total cost.

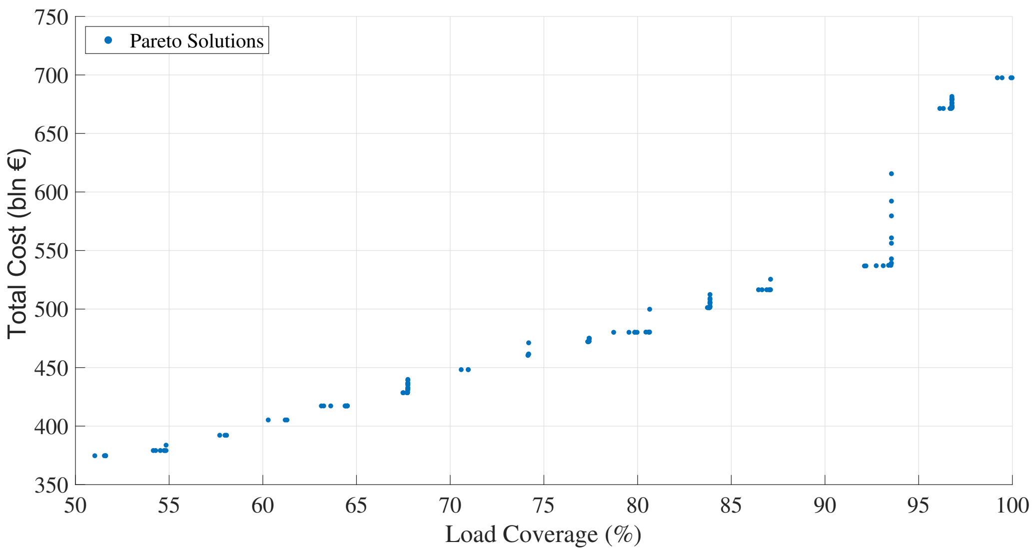


Figure 4.3: Weekly Energy Security: The Pareto Front for the "No Preference" scenario

90%

A more in-depth review, where the load percentage is fixed at 90%, provides insight into this severe increase in cost. As the timeframe has become smaller, periods of generation shortage have become painfully clear, requiring the capacity to increase exponentially to ensure adequate load coverage. Therefore, extreme electricity surplus occurs in the weeks with good weather circumstances. The effects are demonstrated in Figure 4.4, where the extreme electricity surplus is apparent. Adding all positive mismatch it can be concluded that the surplus energy generation more than triples and comes close to quadrupling. Furthermore, in contrast to the monthly timeframe solution, Solar PV power generation has become the primary source, often generating more than double the power generated through Onshore Wind sources. Lastly, Offshore Wind is also introduced in the VRES capacity mixture, however, having a limited contribution to the load coverage.

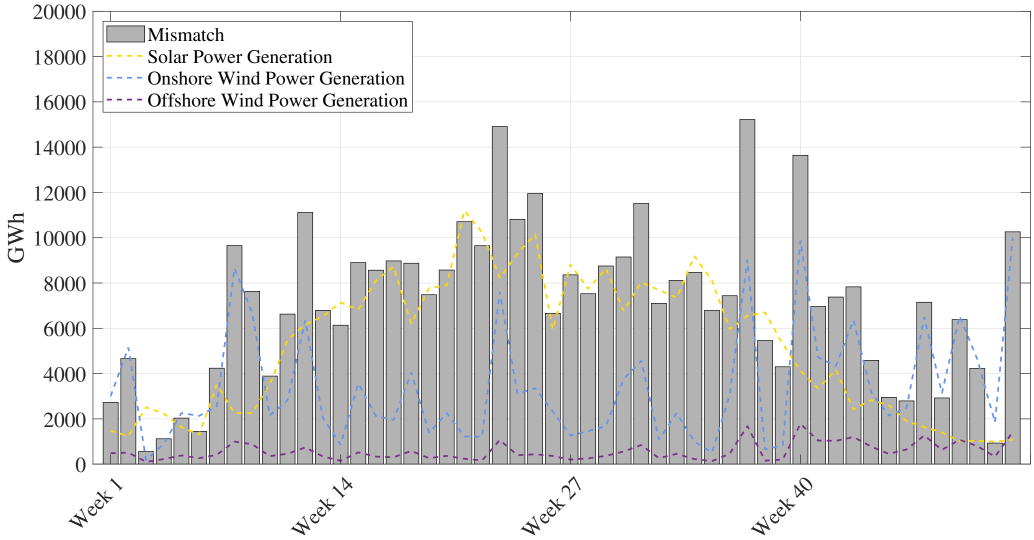


Figure 4.4: Monthly Mismatch and Generation Results for 2017 in the "No Preference" Scenario

The extreme VRES capacities that are required and cause the more than doubling in total cost, are displayed in figure 4.3. Comparing the results to the monthly timeframe, the quintupling in solar PV capacity is the most apparent. Assuming solar panels of 275 Wp and 1.65 m^2, an area larger than the province of Utrecht would be required. Onshore and offshore wind capacity increases only slightly, although the introduction of offshore wind capacity is noteworthy. It must thus be concluded that, although being considerably more expensive per MW, offshore wind capacity can be a vital addition to the VRES capacity mixture when a smaller timeframe is considered. Nevertheless, it remains highly questionable whether the extreme capacities found in this optimization can realistically be installed, considering the area required. Lastly, it is important to stress that, as was discussed before, the majority of produced electricity is curtailed and thus lost, which has become even more critical for the weekly timeframe. Therefore, most capacity is redundant, only to be activated in some weeks with extreme weather circumstances.

	90% Coverage
Solar PV (MW)	330770
Wind Onshore (MW)	72491
Wind Offshore (MW)	7852
Total Cost (bln €)	526.82

Table 4.3: Weekly Energy Security: VRES Capacity and Costs for the "No Preference" Scenario

4.3 Achieving Energy Security: Onshore Opportunities Scenario

This section discusses the results for achieving energy security for the first scenario: the "Onshore Opportunities" scenario. The objective function from (18) is used, and the constraints as portrayed in 4.1 are applied. The scenario is analyzed for two timeframes, week and month, applying the objective function and constraints as discussed in section 4.1.

4.3.1 Achieving Monthly Energy Security

First, the Pareto Front for the "Onshore Opportunities" scenario is shown and discussed, after which the percentage load coverage is fixed at 90% to review the effects of the societal preference on the VRES capacities.

The new constraints, reflecting societal preference, have an evident effect on the Pareto Front, increasing it compared to the "No Preference" scenario over the entire range of load percentage coverage, and specifically for higher load percentage coverage. The constraint for limited onshore wind capacity and a minimum amount of Offshore Wind capacity force the optimization towards the less cost-effective Offshore Wind, adding expensive VRES capacity. Therefore, costs increase much more significantly as higher load coverage is required, as is displayed in Figure 4.9. Towards 100% load coverage, additional costs upwards of 50 billion Euros are expected, an increase of roughly 15% compared to the "No Preference" scenario.

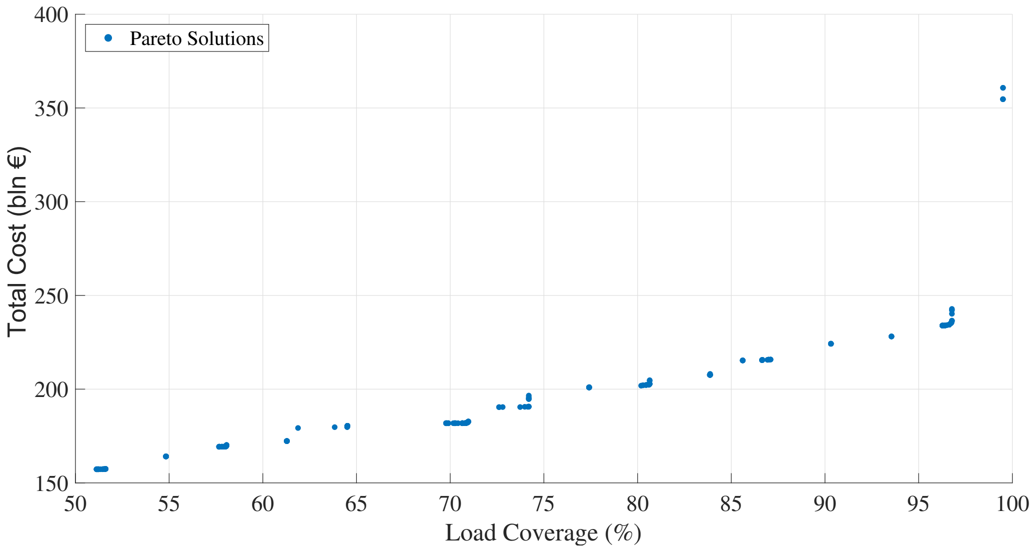
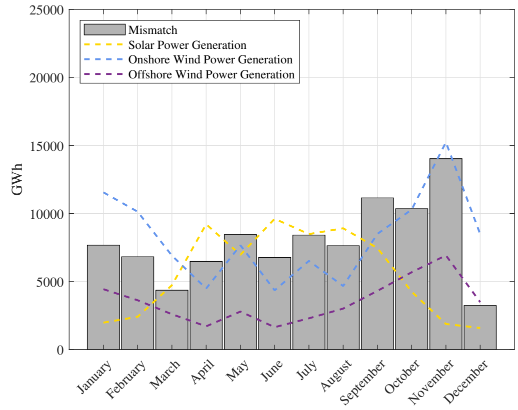


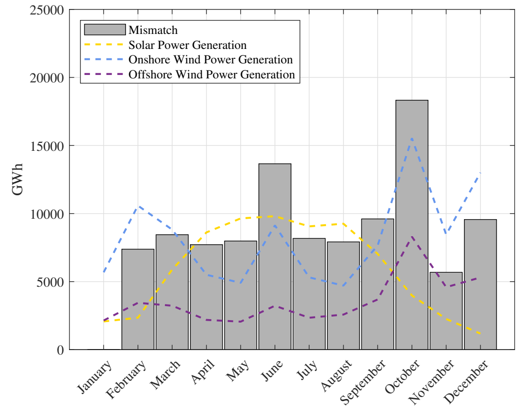
Figure 4.5: Monthly Energy Security: The Pareto Front following "Onshore Opportunities" Scenario

Fixing the load percentage coverage at 90% allows to review the origin of this increase in total cost. Comparing to the "No Preference" scenario the onshore and offshore wind constraints are binding. The limit on onshore wind capacity is predominantly covered through the expansion of offshore wind capacity, which was mostly enforced through the offshore wind constraint regardless. However, this expansion in offshore wind capacity results in additional total costs. Residential and commercial solar PV are unused, as the constraint for more cost-effective utility-scale solar PV is not yet binding. As offshore wind capacity is now an important part of the VRES capacity mixture, its power generation throughout the year is visible in Figure 4.6. Most notably, the global binding constraint is visible in Figure 4.6b, as the month January experiences zero mismatch, perfectly balancing load and generation.

As displayed in Table 4.4, the costs for the "Onshore Opportunities" scenario have increased by roughly 17 billion Euros compared to the "No Preference" scenario. This is an expected result when more costly offshore wind energy capacity replaces onshore wind capacity. Furthermore, a stronger dependence on solar PV capacity is apparent, as the capacity increases by roughly 30%. Thus, generally, the decrease in onshore wind capacity is covered through the expansion of both offshore wind and solar PV capacity. Nevertheless, the increase in costs is still limited, as the added constraints limit VRES capacity only slightly.



(a) Mismatch and Generation 1995



(b) Mismatch and Generation 2017

Figure 4.6: Monthly Mismatch and Generation Results for Two Independent Years in the "Onshore Opportunities" Scenario

		90% Coverage
Onshore Opportunities	Solar PV Utility (MW)	77632
	Solar PV Residential (MW)	0
	Solar PV Commercial (MW)	0
	Wind Onshore (MW)	38124
	Wind Offshore (MW)	13163
	Total Cost (bln €$_{2020}$)	223.69

Table 4.4: VRES Capacity and Costs for a "Onshore Opportunities" Societal Preference Scenario

4.3.2 Achieving Weekly Energy Security

Assessing weekly energy security with societal preferences as in the "Onshore Opportunities" scenario, it must be concluded that no energy security can be achieved. Reviewing the constraints as discussed in Table 4.1 and comparing to the "No Preference" scenario results (Table 4.3), already capacities far beyond the feasible capacity for the "Onshore Opportunities" scenarios are found, as illustrated in Table 4.1. However, there is room for Offshore Wind capacity expansion, nevertheless, even expanding this VRES capacity to its limit no feasible solution exists. Considering that the "Onshore Limitations" and "Offshore Focus" only see more strenuous constraints regarding VRES capacity, also no feasible solutions exist for these scenarios. In other words, to achieve weekly energy security acknowledging societal preference constraints, too much space for VRES capacity is required. Therefore, it must be concluded that **no** weekly energy security can be provided exclusively using VRES when societal preference is taken into consideration.

4.4 Achieving Energy Security: Onshore Limitations Scenario

This section discusses the results for achieving energy security for the "Onshore Limitations" scenario. The objective function from (18) and constraints as discussed in section 4.1 and portrayed in Table 4.1 are applied. Furthermore, the scenario is analyzed for two timeframes, week and month.

As further restrictions on onshore wind capacity are applied in the "Onshore Limitations" scenario, an increase in total costs on the Pareto Front for the entire load percentage coverage range are found. Generally, the linear increase in costs with respect to load percentage coverage remains, furthermore, the more exponential increase in costs towards 100% load coverage also remains present. On average, the Pareto Front is roughly increased by 50 billion Euros compared to the "No Preference" scenario, a considerate increase caused by the further restriction with regard to cost-effective onshore wind power generation.

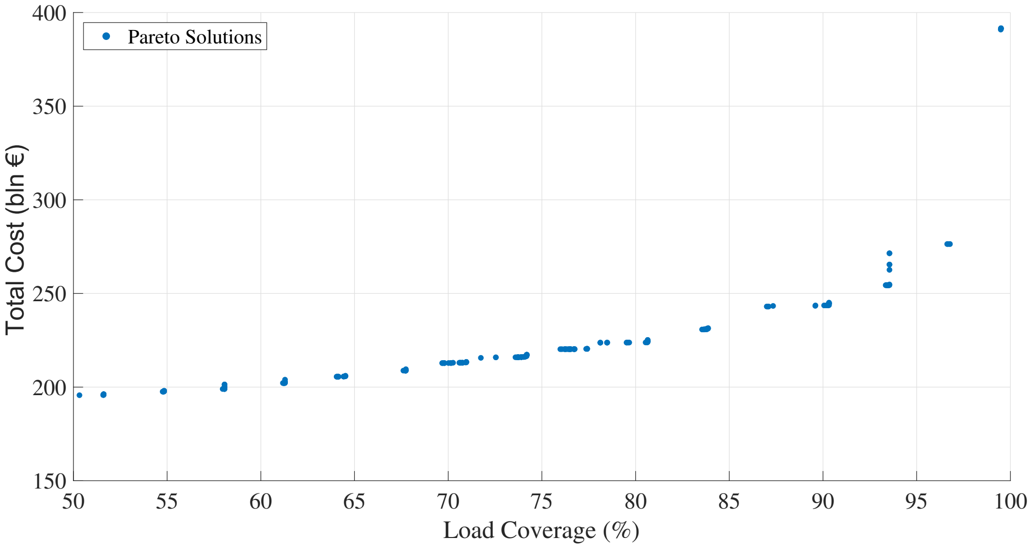
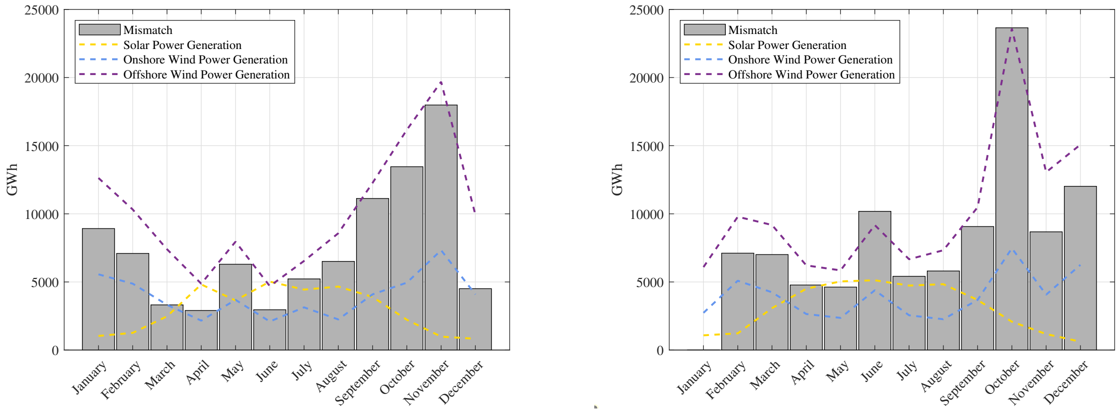


Figure 4.7: Monthly Energy Security: The Pareto Front following "Onshore Limitations" Scenario

Assessing a fixed load percentage coverage of 90%, the new onshore wind capacity constraint is strictly binding, as it lies well below the optimum of 50000+ MW onshore wind capacity, as found in the "No Preference" scenario. Therefore, the introduction of alternative VRES capacity is quickly required. The solution specifically relies upon offshore wind power generation, as this VRES can provide power generation in winter months where solar power generation is lacking. This results also in a decrease in utility-scale solar power generation, as offshore wind power generation has high production factors throughout the year. The effect of the increase in dependence on wind electricity generation can be noted in Figure 4.8, as the associated production peaks and drops are becoming more pronounced and directed by the wind power generation variations. Furthermore, as wind power generation dictates a larger portion of total power generation, the seasonal power production associated with this generation method becomes slightly visible in the mismatch graphs. Autumn and winter months generally have a higher power output than spring and summer months. Lastly, the globally binding constraint is again visible in Figure 4.8b, where a net-zero mismatch is the result of a perfect match between generation and load.

Considering that the added constraint is strictly binding, a significant increase in costs is the result, as is portrayed in Table 4.5. Offshore wind power generation is considerably more costly than its onshore counterpart and the increased capacity factor does not outweigh the added costs. However, as the increased capacity factor also holds throughout the summer months, decreased Solar PV capacity is required to provide load coverage. This cuts costs, however, the resulting VRES capacity mixture still drives up total costs, as compared to both the "No Preference" and "Onshore Opportunity" scenarios. Overall, total costs for achieving 90% load coverage in the "Onshore Limitations" scenario are increased by roughly 34 billion Euros as compared to the "No Preference" scenario., a 16% increase.



(a) Mismatch and Generation 1995 **(b)** Mismatch and Generation 2017

Figure 4.8: Monthly Mismatch and Generation Results for Two Independent Years in the "Onshore Limitations" Scenario

		90% Coverage
Onshore Limitations	Solar PV Utility (MW)	39062
	Solar PV Residential (MW)	0
	Solar PV Commercial (MW)	0
	Wind Onshore (MW)	17000
	Wind Offshore (MW)	35492
	Total Cost (bln €$_{2020}$)	241.14

Table 4.5: VRES Capacity and Costs for a "Onshore Limitations" Societal Preference Scenario

4.5 Achieving Energy Security: Offshore Focus Scenario

Finally, this section discusses the results for achieving energy security for the last societal preference scenario: the "Offshore Focus" scenario. The objective function from (18) and constraints as discussed in section 4.1 and illustrated in Table 4.1 are applied.

The Pareto Front for the "Offshore Focus" scenario shows a strong resemblance to the "Onshore Limitations" scenario Pareto Front, although having further increased total cost overall, a result of the additional constraints. The initial linear increase in costs for increased percentage load coverage remains, additionally, the costs remain to increase exponentially for the final 10% load coverage. Generally, the costs have increased upwards of 80 billion Euros, where for 100% load coverage total cost has increased close to 100 billion Euros. Therefore, it must be concluded that the strenuous constraints in the "Offshore Focus" scenario" have a severe effect on the total cost for achieving energy security.

Moving towards the single-objective optimization and fixing the percentage load coverage at 90%, the cause for the serious rise in costs can be analyzed. Most importantly, for the first time, non-utility-scale solar PV is considered for power generation. Nevertheless, it remains limited to commercial solar PV, as this is the cheaper alternative and its constraint is not yet binding. Furthermore, a strong focus on offshore wind power generation can be identified, as a result of its cost-effective coverage of load demand during winter months. Especially the peaks of wind power generation are becoming more vivid, resulting in some months with extreme surplus electricity generation. Additionally, the seasonality of wind power generation becomes more distinct, as the mismatch has become even higher. Lastly, the overall mismatch has increased across the months and years, as more redundant VRES capacity is present.

The strict constraints regarding onshore wind and utility-scale solar PV capacity, cause the

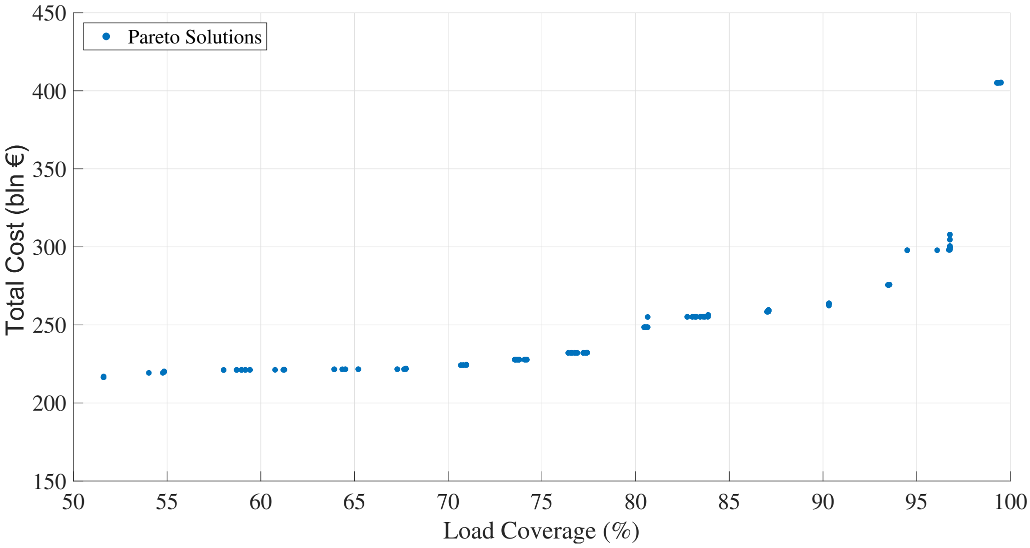
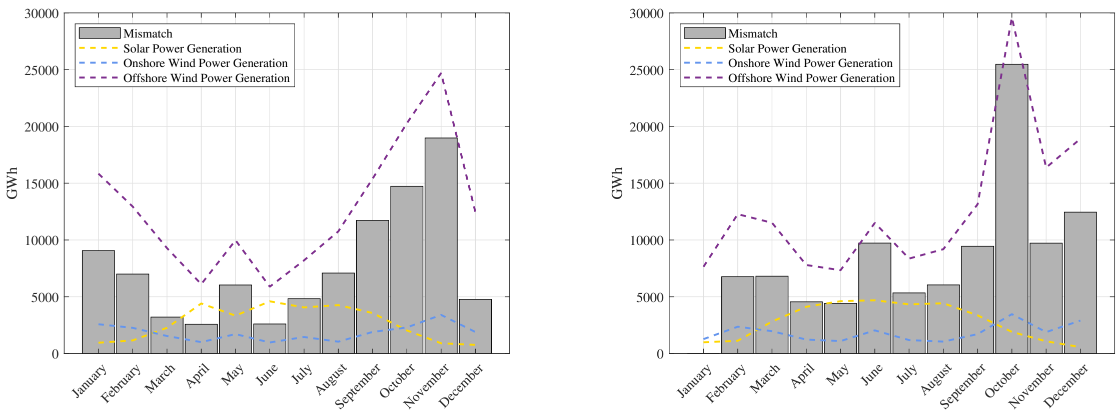


Figure 4.9: Monthly Energy Security: The Pareto Front following ”Offshore Focus” Scenario



(a) Mismatch and Generation 1995

(b) Mismatch and Generation 2017

Figure 4.10: Monthly Mismatch and Generation Results for Two Independent Years in a ”Offshore Focus” Scenario

VRES capacity mixture to be more dependent on expensive VRES such as offshore wind and commercial solar PV, as is displayed in Table 4.6. However, as offshore wind capacity is expanded, the higher capacity factor associated with this VRES results in a decreased need for solar PV capacity. This cuts some costs, however, the increased cost associated with offshore wind power generation does not outweigh this cost reduction. Therefore, the resulting increase in total cost is considerate and compared to the ”No Preference” scenario has roughly increased by 55 billion euros, a 27% increase.

		90% Coverage
Offshore Focus	Solar PV Utility (MW)	0
	Solar PV Residential (MW)	0
	Solar PV Commercial (MW)	35162
	Wind Onshore (MW)	6000
	Wind Offshore (MW)	44741
	Total Cost (bln €)	262.30

Table 4.6: VRES Capacity and Costs for a ”Offshore Focus” Societal Preference Scenario

4.6 Conclusions

This concluding section shortly discusses the relationship between load coverage and the cost, the effects of a smaller timeframe, i.e. week versus month, on the cost, and, lastly, the consequences of societal preference regarding VRES for the total cost.

Firstly, a higher percentage load coverage increases total cost, where the final ten percent of load coverage increases the cost exponentially, as more and more improbable cases are included and ought to be covered.

Secondly, a considerate difference in total cost exists between the weekly and monthly timeframe. Comparing the initial optimization results, the total cost more than doubles from 207 to 527 billion Euros, as achieving weekly energy security strongly increases the required solar PV capacity and moderately increases Onshore and Offshore Wind capacity. Accordingly, reviewing a smaller timeframe has a considerate effect on the total cost of the system, which is caused by renewable energy generation scarce weeks.

	Month (bln €)	Week (bln €)
”No Preference”	206.91	526.82
”Onshore Opportunities	223.69	-
”Onshore Limitations”	241.14	-
”Offshore Focus”	262.30	-

Table 4.7: Overview of Total Cost per Secenario and Timeframe

Thirdly, applying societal preference scenarios to the weekly and monthly timeframe influences the results substantially, as illustrated in Table 4.7. To achieve monthly energy security an increase in costs of up to 27% is concluded. Moreover, it is concluded that **no** weekly energy security can be achieved when societal preference regarding VRES is taking into consideration, as the required VRES capacity greatly exceeds the available area for VRES power generation.

In short, although energy security can be achieved in some scenarios, the total cost, especially in achieving weekly energy security, is significant. These high costs are a direct result of the variable nature of weather, which cause weeks and months with limited renewable energy generation that require additional VRES capacity to ensure load coverage. Hence, it is highly questionable whether a solution exclusively using VRES is an option to provide energy security in the future.

5 Achieving Energy Security Using VRES and Long-Term Hydrogen Storage

Available VRES capacity is utilized more effectively whenever storage technologies are available, as this will provide an opportunity for shifting surplus electricity throughout the year, reducing curtailment needs. This leads to a decreased need for VRES capacity, lowering costs and potentially overall costs for achieving energy security. However, as of yet, storage technologies are generally perceived as expensive and the question remains whether their introduction in the energy system is a cost-effective method in achieving energy security. This chapter reviews their introduction in the energy system and analyzes the cost-effectiveness of a long-term energy storage system in achieving weekly and monthly energy security. A number of pathways are discussed and the optimal solution is reviewed for a number of scenarios, including the societal preference scenarios discussed in Chapter 4. Lastly, apart from the two timeframes considered, weekly and monthly, the 31-year period is both considered as a whole, allowing for inter-annual storage, as well as separately, where thus energy security must be achieved individually each year and no option for inter-annual storage exists.

Section 5.1 introduces the various scenarios and optimization problems applied in this chapter. Section 5.2 discusses the results for achieving energy security individually each year, taking a weekly and monthly timeframe and various societal preference scenarios into consideration. Section 5.3 evaluates the results for achieving energy security over the 31-year period as a whole, taking a weekly and monthly timeframe and various societal preference scenarios into consideration. Finally, Section 5.4 concludes on the cost-effectiveness of long-term storage, considering the various scenarios, timeframe effects, and the allowance for inter-annual storage.

5.1 Introducing Storage to the Various Scenarios and their Optimization Problems

This section discusses the optimization problems applied in this chapter, which enable the solving algorithm to find the most cost-effective solution for achieving energy security in a number of scenarios. Similar to Chapter 4, both a multi-objective (MOGA) and a single-objective solving algorithm (GA) are used. The MOGA helps to find the ”Pareto Front” for a varying load coverage percentage, while a more accurate in-depth solution is found using a GA for a fixed load percentage (90% load coverage). As was explained in-depth in Chapter 4.1, the percentage load coverage reflects the number of years in the 31-year period, for which load demand must be met. In total six pathways, as determined in literature review and summarized in Table 2.10, are evaluated, however, not all are assessed for the scenarios in this chapter. From the initial Pareto Front the most optimal pathway is selected and, thereafter exclusively used to review the impact of the various scenarios. The less relevant results for all other pathways are provided in Appendix B. The evaluated scenarios for societal preference remain as determined in Chapter 4.1. Moreover, the scenarios are still assessed for both a weekly and monthly timeframe.

However, as storage now is introduced to the optimization problem, the 31-year period can be reviewed in two additional ways, either altogether or as individual years. In other words, inter-annual storage is either possible or impossible. Reviewing the 31-year period altogether effectively takes only one data point as the entry for the optimization problem. Therefore, the results, although providing interesting insight into inter-annual behaviour of the storage facility, technically only provide energy security whenever weather events occur as how they exactly occurred between 1988-2018, and thus do not necessarily apply to any future weather profiles. In other words, potentially the solution found only ensures energy security between 1988 and 2018. Therefore, to acquire more general results, the 31-year period is split into separate years and inter-annual storage is not possible. Effectively this creates 31 data sets, which provide independent results, generalizing the overall result and making it more robust concerning future weather circumstances.

In the next two sections, the optimization problems for these two approaches are discussed, introducing the objective functions, as well as the linear and non-linear constraints.

5.1.1 The Optimization Problem: Without Inter-Annual Storage

Firstly, the objective function is determined. The introduction of the storage facility adds several new components that can help to achieve energy security but also have an effect on the total cost. Therefore, the objective function is considerably expanded;

$$f(P_{sol}, P_{on}, P_{off}, P_{dis}, P_{ch}, E_{st}) = C_{solu} \cdot P_{solu} + C_{res} \cdot P_{res} + C_{com} \cdot P_{com} + C_{on} \cdot P_{on} + C_{off} \cdot P_{off} + C_{dis} \cdot P_{dis} + C_{ch} \cdot P_{ch} + C_{st} \cdot E_{st} \quad (19)$$

Here all power capacities ($P_{solu}, P_{res}, P_{com}, P_{on}, P_{off}, P_{dis}$, and P_{ch}) are given in MW, while the associated costs are in €/MW. The energy storage (E_{st}) is in GWh and its associated costs in €/GWh.

The solving algorithms are tasked to find a minimal cost solution, for a range of load coverage percentages. The power capacities ($P_{solu}, P_{res}, P_{com}, P_{on}, P_{off}, P_{dis}$, and P_{ch}) from (**??**) are variables. Achieving load coverage, without inter-annual storage, is here discussed for both a weekly and monthly timeframe. Achieving load coverage is considered a non-linear constraint, as it only applies for a percentage of the years from the 31-year load. Load coverage can be achieved in a number of ways, including the utilization of the storage facility. First of all, load demand, which is still based on the load profile determined in Chapter 3.5 and 3.6 for the monthly and weekly timeframe respectively, can be met through abundant VRES power generation. The VRES power generation is calculated using the variables from (**??**) applied to (11) and (16) for the monthly and weekly timeframe respectively.

In periods with bad weather circumstances and thus limited renewable power generation, negative mismatches could occur if not enough VRES capacity is available. Instead of expanding VRES capacity to achieve energy security, load demand can partially be met through energy supply from the storage facility. If both adequate energy storage and discharging capacity are available, a negative mismatch can be (partially) covered without requiring further expansion of the VRES capacity. However, it must be noted that the storage facility is to be adequately charged to provide load coverage during these periods of shortage. In this scenario, where inter-annual storage is not possible, it is required that the storage facility is charged equally or more than the amount of energy discharged from the storage facility during that specific year, ensuring adequate available energy. The discharging capacity (P_{dis}) is determined by evaluating the largest negative mismatch effectively covered by said discharging capacity. Assessing the charging capacity (P_{ch}) is slightly more complicated, as not all surplus energy is necessarily stored. Therefore, it is assessed per year what charging capacity is required to store adequate energy using all weeks/months with surplus energy. Finally, the total storage capacity (E_{st}) is determined by evaluating the discharging and charging of the storage capacity, where the most extreme year determines the required total capacity to provide energy security. Lastly, it is assumed that, prior to the 31-year evaluated period, the storage facility is completely charged. This assumption allows the enforced charging of the storage facility also to occur after it has been discharged, allowing for discharging of the storage facility in the first week/month of each year. It is most important to note that the optimization problem does **not** enforce the utilization of the storage facility, thus, allowing the solving algorithms, both MOGA and GA, to find the most optimal solution either including or excluding storage.

Apart from these non-linear constraints for achieving load coverage, linear constraints, representing various societal preference scenarios, exist. These constraints are equal to the scenarios discussed in Chapter 4.1, which provides an in-depth explanation of these constraints, and limits VRES capacities according to societal preference. Table 5.1 provides a summary of the constraints, where the "No Preference" scenario is not constrained in any way.

	No Preference	Onshore Opportunities	Onshore Limitations	Offshore Focus
Solar PV (utility-scale)	-	$\leq$ 150 GW	$\leq$ 150 GW	0
Solar PV (residential)	-	$\leq$ 93.8 GW	$\leq$ 93.8 GW	$\leq$ 93.8 GW
Solar PV (commercial)	-	$\leq$ 54.9 GW	$\leq$ 54.9 GW	$\leq$ 54.9 GW
Wind Onshore	-	$\leq$ 50 GW	$\leq$ 17 GW	$\leq$ 6 GW
Wind Offshore	-	11-60 GW	11-60 GW	11-60 GW

Table 5.1: Overview of Constraints representing Societal Preference Scenarios

5.1.2 The Optimization Problem: Inter-Annual Storage

The optimization problem for this approach remains mostly similar as in Section 5.1.1. The objective function and linear constraints, representing the societal preference scenarios, remain unchanged and are thus represented by (19) and Table 5.1 respectively. Furthermore, VRES power generation and the load profile are calculated as before, for both the weekly and monthly timeframe. However, the non-linear constraints are slightly adjusted to reflect the new approach in calculating results for the 31-year appropriately.

The storage facility remains to potentially play an important role in covering load demand, however, two of the capacities associated with the storage facility (P_{ch} and E_{st}) are determined differently. The discharging capacity (P_{dis}) remains to be calculated by evaluating the largest negative mismatch, in the years that add to the percentage load coverage, effectively covered by said discharging capacity. As energy stored in 1988 is potentially available in 2018, the charging capacity must be determined over a longer period. As before, not all surplus energy generation is necessarily stored to achieve energy security. The charging capacity (P_{ch}) is determined based on the premise that the no negative energy storage is allowed. If negative energy storage is observed by the solving algorithm, this can be caused by three shortcomings, which require an adjustment of the results. First, potentially too little VRES capacity is available, resulting in too many periods of negative mismatch and thus a drained storage facility. Secondly, the storage capacity is not adequately sized and can not coop with prolonged periods of shortage. Lastly, the charging capacity is not sufficiently sized, resulting in no adequate storage of surplus energy generation in the storage capacity. Generally, a mixture of these three shortcomings cause a negative storage level. Finding such a failure, the solving algorithm adjusts the capacities, eventually moving towards a correct solution and thus finding the appropriate charging capacity. The final total required storage capacity is calculated by assessing the maximal storage level that is acquired and required during the 31-year period. Lastly, in contrast to the approach in section 5.1.1, the storage facility is not charged prior to the 31-year period. All stored and consumed energy is generated within the 31-year timeframe.

5.2 Achieving Energy Security without Inter-Annual Storage

In this section, first achieving monthly energy security, with each year examined separately, is considered. The Pareto Fronts for all six different pathways are provided, after which the most cost-effective pathway is determined and further analyzed for the societal preference scenarios. Thereafter, also for a weekly timeframe results are gathered and analyzed. Lastly, the results for the various scenarios and timeframes are compared, to draw conclusions on their effects.

5.2.1 Achieving Monthly Energy Security

Figure 5.1 portrays the Pareto Fronts for all pathways, as determined in Chapter 1.5. From the Pareto Fronts we can draw several conclusions. First of all, introducing energy storage reduces overall costs considerably on the complete range of load percentage coverage. Furthermore, a much slower increase in cost for the top load coverage percentage as compared to Figure 4.1 is notable. Generally, the availability of energy storage allows for much more cost-effective load coverage, as inefficient VRES capacity oversizing is not necessary. Load demand in months with below average power generation, due to e.g. low wind speeds or limited solar irradiance, is much more cost-effectively met using hydrogen storage. Therefore, the available VRES capacity is much more effectively used, and curtailing is effectively reduced. Consequently, redundant VRES capacity is reduced, decreasing costs significantly for all load-percentage coverage analyzed. In conclusion, long-term storage allows for much more cost-effective monthly energy security.

Secondly, costs increase highly linear for rising load coverage percentage, however, for the final 10% load coverage a more exponential increase in costs observed, as was similarly observed for the exclusive VRES approach. As more and more improbable situations are to be included to achieve a high load percentage coverage, costs rise more sharply. In other words, the last 10% load coverage requires the incorporation of years with extreme weather conditions, e.g. generally little wind or solar irradiance, to be covered. Including these more improbable weather circumstances in the solution, drives up the total VRES capacity requirement, as the below average power generation in those years must be compensated by increasing capacity of the VRES and storage facility. This results in predominantly redundant VRES capacity and some redundant, which is only used in a few (or one) specific year but curtailed in all others. This is a costly singular investment and increases costs significantly. An alternative to VRES capacity expansion is an increase in charging, discharging and storage capacity, to store and distribute energy from the few surplus months in an extreme year more effectively. However, this also remains to be a highly costly investment, as much of added storage facility capacity also remains unused in all other years.

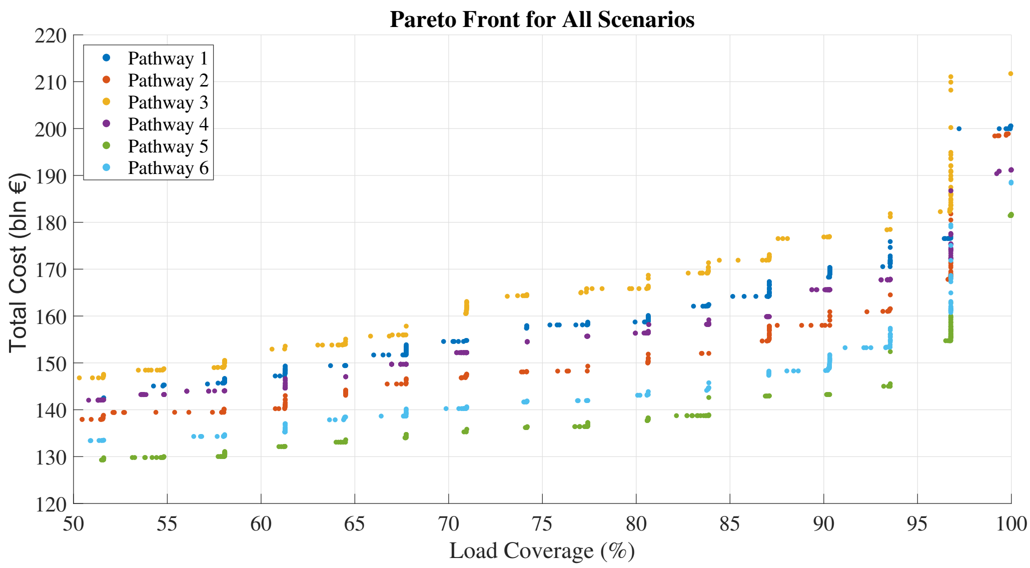


Figure 5.1: Monthly Energy Security Without Inter-Annual Storage: Pathways Total Cost Pareto Fronts

Determining the most cost-effective pathway is easily done using Figure 5.1. Over the entire load percentage coverage range Pathway 5, which uses AEL and Hydrogen CCGT, is the most cost-effective solution. This is the expected result, as these technologies both have the highest efficiency as well as lowest cost of all electrolysis and reconversion technologiesdiscussed. Therefore, for **all** other scenarios (and timeframes) considered in this chapter, *AEL and Hydrogen CCGT* are used for electrolysis and reconversion respectively.

Introducing the societal preference scenarios constraints has considerable effect on the total cost Pareto Front, as is illustrated in Figure 5.4. The Pareto Front increases between 10 and 40 billion Euros, as compared to the "No Preference" scenario, depending on the load coverage percentage reviewed. This increase in cost is directly caused by the additional constraints, which is visualized in the 90% load coverage scenario. The total cost Pareto Front for both the "Onshore Opportunities", as well as the "Onshore Limitations" scenario are highly similar, showing only a considerable difference at 100% load coverage. This indicates that the constraints for "Onshore Limitations" are strictly binding only at 100% load coverage. Interestingly, the total cost difference between the societal preference scenarios and the base case decreases when 100% load coverage is analyzed. This behaviour is explained as the societal preference scenarios are much less dependent on onshore wind energy, but instead focus more on offshore and solar power generation, two technologies which have a considerably lower standard deviation for power output.

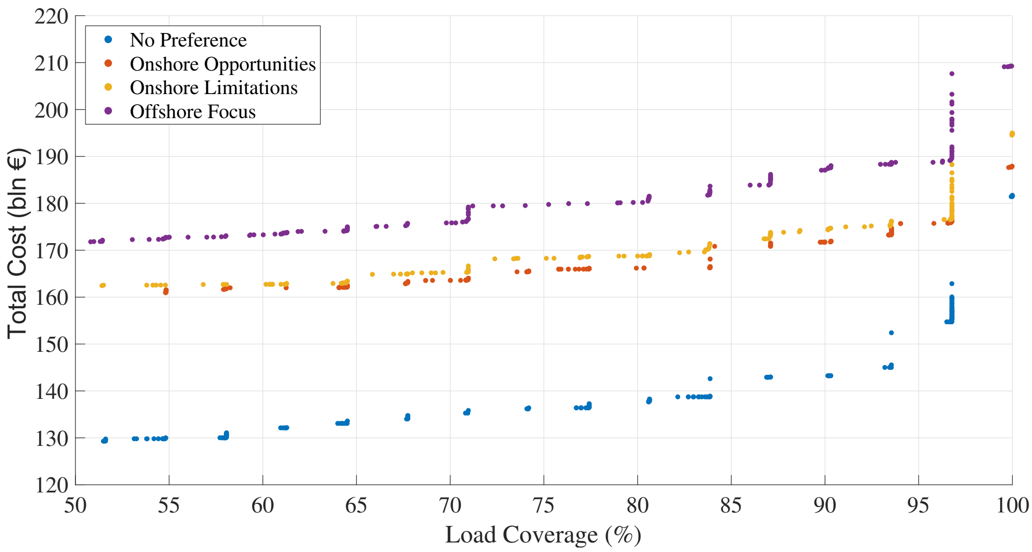


Figure 5.2: Monthly Energy Security Without Inter-Annual Storage: Scenarios Total Cost Pareto Fronts

To review the VRES and storage facility capacities more closely, the fixed 90% load coverage results are reviewed, which are illustrated in Figure 5.3. First of all, the importance of long-term hydrogen storage should be addressed. As was concluded from the decrease in total cost of the Pareto Front, long-term hydrogen storage is an essential sub-part for achieving monthly energy security. The storage capacity is roughly equal to a single month of load demand. Moreover, it remains to play an important role, also when various societal scenarios are considered. Considering the significant storage capacity required for all solutions it should be remarked that there is ample space in the Netherlands for hydrogen storage in salt caverns. As was concluded in Chapter 2.3.1 up to 43000 GWh of hydrogen storage could be created, covering the required capacity for all pathways easily [66].

The significant storage capacity enables the redistribution of the main power generation method in the "No Preference" scenario: onshore wind. Onshore wind plays such a dominant factor as it is much cheaper per MW and eventually per generated MWh than all other VRES technologies. Furthermore, solar power production also takes on a considerate capacity in all scenarios, as this method can provide cost-effective power production during the summer months. Therefore, solar PV is a perfect supplement to the low power production summer months of onshore wind energy.

The optimal solution for the ”Onshore Opportunities” scenario is characterized by the binding constraint of 11 GW of offshore wind. Although more onshore wind capacity is allowed, the requirement for offshore wind decreases the need for onshore wind power generation and increases costs, as offshore wind capacity is roughly twice as expensive per MW. Additionally, a decrease in charging and discharging capacity, as compared to the ”No Preference” scenario is noted. Due to the stronger dependence on a low standard deviation power production, generally, more months with surplus power generation occur, therefore, requiring less peak charging of the storage capacity. For similar reasons, the discharging capacity decreases slightly.

In the second societal preference scenario ”Onshore Limitations”, the onshore wind capacity constraint becomes binding. Therefore, further dependence on solar PV capacity is observed, while also offshore wind capacity is expanded. Cost-effective utility solar PV capacity predominantly covers power generation during summer months. Where high capacity factor offshore wind and onshore wind can provide ample energy to cover load demand during winter months. A further decrease in charging and discharging capacity is observed, as the VRES capacity mixture further moves towards less fluctuating power sources. Additionally, storage capacity decreases slightly, however, this is not a congruent result. Performing the optimization a number of times provides results for storage capacities that are mostly similar to the other societal preference scenarios. Higher storage capacities usually slightly decrease VRES capacity results, but have no effect on the total cost.

Lastly, the ”Offshore Focus” scenario shows the strongest effect of the societal constraints regarding VRES capacity. Most importantly, for the first time, commercial solar PV capacity is introduced in the VRES capacity mixture. The limiting constraint on utility-scale solar PV forces the solving algorithm to find an alternative for this power generation method. To replace this capacity, commercial solar PV is used, as this is apparently a more cost-effective solution than increasing the storage facility capacity or offshore wind capacity. Charging and discharging capacity remain smaller than the results from the ”No Preference” scenario, as the VRES capacity mixture continues to be dependent on sources with a lower standard deviation for power generation.

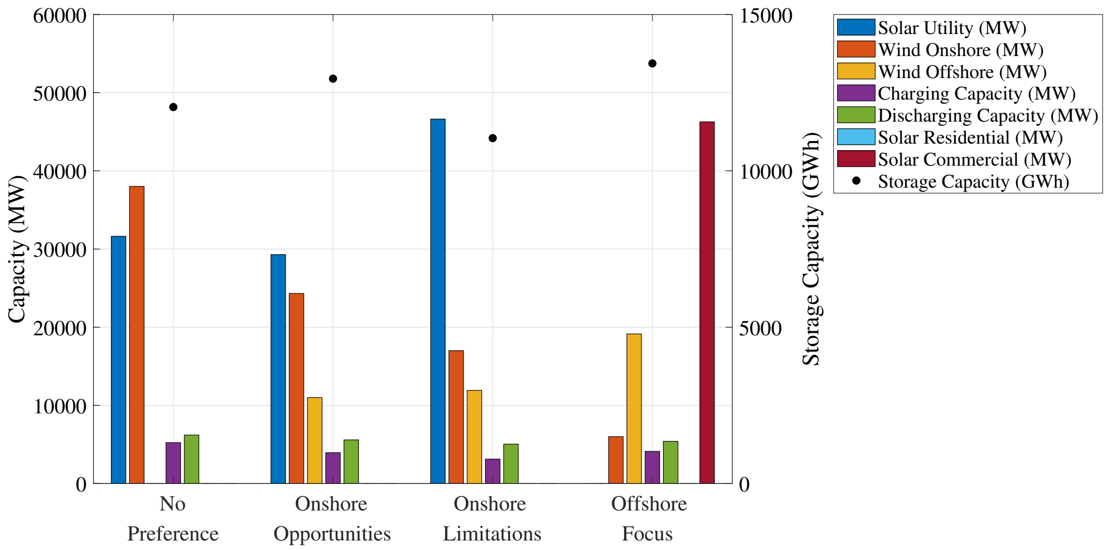


Figure 5.3: Monthly Energy Security Without Inter-Annual Storage: Societal Scenarios Capacity Results 90% Load Coverage

Table 5.2 provides the numeric overview of the various capacities displayed in Figure 5.3. Moreover, the total cost for the optimal solutions are presented. As indicated by the Pareto Fronts, societal constraints on VRES capacity results in additional costs to achieve monthly energy security. The total cost roughly increase between 10% and 30% for the various societal preference scenarios, as compared to the ”No Preference” scenario. However, the increase in costs for the ”Onshore Opportunities” and the ”Onshore Limitations” scenario are almost equal. Thus the further constraint have no influence on the total cost, even though the results are affected. A more significant increase becomes apparent for the more restricting ”Offshore Focus” scenario. Nevertheless, although percentile increase is similar, the absolute increase in costs is much less compared to the exclusive VRES solution cost development for the various societal preference scenarios. In conclusion, also when societal preference regarding VRES capacity is taken into account, long-term hydrogen storage provides a much more cost-effective solution than a sole VRES solution, decreasing cost by roughly 35%.

	No Preference	Onshore Opportunities	Onshore Limitations	Offshore Focus
Total Cost (bln €)	139.17	154.61	155.95	176.67
Storage Capacity (GWh)	12041	12949	11046	13436
Solar PV Utility (MW)	31634	29286	46623	0
Solar PV Commercial (MW)	0	0	0	46272
Solar PV Residential (MW)	0	0	0	0
Wind Onshore (MW)	38012	24318	17000	6000
Wind Offshore (MW)	0	11000	11919	19137
Charging Capacity (MW)	5239	3954	3128	4117
Discharging Capacity (MW)	6210	5589	5044	5404

Table 5.2: Monthly Energy Security Without Inter-Annual Storage: Societal Scenarios Cost and Capacity Overview 90% Load Coverage

5.2.2 Achieving Weekly Energy Security

The Pareto front, as depicted in Figure 5.4 for weekly energy security indicates a significant increase in total cost for all scenarios, as compared to the monthly timeframe. In a weekly timeframe more periods of shortage have become visible. In a monthly timeframe reduced power production for specific weeks within the month are averaged out, making the overall power production below average but reducing extreme outliers. However, these extreme weeks, with e.g. no/low wind speeds and solar irradiance, have become apparent in the weekly timeframe. Therefore, to meet load demand, either VRES power production must increase, or a storage facility must be adequately sized. These alterations, as compared to the monthly timeframe, cause additional cost and move the Pareto Front up. The Pareto Front for the various scenarios, increases roughly between ten to thirty billion Euros. Generally, lower percentage coverage allows the total cost for the various scenarios to be more similar, however, the ”Offshore Focus” scenario remains to be considerably more expensive than the ”No Preference” scenario due to the strict constraints. Nevertheless, the results are highly **supportive** of the implementation of the long-term hydrogen storage, as compared to an exclusive VRES solution, which roughly tripled in cost.

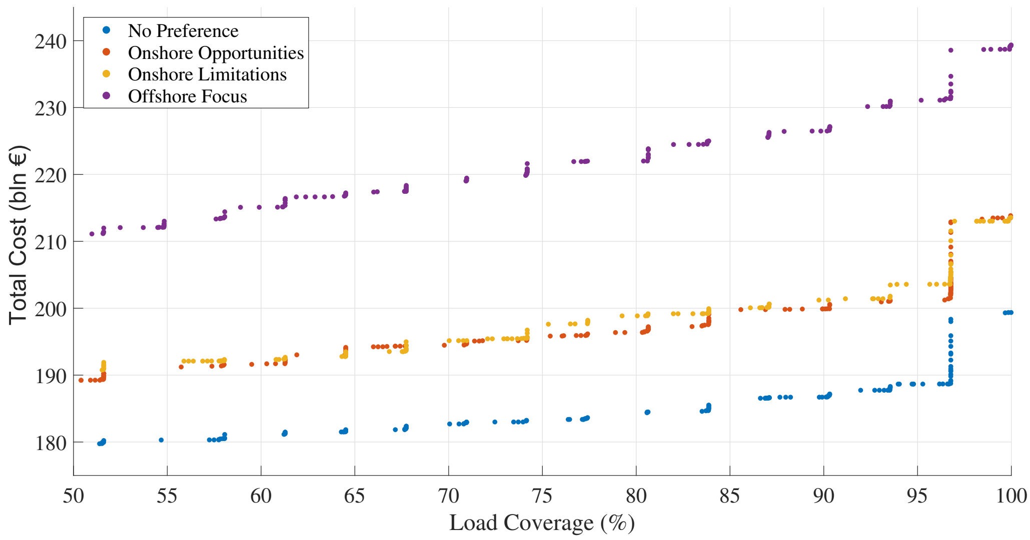


Figure 5.4: Weekly Energy Security Without Inter-Annual Storage: Scenarios Total Cost Pareto Fronts

To review the effect of a weekly timeframe more accurately, the results for a fixed load percentage (90%) are shown in Figure 5.5. A general significant increase in VRES, storage, charging, and discharging capacity can be noted for all scenarios, as was expected based on the Pareto Front. The periods of shortage increase the need for generation and storage facility capacity to ensure load coverage.

The ”No Preference” scenario remains to be dependent on onshore wind energy, however, compared to the monthly timeframe, the capacity is roughly halved. This is compensated by a doubling in solar PV capacity. Solar PV becomes the favoured VRES, as the standard deviation for power generation through this method is much less, meaning a more stable weekly power generation. Therefore, much less weeks with extreme scenarios exists, making the VRES much more reliable for load demand coverage. Nevertheless, onshore wind energy is required for load demand coverage in the winter months. However, to ensure load demand coverage using such a fluctuating VRES, the storage, charging, and discharging capacities need to be considerably increased. In fact, the capacities are roughly doubled, indicating the very important role the storage facility plays in the weekly timeframe. This behaviour holds for **all** scenarios.

Secondly, the ”Onshore Opportunities” scenario is again required to have the 11 GW offshore wind capacity. This enforced capacity reduces onshore wind capacity, as it is predominantly used during the winter months. Furthermore, as offshore wind power generation fluctuates less than onshore wind generation, the storage capacity is slightly decreased. Discharging capacity remains similar to the ”No Preference” scenario, as it remains vital to provide load coverage in the winter months. However, due to the stronger dependence on VRES capacity with a lower standard deviation for power generation, weeks with surplus energy generation occur more often, thus reducing charging capacity necessity.

Thirdly, in the ”Onshore Limitations” scenario the dependence on solar PV capacity is increased, and consequently a decreases of onshore wind capacity occurs. The stronger dependence on this strongly seasonally bound generation method is reflected in the increased storage capacity and charging capacity. Offshore wind capacity remains to be expensive and thus not cost-competitive to the alternatives of utility-scale solar PV and onshore wind, however, due to the 11 GW constraint, the minimal required capacity is included in the results.

Lastly, the ”Offshore Focus” scenario shows a strong dependence on offshore wind energy. The limiting constraints regarding utility-scale solar PV, commercial solar PV and onshore wind capacity are the direct cause for the high costs associated with this societal preference scenario. It is interesting to note that no residential solar PV is introduced in the VRES capacity mixture, as this is apparently not cost-competitive with offshore wind energy. The increased dependence on offshore wind energy, a VRES with low standard deviation power generation, causes the decreased storage capacity.

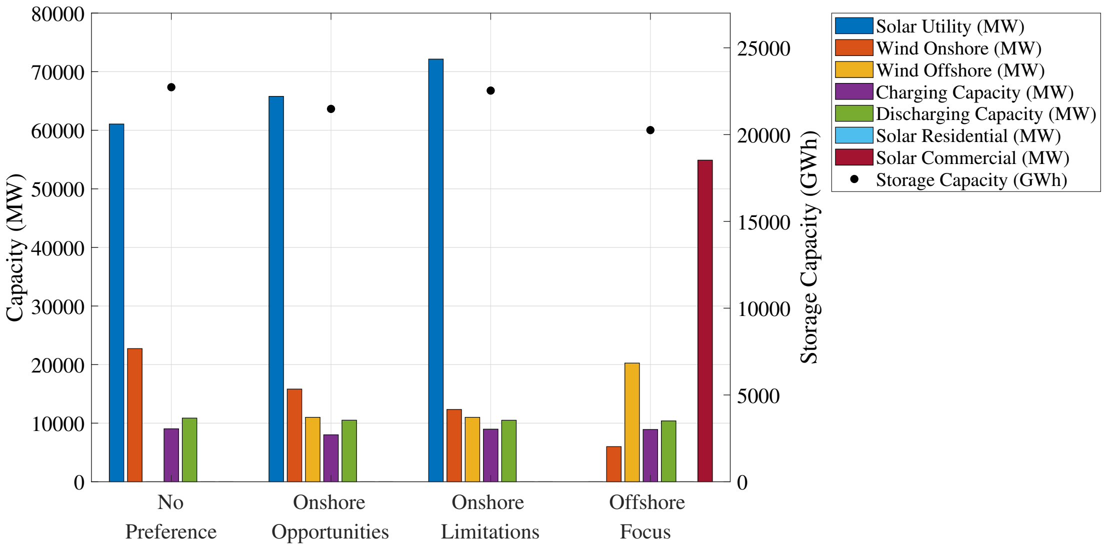


Figure 5.5: Weekly Energy Security Without Inter-Annual Storage: Societal Scenarios Capacity Results 90% Load Coverage

As shown in Table 5.3 the total costs for the societal preference scenarios have increased significantly, as compared to the "No Preference" scenario, between 20-25%. The predominant increase in cost is caused by the doubling of the charging, discharging and storage capacities. However, the additional VRES capacity also adds significantly to the cost increase. Nevertheless, where in the monthly timeframe total costs are heavily determined by the VRES capacities, the storage facility now has a much more significant contribution. Furthermore, limited differences remain to exist between the "Onshore Opportunities" and "Onshore Limitations" scenario, as the costs remain highly similar. The high similarity in cost for these two scenarios, and the slight changes in VRES and storage facility capacity mixture indicate that more solutions, which are either slightly more dependent on onshore wind energy or solar PV capacity, have highly similar total costs.

Comparing the long-term hydrogen storage "No Preference" scenario total costs to the costs, as found for the exclusive VRES approach, a 73% decrease is observed. This result emphasizes the necessity for storage in achieving energy security in the future energy system.

	No Preference	Onshore Opportunities	Onshore Limitations	Offshore Focus
Total Cost (bln €)	173.84	187.98	188.65	211.04
Storage Capacity (GWh)	22731	21481	22536	20259
Solar PV Utility (MW)	61086	65788	72151	0
Solar PV Commercial (MW)	0	0	0	54900
Solar PV Residential (MW)	0	0	0	0
Wind Onshore (MW)	22731	15822	12339	6000
Wind Offshore (MW)	0	11000	11000	20424
Charging Capacity (MW)	9044	8019	8982	8923
Discharging Capacity (MW)	10869	10509	10501	10388

Table 5.3: Weekly Energy Security Without Inter-Annual Storage: Societal Scenarios Cost and Capacity Overview 90% Load Coverage

5.3 Achieving Energy Security Allowing Inter-Annual Storage

Considering the 31-year period as a whole potentially leads to alternative solutions, as inter-annual storage might lead to a different use of the storage facility. However, due to the limited available data, essentially N = 1, no strong conclusions can be drawn. Nevertheless, the results do provide an indication on how inter-annual storage affects VRES and storage facility capacity sizing.

5.3.1 Achieving Monthly Energy Security

The Pareto Fronts, shown in Figure 5.6, have slightly decreased in costs over the entire load percentage coverage. However, the decrease in cost is minimal, requiring an in-depth review at a fixed load percentage allows to discuss this decrease in cost more closely. Regardless of the approach the costs remain to increase linearly with rising load percentage coverage, and finally increase more considerably when load coverage in all 31 years is provided.

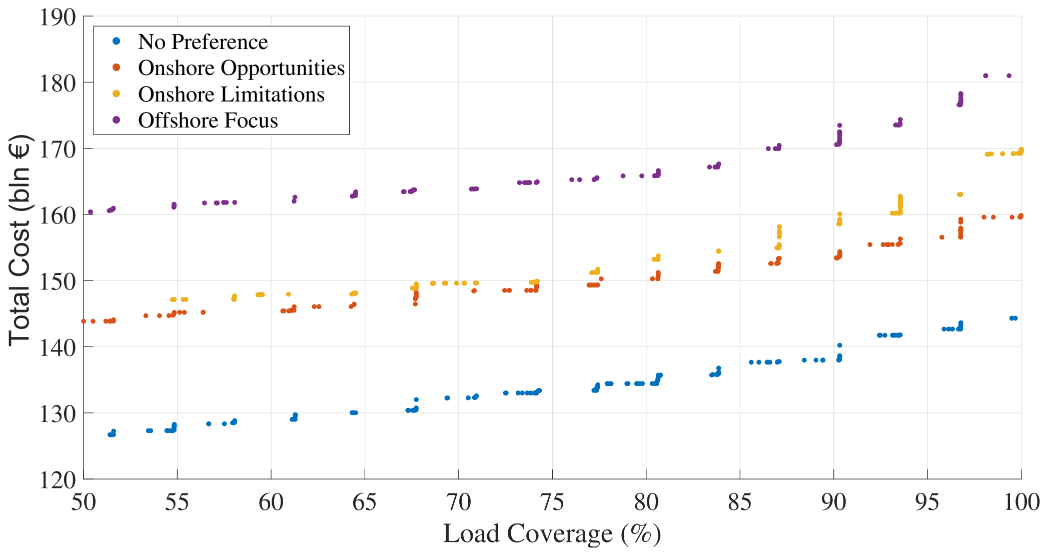


Figure 5.6: Weekly Energy Security Inter-Annual Storage: Scenarios Total Cost Pareto Fronts

In general, how the various scenarios affect the results remains highly similar as was observed in Figure 5.3. However, the individual results per scenario have quite interestingly changed, as is depicted in Figure 5.7. Generally, VRES capacities have decreased, although the ratios between the various sources have remained similar. However, storage capacity has roughly doubled for all scenarios. This strong increase in storage capacity explains the decrease in VRES capacity, as more surplus generated power can be stored and thus longer periods of shortage can be covered. Due to the potential for inter-annual storage, extending storage capacity has become a cost-effective approach for meeting load demand in the few specific years with extreme weather conditions. Importantly, no significant increase of charging capacity is required, as the storage facility can be slowly charged over multiple years and still cover extreme cases in singular years. Therefore, making the storage approach for these specific scenarios much cheaper and thus the preferred method. Therefore, allowing inter-annual storage has a considerate effect on the resulting VRES and storage capacities.

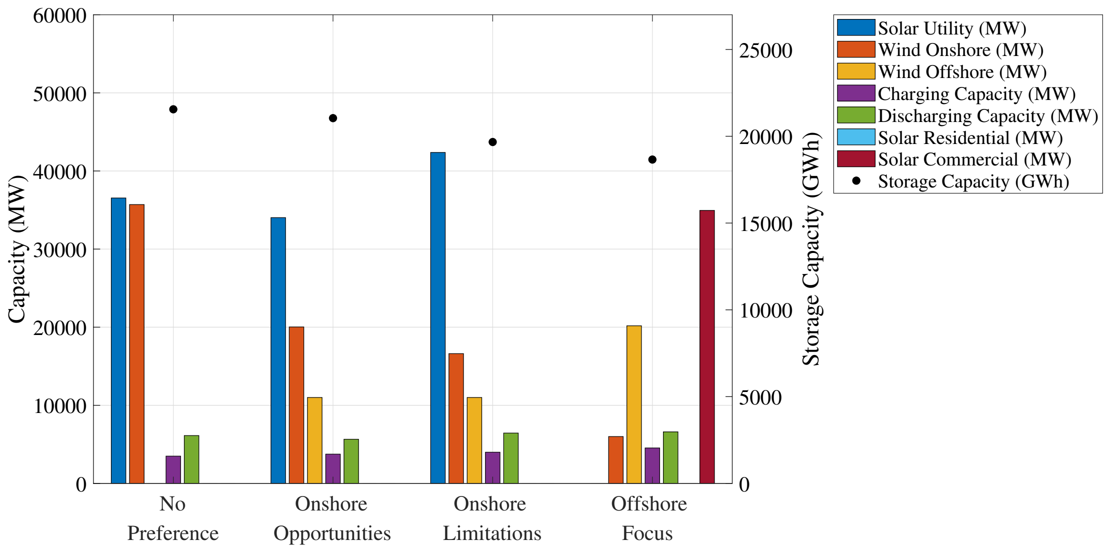


Figure 5.7: Monthly Energy Security Inter-Annual Storage: Societal Scenarios Capacity Results 90% Load Coverage

Table 5.4 portrays a numeric overview of the results as illustrated in Figure 5.7. Interestingly, the new approach hardly affects the total cost, decreasing it maximally by roughly 2%. Accordingly, it is concluded that the alternative approach of assessing the period as a whole, does not considerably affect the results for the monthly timeframe. Consequently, the more robust solutions provided in Chapter 5.2 should be leading.

	No Preference	Onshore Opportunities	Onshore Limitations	Offshore Focus
Total Cost (bln €)	139.24	152.48	153.88	172.07
Storage Capacity (GWh)	21554	21044	19669	18658
Solar PV Utility (MW)	36542	34029	42370	0
Solar PV Commercial (MW)	0	0	0	34591
Solar PV Residential (MW)	0	0	0	0
Wind Onshore (MW)	35701	20031	16616	6000
Wind Offshore (MW)	0	11000	11000	20181
Charging Capacity (MW)	3493	3748	3994	4538
Discharging Capacity (MW)	6125	5652	6445	6599

Table 5.4: Monthly Energy Security Inter-Annual Storage: Societal Scenarios Cost and Capacity Overview 90% Load Coverage

5.3.2 Achieving Weekly Energy Security

The Pareto Fronts, as illustrated in Figure 5.8, show a slight decrease in total cost across all scenarios. Nevertheless, both the ”Onshore Opportunities” and ”Onshore Limitations” scenario remain closely comparable in cost. Furthermore, total costs remain to rise linearly with increasing load percentage coverage, and increase considerably to provide load coverage when the most improbable weather circumstances are included.

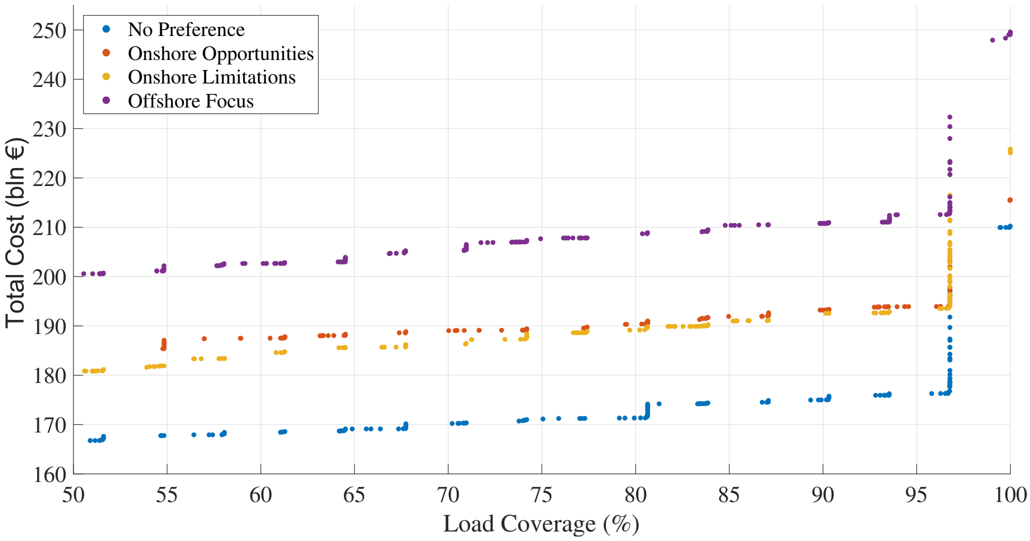


Figure 5.8: Weekly Energy Security Inter-Annual Storage: Scenarios Total Cost Pareto Fronts

As was observed for the monthly timeframe, the capacity mixture relies more on the storage capacity for achieving energy security, as is illustrated in Figure 5.9. However, no doubling in capacity is observed, as the storage capacities were already significantly sized for the no inter-annual storage results. Moreover, a move towards onshore wind energy and away from solar PV capacity is observed. Inter-annual storage allows for an energy system more reliant on more heavily fluctuating power sources, as the storage capacity can be filled over a larger period. Therefore, allowing inter-annual storage has a considerate effect on the resulting VRES and storage capacities.

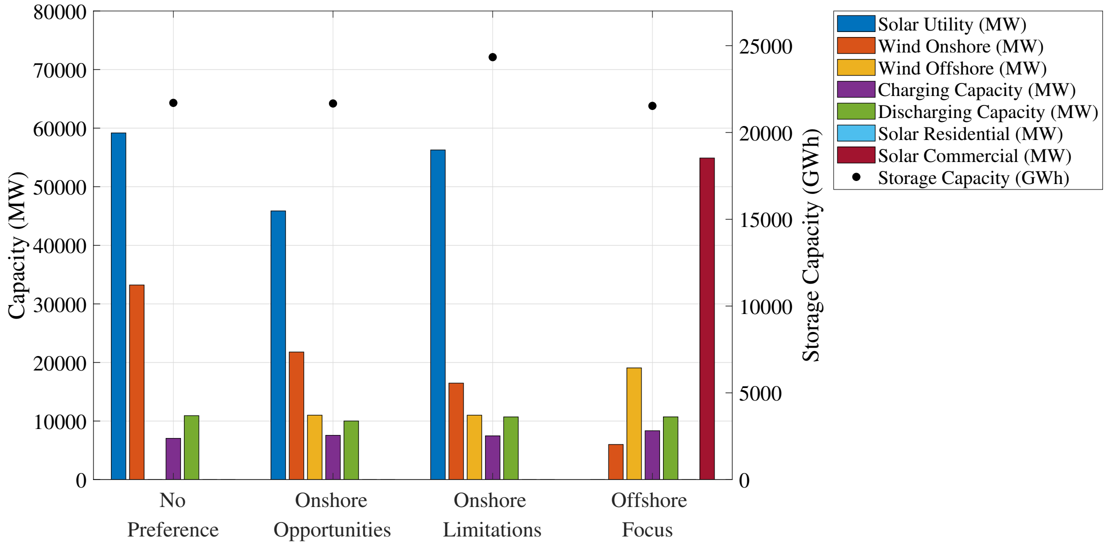


Figure 5.9: Weekly Energy Security Inter-Annual Storage: Societal Scenarios Capacity Results 90% Load Coverage

Table 5.5 provides an overview of the capacities and total cost of the various scenarios. Comparing the costs to results found for the weekly timeframe in section 5.2, a decrease of roughly 5% is observed. Therefore, it must be concluded, although capacity results differ, that no significant effect on total cost is the result. Moreover, it should be stressed that these results provide a specific solution over the period 1988-2018, and thus provide no guarantee of success in future weather scenarios. Therefore, the more robust results from Chapter 5.2 are to be leading when designing the future energy system of the Netherlands.

	No Preference	Onshore Opportunities	Onshore Limitations	Offshore Focus
Total Cost (bln €)	168.41	180.35	180.45	200.37
Storage Capacity (GWh)	21706	21671	24341	21533
Solar PV Utility (MW)	59179	45869	56276	0
Solar PV Commercial (MW)	0	0	0	54900
Solar PV Residential (MW)	0	0	0	0
Wind Onshore (MW)	33224	21783	16474	6000
Wind Offshore (MW)	0	11000	11000	19071
Charging Capacity (MW)	7047	7567	7476	8348
Discharging Capacity (MW)	10919	10009	10705	10713

Table 5.5: Weekly Energy Security Inter-Annual Storage: Societal Scenarios Cost and Capacity Overview 90% Load Coverage

5.4 Conclusions

In conclusion, both weekly and monthly energy security are reached much more cost-effectively using long-term hydrogen storage compared to a sole VRES solution. Costs drop significantly for all discussed scenarios, and are halved and more than halved compared to the sole VRES equivalent, for the monthly and weekly timeframe respectively. Additionally, without inter-annual storage, although costs increase compared to allowing inter-annual storage results, still results in a more cost-effective solution for weekly and monthly energy security compared to an exclusively VRES based solution. However, inter-annual storage results remain an indication, as these results are based on a single data entry thus limiting their applicability in alternative scenarios. The most cost-effective pathway for all discussed conditions is Pathway 5, which relies on long-term hydrogen storage conversion and reconversion on AEL and Hydrogen CCGT. The other pathways are mostly non-competitive due to high costs per MW for conversion and reconversion technologies, a vital factor in achieving cost-effective weekly and monthly energy security. The efficiency of the technologies does not play as a significant role, as much redundant electricity is generated. As a matter of fact, the majority of the costs, between 75-85%, is due to VRES capacity installations. When addressing societal preferences we generally see an increase in costs compared to the optimal solution. However, the increase in costs only becomes more significant for the ”Offshore Focus” scenario.

Societal preference plays an important role in determining the total cost for the found solutions. For the ”Onshore Opportunities” and ”Onshore Limitations” costs initially increase due to the offshore wind capacity requirement of 11 GW. Costs for these scenarios are highly similar when weekly and monthly energy security are being assessed. However, for the ”Offshore Focus” the costs further increase, as now an onshore wind capacity constraint of 6 GW limits cost-effective onshore wind power generation. In short, costs increase as societal constraints are considered, and thus for real-world implementation these cost estimates most likely provide a more accurate representation.

Weekly and monthly energy security results show considerable differences, as was concluded already for the sole VRES solution. This trend continues to show when long-term hydrogen storage is an option. However, the increase in costs is significantly reduced, and for all scenarios a solution to achieve weekly energy security can be found. Nevertheless, the total cost roughly increases by 50% in some cases. This increase in cost is a result of weeks with low VRES generation capacity becoming more apparent in the data. To cover these weeks of low VRES generation additional discharging capacity is required, adding significantly to the costs. Additionally, increased charging capacity is required to store abundant reserve energy in a shorter period of time, as the weekly generation profile shows stronger generation peaks. In fact, when a weekly timeframe is concerned, the long-term storage replaces some of the previously assumed short-term storage, which consequently drives up the total cost. Moreover, a switch from onshore wind to solar PV capacity is observed when a weekly timeframe is considered. Solar PV capacity is a less fluctuating power generation method, thus requiring less storage capacity to provide load coverage. Both the weekly and monthly results could be more applicable to the Netherlands, as this is strongly determined by the available short-term storage. If the short-term storage effectively covers the mismatch in generation within a month, the monthly timeframe provides the most accurate solution. However, if short-term storage is more focused on hourly and daily load matching, the weekly timeframe is much more accurate.

Furthermore, the difference between reviewing a multitude of years or years separately should be discussed. Allowing for inter-annual storage results in cheaper solutions, as energy surplus from VRES generation abundant years can be utilized in extreme scenarios, reducing the need for rarely used expensive VRES capacity. Disallowing inter-annual storage forces additional VRES capacity to be installed, reducing storage capacity requirement, nevertheless increasing the total cost. However, the effects on total cost remain limited and the increase in costs maxes at roughly 5%. Considering the single data point entry for the approach allowing inter-annual storage, the results provide an indication on how VRES and storage capacity could be applied, however, no clear conclusions can be drawn.

Lastly, generally speaking, the Pareto Front for all scenarios which allow for long-term storage increase much more linearly as compared to the exponential increase in costs when exclusively VRES is used to provide energy security. Therefore, it is concluded that long-term storage not only allows for much more effective energy security at 90%-load coverage but for a wide variety of energy security levels.

In short, long-term hydrogen storage provides the most cost-effective solution for weekly and monthly energy security and thus promises to play an important factor in our future energy network.

6 The Effects of Future Developments

This chapter provides an overview of what the effect of a number of subjects is to the previously found results. Specifically, battery storage as alternative to long-term storage, offshore wind cost drop, and electrolysis technology developments are reviewed. In this chapter, only Pathway 5 at 90% load coverage and no additional constraints is considered, unless stated otherwise.

Section 6.1 analyzes the cost difference between an inter-annual lithium-ion storage facility and the hydrogen storage facility discussed in this thesis. Section 6.2 discusses the break-even points of offshore wind and electrolyzer costs. Section 6.3 analyzes the effects on total cost, for an increased yearly load profile. Lastly, section 6.4 concludes on the effects of the various cases discussed in this chapter.

6.1 Lithium-Ion Battery Storage: Week versus Month

At the start of this thesis, it is shortly discussed that battery storage is highly unfit for long-term storage. To solidify this claim, a case study is performed using the optimization algorithm developed for the long-term storage scenario and incorporating battery storage technology. Both a weekly and a monthly timeframe are considered. The most famous example of a mass lithium-ion battery storage facility is the Hornsdale Power Reserve, developed by Tesla. This storage facility has a capacity of 193.5 MWh, with a nameplate capacity of 150 MW. The total cost was approximately 161 million Australian dollars, which translates to roughly 98 million Euros. The cost per kWh stored is thus 509€/kWh. It is assumed that there are no extra costs associated with the conversion and reconversion for storage purposes, as the Hornsdale Power Reserve is fully functional with the Australian power grid. Furthermore, no OPEX were included. Conversion and reconversion efficiency were both set at 89%, totaling to roughly 80% round trip efficiency [110].

Performing the optimization results in the findings previously displayed in Figure 4.2 and Table 4.2, meaning that a sole VRES solution is preferred over the usage of long-term lithium-ion storage in achieving monthly energy security. When the usage of lithium-ion battery storage is forced, by for example requiring a storage one-third the size of the hydrogen storage facility, extremely high costs are the result. Such a constraint results in a total cost upwards of 300 billion Euros, making the technology more than twice as costly as the hydrogen storage options, rendering the technology useless for long-term storage in achieving monthly energy security. For weekly energy security, the solution is more cost-effective than exclusively using VRES, as is illustrated in Figure 6.2. However, the result remains twice as expensive as a long-term hydrogen storage solution. Therefore, also for a weekly timeframe, long-term lithium-ion battery storage is no potential candidate.

So when do batteries become a cheaper alternative to hydrogen storage technologies? Figure 6.1 showcases the total system cost when battery technology costs drop significantly for the monthly timeframe. It is only around 20€/kWh that battery technologies finally become cost-competitive with an exclusive VRES solution. Moreover, battery costs have to drop **below** 5€/kWh to become competitive with long-term hydrogen storage, as displayed in Table 6.1.

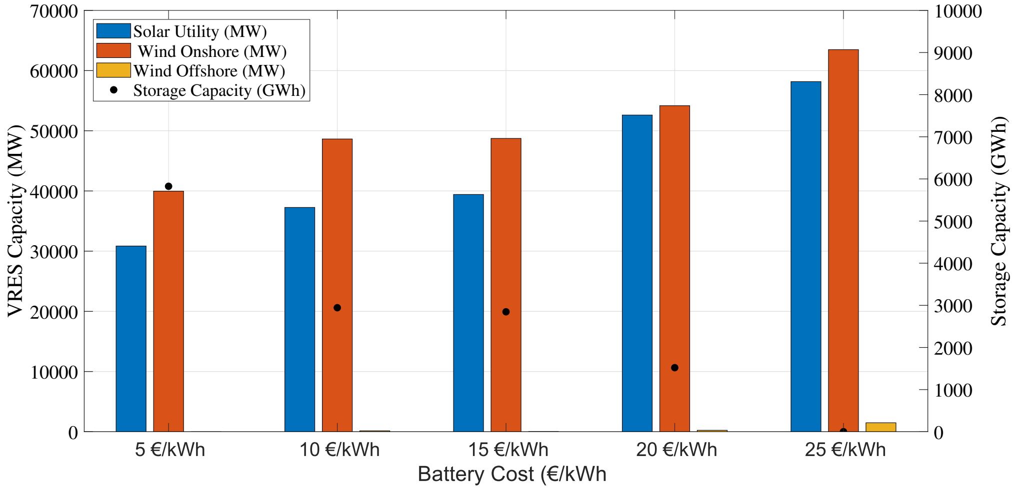


Figure 6.1: Monthly Energy Security: Li-Ion Battery Cost-Range Capacity Overview

The weekly timeframe is slightly more promising for long-term lithium-ion battery storage, as a sole VRES solution is extremely expensive for this timeframe. When lithium-ion battery storage drops to 5€/kWh costs are lower than what can be achieved with hydrogen storage, which costs were 139 and 168 billion Euros for the monthly and weekly timeframe respectively. The total costs for lithium-ion battery storage scenarios are displayed in Table 6.1. Thus a break-even point exists somewhere between 5 and 10€/kWh. Nevertheless, also for a weekly timeframe, at current prices long-term battery storage provides no competition for long-term hydrogen storage.

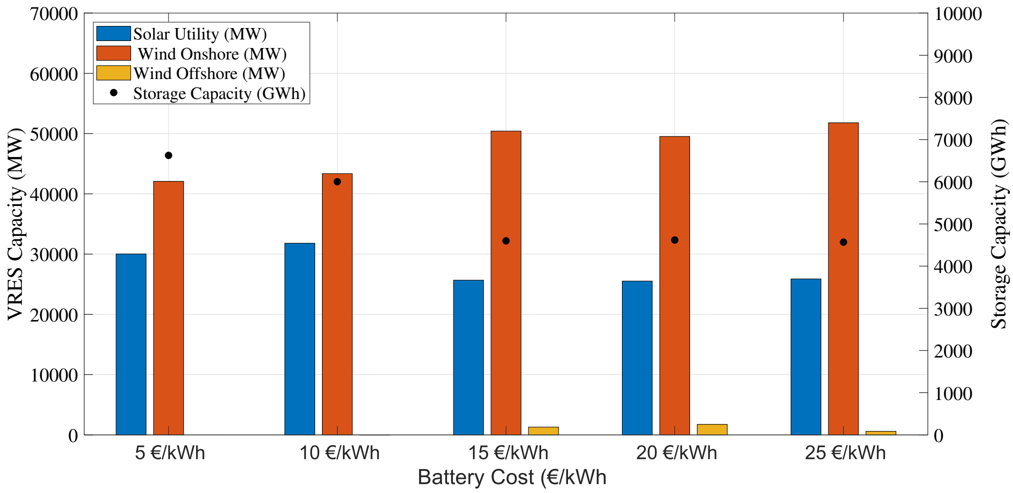


Figure 6.2: Weekly Energy Security: Li-Ion Battery Cost-Range Capacity Overview

In conclusion, prices for lithium-ion battery storage facilities have to drop over 99% before the technology becomes cost-competitive with the hydrogen storage technologies for long-term storage applications. Such a price drop is non-realistic in the near future and thus it can be concluded that lithium-ion battery storage is rightfully not a contender for long-term energy storage. Nevertheless, lithium-ion battery storage and other types of battery storage have a major application in the energy network in the form of short-term load control and local small-scale storage. Short-term storage requires conversion much more often, which makes high-efficiency battery storage more applicable. The result solely emphasizes the need for long-term hydrogen storage, which provides cost-effective weekly and monthly energy security in a VRES dominated power network.

Li-Ion Storage Cost (€/kWh)	Total Cost Month (bln €)	Total Cost Week (bln €)
5	149.85	157.79
10	176.77	189.35
15	191.70	214.15
20	205.83	237.46
25	207.71	259.47

Table 6.1: Total Cost Development Battery Storage

6.2 Cost Break-Even Points: Wind Energy and Electrolyzers

This section discusses the rapid developments occurring in both the fields of electrolyzers as well as wind energy generation. In particular, offshore wind energy has seen rapid development across the globe, including the Netherlands. Therefore, price reductions are expected to occur in the future, making the technique more cost-effective and potentially applicable for achieving energy security. In the field of electrolyzers, AEL is the established technique, while PEMEL shows promising development. A considerate reduction in costs is expected in the future, therefore, it is interesting to review the break-even point between the established AEL and the promising PEMEL.

6.2.1 AEL versus PEMEL

PEMEL is an especially interesting electrolysis technology, as, in contrast to AEL, it has no moving parts, thus greatly reducing OPEX. Therefore, it is expected to become the leading electrolyzer technology in the future. However, as this thesis has shown, at current prices it is non-competitive with AEL. Therefore, it is shortly discussed when a break-even point for this alternative electrolysis method is reached. Furthermore, it is expected that the efficiency of PEMEL will increase in the future, therefore, break-even points for 60 and 70% efficiency have been evaluated as well.

As is illustrated in Figure 6.3 the costs for PEMEL have to drop considerably before the technology becomes competitive with AEL. At the current efficiency for PEMEL (53%) costs have to drop below those currently present for AEL, however, as efficiency increases the break-even point moves to the right and thus higher costs for PEMEL are allowed. Nevertheless, it should be noted that the decrease in electrolyzer cost (or the increase in electrolyzer efficiency) has only a limited effect, a few percent, on the total cost for achieving monthly energy security, as the majority of the costs are represented by the VRES capacity mixture. In short, it must be concluded that PEMEL costs at current efficiency must decrease by roughly 50%. However, depending on the development of the efficiency of PEMEL, a decrease of 25-40% potentially also suffices for cost-competitiveness.

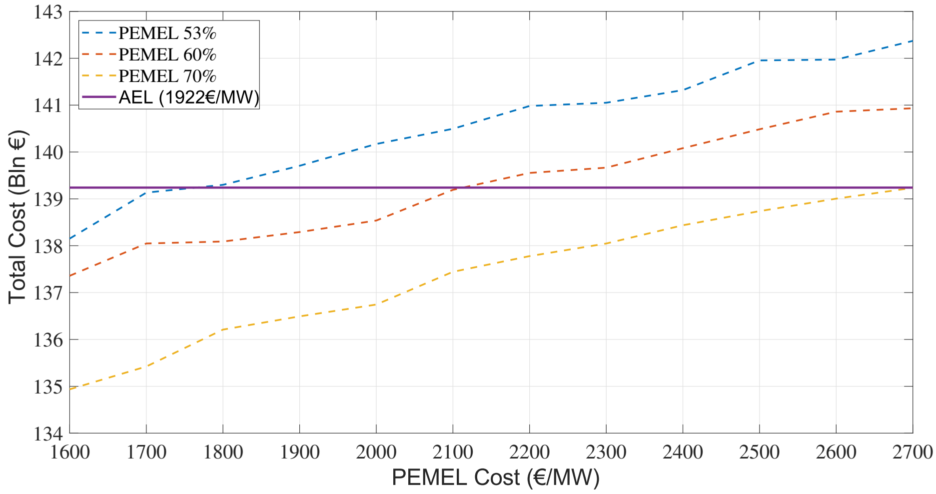


Figure 6.3: Monthly Energy Security: Break-Even Point PEMEL and AEL for Various Efficiencies

Importantly, for the weekly energy security timeframe, the charging capacity plays a more significant role in providing load coverage and thus entails a more significant part of the total cost. However, this has no effect on the break-even points of PEMEL and AEL, they remain at the same cost as before, as is illustrated in Figure 6.4. Nevertheless, as the charging capacity contributes more significantly to the total cost, the total cost does decrease more significantly with decreasing PEMEL cost.

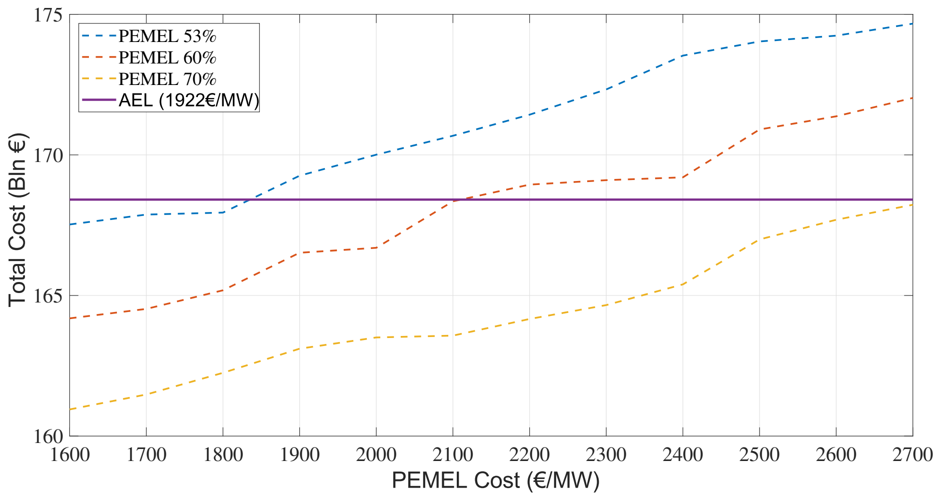


Figure 6.4: Weekly Energy Security: Break-Even Point PEMEL and AEL for Various Efficiencies

6.2.2 Onshore Wind versus Offshore Wind Energy

Recently offshore wind energy has seen strong development in the Netherlands and neighboring countries [63]. However, the results in this thesis show a strong reliance on onshore wind and solar PV power generation, excluding offshore wind power generation as it is too costly. With Dutch goals set for 11 GW offshore wind energy by 2030, the effects of the cost development of offshore wind power generation on the results is, however, most interesting to discuss. Offshore wind farms reach higher capacity factors than their onshore competitors, which are currently much cheaper to develop. However, due to these higher capacity factors, offshore wind farms could become the more cost-effective method for reaching energy security. Therefore, the break-even point between offshore wind energy and the alternative VRES is reviewed in Figure 6.5.

Offshore wind energy remains an undesirable VRES technique for achieving monthly energy security up to a cost of 4000€/MW. However, once the cost drops to 3500€/MW we see a considerate capacity in the total VRES capacity mixture. Reviewing the total cost of this scenario no decrease is found, however, when costs for offshore wind energy drop towards 3000€/MW total costs for achieving monthly energy security decrease by 8 billion euros, from 139 to 131 billion euros, as is illustrated in Table 6.2. Similar results, although with a higher total cost, are the case when a weekly timeframe is considered. A stronger dependence on offshore wind energy and a further decrease in total costs is the natural result of a further decrease in installation costs per MW. Furthermore, as a stronger dependence on offshore wind power generation develops with lower costs, storage capacity increases. The capacity mixture becomes more reliant on a single VRES, which more strongly emphasizes periods of shortage. Therefore, additional storage is required to overcome these periods.

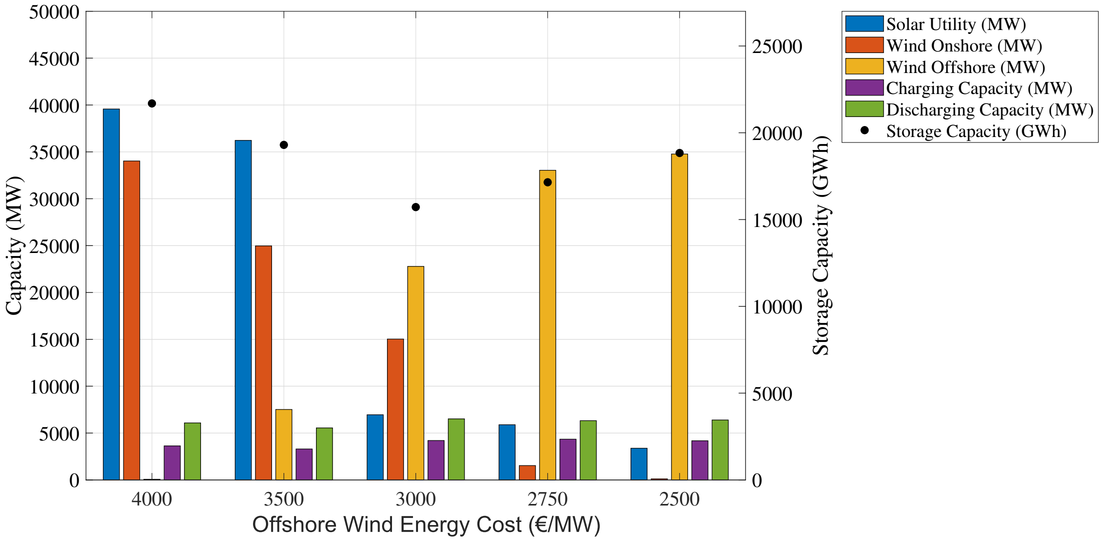


Figure 6.5: Monthly Energy Security: Cost Break-Even Point Offshore Wind Energy

Offshore Wind Cost (€/MW)	Total Cost (bln €)
4627 (Current)	139.17
4000	139.46
3500	139.44
3000	131.27
2750	122.94
2500	113.86

Table 6.2: Total Cost Development Offshore Wind Costs Decrease

Potentially, offshore wind energy can become the sole technique for energy production, if costs drop significantly enough. Nevertheless, for offshore wind energy to make an entry in the VRES capacity mixture, it must initially decrease cost by roughly 25%. However, as offshore wind energy is further developed and costs decrease over the coming years, onshore wind energy will also be further developed thus also decreasing the cost per MW, which is likely to occur more sharply [111]. Therefore, it remains questionable whether in the future offshore wind power generation can make a cost-effective introduction in the VRES capacity mixture.

Still, societal preference can force offshore wind energy to become an important technology, and the projected development in cost will decrease total costs for achieving energy security.

6.3 Load Demand Development

The hourly/daily load profile will most likely change considerably in the future, as local VRES and the further electrification of homes, transport, and industry will have significant effects. However, it remains unsure how the yearly load profile, i.e. the total load consumed, will change alongside these developments. Tennet, the Dutch Transmission System Operator (TSO), keeps a number of future scenarios in mind; the so-called ”International”, ”National” and ”Local” scenarios, which are based on the report ”Net voor de Toekomst” [112].

Here the ”International” scenario considers a yearly load demand of 108.42 TWh, which is highly similar to the current yearly load demand, which has a mean of 111.95 TWh, and that is applied to represent this scenario. The increased energy demand by housing and industry is mostly covered by imported hydrogen, biogas, biomass, and natural gas. Furthermore, half of the passenger transport is electric, and only limited electrolysis and battery storage occur. The ”National” scenario depends much more on local production and consumption of electricity and hydrogen, increasing yearly load demand to 145.6 TWh. All consumed hydrogen is generated domestically and consumed in the passenger transport sector, freight transport, and for low-temperature heating. Furthermore, it is expected that the industry will electrify considerably adding to the total yearly load demand. Lastly, the ”Local” scenario expects an increase in yearly load demand towards 157.95 TWh. Passenger transport will be fully electric, as well as low-temperature heating. Generally, the energy system is less dependent on hydrogen, thus increasing load demand. A summary of the conditions for each scenario is provided in Figure 6.7.

	Local	National	International
Power & Light	25% base-load savings through more efficient appliances. Substantial electrification of industry	25% base-load savings through more efficient appliances. Substantial electrification of industry	25% savings through more efficient appliances
Low-temperature heat	High penetration of heat grids and all-electric (restrictions on green gas, no H_2 distribution) Savings: 23%	High penetration of hybrid heat pumps burning H_2 (and green gas) (restrictions on green gas) Savings: 23%	High penetration of hybrid heat pumps burning H_2 and green gas (mild restrictions on green gas). Savings: 12%
High-temperature & feedstock industry	Circular industry and ambitious process innovation: 60% savings 55% electrification 97% lower CO_2 emissions	Circular industry and ambitious process innovation: 60% savings 55% electrification 97% lower CO_2 emissions	Biomass-based industry: 55% savings 35% biomass 14% electrification 95% lower CO_2 emissions
Passenger transport	100% electric	75% electric 25% hydrogen	50% electric 25% green gas 25% hydrogen
Freight transport	50% green gas 50% hydrogen	50% green gas 50% hydrogen	25% synthetic fuels 25% green gas 50% hydrogen
Renewables generation	84 GW solar 16 GW onshore wind 26 GW offshore wind	34 GW solar 14 GW onshore wind 53 GW offshore wind	16 GW solar 5 GW onshore wind 6 GW offshore wind
Conversion and storage	75 GW electrolysis 60 GW battery storage	60 GW electrolysis 50 GW battery storage	2 GW electrolysis 5 GW battery storage
Hydrogen	100 TWh domestic generation	158 TWh domestic generation	73 TWh import 4 TWh domestic generation
Methane	23 TWh domestic biomethane 35 TWh imported natural gas	46 TWh domestic biomethane 55 TWh imported natural gas	24 TWh domestic biomethane 72 TWh imported natural gas
Biomass			28 TWh import

Figure 6.6: Future Yearly Load Demand Scenarios Characteristics as Expected by Dutch TSO Tennet [112]

For this analysis, it is expected that the increase in load demand occurs evenly for all weeks and months. The new load profile for the various scenarios is calculated by applying the yearly and weekly/monthly standard deviation as determined in sections 3.6 and 3.5 respectively.

These future scenarios are based around a hydrogen economy, which is either domestically generated or imported. The capacities for this domestic hydrogen generation are **not** included in the results, as the results only consider covering the load demand. In the scenarios considered by Tennet, electrolyzer capacity for this hydrogen generation is already considered and exclusively used in periods of energy surplus, thus not adding to the load demand. Storage needs are mostly covered through battery storage, which is replaced by hydrogen storage in this thesis analysis. Interestingly, applying hydrogen storage in achieving energy security, potentially allows for multi-purpose use of its electrolyzers, as both the storage as well as the hydrogen economy can be supplied by these electrolyzers.

Generally, increasing the total yearly load demand significantly adds to the cost, as, in particular, additional VRES capacity is required. As only three scenarios are discussed, two additional yearly load demands were added to check the increase in costs more accurately. No significant difference in increasing cost is present for the weekly and monthly timeframe. Roughly speaking for every GWh additional yearly load demand the total costs increase slightly more than one billion Euros. As the monthly load profile does not change, the ratio of the VRES and storage capacities roughly remains equal. Resulting in a linear increase in total cost for higher yearly load demand. The increase in costs is predominantly due to the additionally required VRES, however, additional storage capacity and discharging capacity also add slightly to the cost.

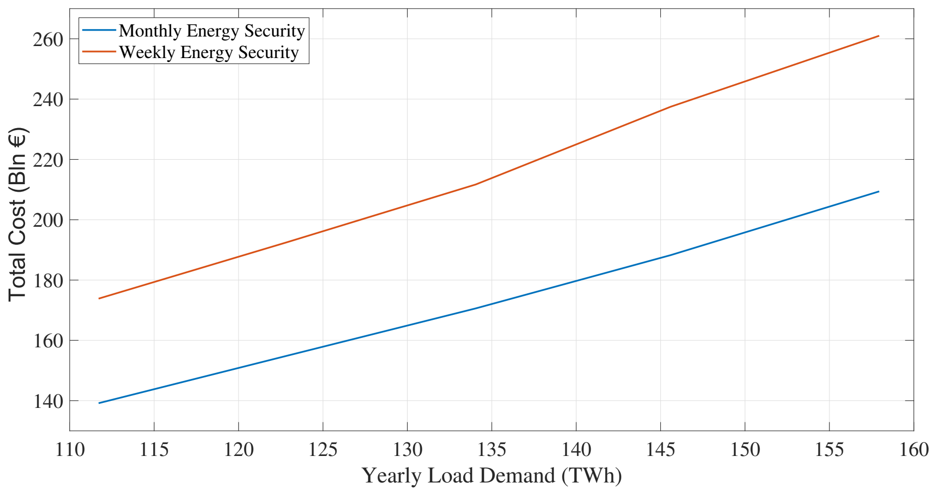


Figure 6.7: Total Cost Development with Increasing Yearly Load Demand

6.4 Conclusions

The developments in the energy network potentially influencing the results are numerous. A number of these have been discussed in this chapter, finding some interesting conclusions for long-term battery storage, as well as break-even points for electrolysis technologies as well as offshore power generation.

First of all, the storage level development is mostly similar when inter-annual storage is or is not allowed. Although total storage capacity differs, discharging events are mostly similar. Furthermore, generally, summer months charge the storage facility, while some extreme winter months with low wind speeds result in significant discharging of the storage facility. Lastly, based on the charging/discharging ratio, it can be concluded that a lifetime of 25 years is easily feasible for the storage facility, potentially having a lifetime upwards of 25 years.

Secondly, long-term lithium-ion battery storage is considerably more expensive than the proposed long-term hydrogen storage solution in this thesis. Both for weekly and monthly timeframe, battery cost has to drop more than 99% to roughly 5€/kWh, before it could become cost-competitive with the hydrogen storage facility.

Thirdly, to review the future potential of alternative electrolysis techniques, the cost break-even point of PEMEL and AEL are reviewed. In the optimal solution, AEL is the dominant electrolysis technique, however, as PEMEL has shown strong technological development recently, it is expected to further drop in cost. The break-even point of PEMEL with AEL lies between 1700-2700€/MW, depending on the development of PEMEL's efficiency, which was evaluated between 53-70%. A cost drop between roughly 25-50% is required before PEMEL becomes cost-competitive with AEL.

Fourthly, the break-even point between offshore wind and alternative VRES power generation was reviewed. Generally, offshore wind energy is costly and is not included in the VRES capacity mixture if not enforced through societal constraints. However, offshore wind power generation can become a cost-effective method for power production if its costs drop roughly 25% to 3500€/MW. A further drop in cost would make offshore wind power generation the primary source of VRES capacity generation, dropping the total cost for achieving weekly and monthly energy security. Although future offshore wind power generation costs are projected to decrease, so are solar PV and onshore wind, thus it remains questionable whether future developments can actually make offshore wind a cost-competitive VRES.

Lastly, a variety of future load profiles were discussed. Three future scenarios, determined by the Dutch TSO (Tennet), were analyzed. Each scenario was incorporated in the optimization by adjusting the total yearly load profile, thus increasing the weekly and monthly load profile equally along the year. A linear increase in costs with increasing yearly load demand is concluded, where 1 GWh increases the total cost slightly over 1 billion Euros for both the weekly and monthly timeframe. The increase in costs is mostly due to the additional VRES capacity required to cover the increased load.

In short, future developments are uncertain and can influence the results in a number of ways. However, if not one single technology makes a tremendous development while its alternatives remain at standstill, the results from Chapter 5 remain an accurate representation for the preferred technologies.

7 Conclusions and Recommendations

Many challenges exist with the implementation of a VRES in the energy system, where most importantly the variability of the sources must be tackled. This thesis provides a framework on how VRES and storage technologies can cooperate to achieve energy security in two separate timeframes (week and month), providing insight into the differences of long-term storage technologies application depending on the available short-term storage. More importantly, this framework is implemented to review a future potential VRES dominated energy system in the Netherlands. The framework consists out of a VRES generation model and separate load model, and identifies the optimal solution using single- and multi-objective genetic algorithms. The VRES generation model is designed for two separately reviewed timeframes, week and month, using 31 years of available weather data (1988-2018), specifically average wind speeds and solar irradiance, for a number of locations in the Netherlands. Using the available weather data, power generation per MW of onshore wind, offshore wind, and solar PV (utility-scale, commercial and residential) are calculated. As the calculations provided lack accuracy, this calculated VRES power generation is compared to limited available real-world VRES power generation data (5-year period) and a correction factor is determined. Applying the correction factor to the 31-year weather data set improves the accuracy of the calculated VRES power generation, and effectively extends the available data on VRES power generation. Additionally, a weekly and monthly 31-year load profile is determined, using available data for load consumption in the Netherlands. Thereafter, both a single and multi-objective algorithm is tasked to provide load coverage for two main scenarios at minimum cost. One exclusively allows the installation of VRES capacity, while the second introduces a variety of storage facilities, which can be utilized to provide load coverage. The single-objective genetic algorithm is applied to provide load coverage in 90% of the 31-year period, thus 28 out of 31 years, helping to exclude extremities. The multi-objective algorithm provides load coverage between 0% and 100% of the 31-year period, effectively including a broad spectrum of weather circumstances in the results. The conclusions discussed in this chapter are based on the single-objective genetic algorithm results, unless stated otherwise. Additionally, a number of sub-scenarios are designed to review the impact of societal preference regarding VRES installations on the total cost in achieving energy security.

Many methods for achieving energy security in the future energy system are possible, however, a big difference in cost-effectiveness is present. First and foremost, it must be concluded that for both a weekly and monthly timeframe, energy security is most cost-effectively achieved by introducing long-term hydrogen storage in the energy system. For the monthly timeframe, as compared to an exclusive VRES system, introducing long-term hydrogen storage decreases total costs (VRES + storage facility capacity costs) for achieving energy security substantially, between 32-36%, as indicated in Figure 7.1. An exclusive VRES solution to provide weekly energy security is extremely costly, 527 billion Euros, and requires excessive space for VRES installations and is, when societal preference is taken into consideration, not achievable. Energy security remains feasible when long-term hydrogen storage is introduced in the energy system and provides energy security at merely a third of those costs, as compared to an exclusive VRES approach. Interestingly, the strict majority of these costs, roughly 75-85% for the weekly and monthly timeframe respectively, are due to VRES capacity investments, indicating that a relatively small investment in storage capacity can do much for achieving energy security.

So which technologies for long-term hydrogen storage are the most cost-effective? Although many technologies for electrolysis and reconversion exist, Alkaline ELectrolysis (AEL) and hydrogen Combined Cycle Gas Turbines (CCGT) provide weekly and monthly energy security at the lowest total cost. AEL is the dominant technology in the electrolysis market, as the maturity of the technique has led to high efficiency and low costs. Similarly, CCGT is a highly mature technique and the relatively easy adaptation towards hydrogen CCGT makes it a low-cost solution. Additionally, the technology has a higher efficiency than any of the currently available fuel cell technologies. Lastly, for the storage capacity technology, a solution mined salt caverns are strongly preferred. Many other techniques are much more costly than this already well-known and widely applied storage capacity technology, while the feasibility of some potentially cheaper methods remains uncertain. Therefore, this robust, reliable, and renowned technique is applied in the proposed framework.

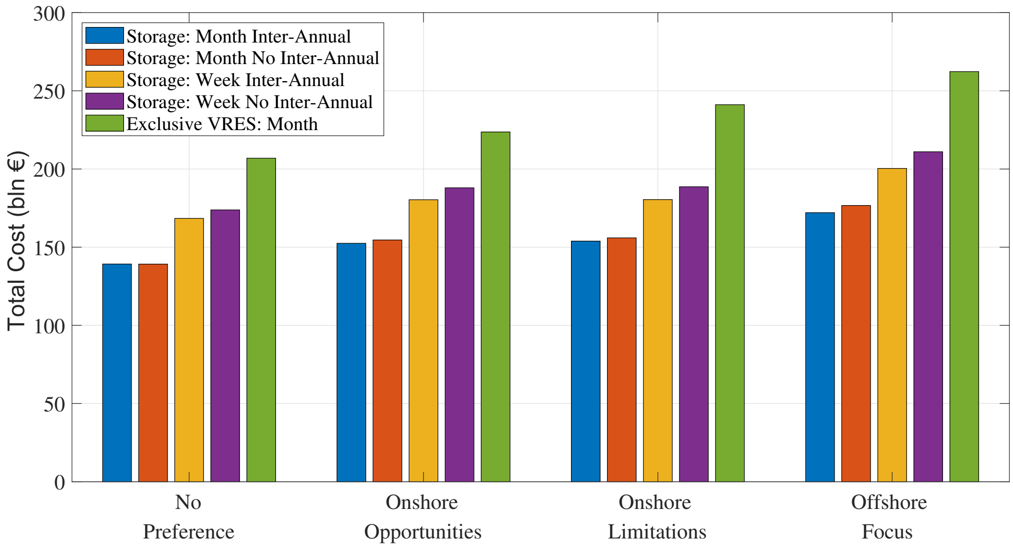


Figure 7.1: Cost Overview of the Various Scenarios for 90% Load Coverage

The multi-objective genetic algorithm provides total cost indications for various percentages of load coverage. Increasing %-load coverage, i.e. including more improbable weather circumstances, drives up the total cost. However, total costs increase more sharply for the exclusive VRES solution than when long-term hydrogen storage is possible. Generally, the Pareto Fronts for all scenarios which allow for long-term storage increase much more linearly with increasing load coverage percentage, as compared to the more exponential increase in costs when exclusively VRES is used to provide energy security. Based on these Pareto Fronts, it is concluded that long-term storage not only allows for much more effective energy security at 90%-load coverage but for a wide variety of energy security levels.

The impact of the restricting societal preference regarding VRES shows congruent results, as more restricting constraints generally increase cost, as is clearly illustrated in Figure 7.1. For the "Onshore Opportunities" and "Onshore Limitations" costs initially increase due to the offshore wind capacity requirement of 11 GW. However, when long-term hydrogen storage is possible, the costs for these scenarios (indicated on the x-axis) remain highly similar, even though additional constraints apply. Due to the potential for long-term hydrogen storage, solar PV can cost-effectively replace the restricted onshore wind capacity. For the exclusive VRES approach, such cost-effective replacement of power generation is not possible, resulting in a constant increase in costs when onshore wind capacity is further restricted. For the "Offshore Focus" scenario for all approaches the costs further increase, as now an onshore wind capacity constraint of 6 GW strictly limits cost-effective onshore wind power generation. Onshore wind capacity remains important to meet load demand in winter months, however, now the capacity has seriously dwindled, additional storage facility capacity is no longer a cost-effective solution. Therefore, to cover the shortage in VRES power generation during the winter months most cost-effectively, offshore wind capacity is required, which drives up the total cost. Thus, societal preference specifically enforcing offshore and opposing onshore wind capacity increases total costs up to 25% for the most strict societal preference scenario.

The two introduced timeframes, weekly and monthly, show considerable differences, where a smaller timeframe increases total costs considerably. However, the timeframe affects the sole VRES approach more considerably than when long-term hydrogen storage is available. For an exclusive VRES approach, the societal preference scenarios become infeasible, while the "No Preference" almost sees a tripling cost for the timeframe adjustment, requiring a surface area larger than some provinces in the Netherlands. However, when long-term hydrogen storage is available, costs develop much less and increase between 20-25% depending on the scenario. The increase in cost is expected, as reviewing a smaller timeframe effectively reduces the short-term storage requirement previously assumed to be present. Effectively, some short-term storage is replaced by long-term storage, as compared to the monthly timeframe, and thus some of its costs are now included. Additionally, the preferred VRES power generation method changes, as for a weekly timeframe solar PV generation becomes the dominating source of power production, as compared to onshore wind power generation for the monthly timeframe. Generally, solar PV power production fluctuates considerably less throughout the month, thus making it a more reliable source for weekly load demand coverage. Onshore wind is much less reliant, as weeks with little wind are a common occurrence. While for the monthly timeframe these weeks were averaged out, now these weeks of power generation shortage become painfully apparent. Furthermore, the storage facility capacity (charging, discharging, and storage) is roughly doubled when a weekly timeframe is considered. This is strongly tied to the system more depending on solar PV capacity for power generation, as energy security in the winter months with low solar PV power generation must still be ensured. Therefore, onshore wind remains present for a weekly timeframe although being partially replaced by additional VRES and storage capacity. Lastly, when utility-scale solar PV is restricted, as in the "Offshore Focus" scenario, commercial solar PV becomes its replacement. However, as limited space is available for commercial solar PV, it can not cover the weekly timeframe completely. Therefore, offshore wind energy is, for the first time, a cost-effective method for achieving weekly energy security. Residential solar PV remains highly costly and is not introduced in any of the scenarios.

Furthermore, the difference between reviewing a multitude of years or years separately should be discussed. To provide results applicable to many future scenarios, the 31-year period was split into 31 years separately reviewed, thus not taking inter-annual storage possibilities into account. Energy security thus must be ensured only using the yearly available power generation. However, the alternative, to consider the period as a whole and allow for inter-annual storage, although having a single data instance, can provide an interesting insight into the effects of inter-annual storage. Allowing for inter-annual storage decreases total costs, as energy surplus from previous years can be utilized in extreme scenarios, reducing the need for rarely used expensive VRES capacity. More importantly, to achieve energy security, the results rely more on the storage facility, as the capacity is roughly doubled. Disregarding inter-annual storage forces additional VRES capacity to be installed, which reduces storage capacity requirement. Nevertheless, total costs increase, as VRES capacity is expensive. However, the effects on total cost remain limited and the increase is maximally roughly 5%. Considering the single data point entry for the approach of allowing inter-annual storage, the results provide an indication of the effects of inter-annual storage, however, no definite conclusion can be drawn.

Lastly, the effects of the future development of technologies are numerous. Most importantly, it is concluded that long-term lithium-ion battery storage is no competition for long-term hydrogen storage, as a drop of roughly 99% in costs, both for a weekly and monthly timeframe, is required before lithium-ion battery storage becomes cost-competitive. However, the development of Polymere Electrolyte Membrane ELectrolysis (PEMEL) is much more promising. A 25-40% decrease in costs is required, depending on the efficiency development of the technology, to acquire a break-even point with the lead technology: AEL. Furthermore, offshore wind potentially also can reach a break-even point and become a cost-competitive method for power generation. For initial adaptation in the VRES capacity mix, offshore wind capacity costs would have to decrease by roughly 25%, however, it should be remarked that, although this cost drop is achievable, also the costs for onshore wind and solar PV are expected to further decrease in the future. Lastly, increasing yearly load demand, which due to the electrification of society could possibly occur, results in linear increasing total costs for achieving energy security.

7.1 Discussion, Recommendations, and Future Work

The accuracy of the results of this thesis is mostly limited by the available data regarding the generation and load profile. Although for the generation profile daily weather data is available, real-world data is limited to monthly national generation values, thus reducing accuracy. More importantly, poor data on the load profile was available, where only data on the monthly national load profile is available. Further research regarding this important input data for the optimization algorithm could lead to more accurate results, although generally it is expected that the current results are a good estimation.

Furthermore, a deeper understanding of the effects of inter-annual storage is essential for the application of long-term storage. However, limited data remains available to review these effects. To make research on inter-annual storage possible, a more extensive set of multiyear data must be generated. To create this data set an artificial weather model generator accurately representing possible weather circumstances, and especially wind speeds and solar irradiance, in the Netherlands should be designed.

Lastly, as currently, no long-term hydrogen storage system is operational, it would be highly advisable to initiate a number of pilot projects, where real-world bottlenecks and complications can be reviewed. Moreover, this can provide a closer insight into the actual costs of such a project. Therefore, it is suggested that the following subjects are further researched

- A generation model based on a more extensive data set, both expanding the available weather data, as well as real-world data input.
- A load profile model based on a more accurate data set. Specifically the need for a weekly load model is highest.
- A weather profile model, helping to further research the effects of inter-annual storage on long-term hydrogen storage capacity requirement
- Initiation of a pilot project regarding long-term hydrogen storage in the Netherlands.

In short, many circumstances can influence the most optimal solution for achieving energy security. However, since the required VRES capacity in all scenarios is a multitude of the currently planned developments for VRES power generation in the Netherlands, one conclusion is apparent: the Dutch government **must** push VRES development to enable the future energy system to be VRES based. Moreover, pilot projects concerning long-term hydrogen storage should be initiated, as this thesis clearly indicates the necessity of long-term storage for acquiring cost-effective energy security in a VRES dominated energy system.

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A Extended Literature Review

In this chapter the present literature on long-term energy storage systems are discussed. The literature was retrieved both through academic sources, as well as by consulting commercial parties. As was discussed in chapter 1.2 many technologies can be applied as energy storage medium, however, not all technologies are serious contenders for large-scale application. Therefore, this chapter also argues which technologies are not be considered for application in this research.

Section 2.1 provides a general overview of the literature landscape with regard to long-term energy storage systems. Section 2.5 elaborates on VRES associated costs, focusing both on capital expenditures as well as operational expenditures. Section **??** presents the costs and efficiency associated to AC/DC conversion methods. Section 2.2 introduces a number of methods for hydrogen production, where the predominant focus is on the various methods for electrolysis. Section **??** briefly discusses the issues correlating to hydrogen transportation. Section 2.3 examines the many methods for hydrogen storage, while also shortly addressing ammonia storage as an alternative to long-term hydrogen storage. Section 2.4 reviews the options to reconvert hydrogen into electricity, addressing fuel cells and hydrogen fired gas turbines. Section **??** analyzes the cost and efficiency for DC/AC conversion methods, ensuring the grid compatibility for the long-term energy storage system. Lastly, section 2.6 concludes on the most applicable storage technologies and creates an overview by drafting six potential pathways for long-term hydrogen storage.

A.1 Variable Renewable Energy Sources

This section discusses the basis for the costs of the VRES more elaborately. Specifically, what is included in the costs per kW is specified more clearly.

A.1.1 Solar Photovoltaics

Solar PV applications can be split into three categories: utility-scale, residential and commercial systems. The costs for these three categories differ significantly, as sizing advantages are substantial.

IRENA provides data on solar PV CAPEX for a range of countries in Europe, however, for the Netherlands no data is presented. Therefore, data on solar PV CAPEX in Germany is utilized, as the economic environments are comparable. Here IRENA presents a cost of $899\$_{2019}$/kW, which includes all hardware and installation costs. Furthermore, soft costs, such as system design and permitting are also included. The OPEX for utility-scale solar PV have not been mapped closely per nation, however, a figure of $10\$_{2019}$/kW is reported as an average in Europe. Therefore, the costs for utility-scale solar PV total at $1149\$_{2019}$/kW, which translates to 988_{2020}/kW.

Residential and commercial solar PV have much higher CAPEX, as the reduced size of the installations increases the overall installments cost per kW. Residential solar PV have the highest costs, as these systems are mostly only up to a few kW, resulting in the highest relative installment costs. Commercial solar PV installations are much more cost comparable to utility-scale solar PV, although still experiencing higher cost per kW. IRENA does not provide residential and commercial CAPEX for the Netherlands, however, for Germany reported costs are 1646 $\$_{2019}$/kW and 1130 $\$_{2019}$/kW respectively. The OPEX are not discussed, therefore, the OPEX from utility-scale solar PV is used as an assumption. Therefore, total costs for residential and commercial solar PV are 1631_{2020}/kW and 1187_{2020}/kW respectively.

A.1.2 Wind Onshore

On onshore wind costs IRENA reports no data for the Netherlands, however, the CAPEX in Europe are determined to be 1800$\$_{2019}$/kW. For the OPEX, values for both Germany and Denmark are given, 56$\$_{2019}$/kW and 33$\$_{2019}$/kW respectively, for which they note that Germany is known for having higher than average OPEX. Therefore, this research adheres to the Danish OPEX as a representative for Dutch OPEX. Translating these values to total investments cost, it is found that onshore wind costs 2258€$_{2020}$/kW.

A.1.3 Wind Offshore

Lastly, offshore wind investment costs are considered. Research done by the PBL ("PlanBureau voor de Leefomgeving") in 2018, mapped the costs for various locations for offshore wind farms in the North Sea accurately [83]. This research concludes that the cost for offshore wind generation is strongly location specific and thus provides cost per location rather than an average. Lensink et al. find that for the most favourable Dutch offshore wind location (Hollandse Kust Zuid (III&IV)) the investment costs, including grid connection, are 3470€$_{2018}$/kW. The associated OPEX for this location were found to be 41$_{2018}$/kW/year. Maximum CAPEX for Dutch offshore wind farms, were found for the location "Boven de Wadden Eilanden", were the Gemini wind farm is located. The investment costs, including grid connection, were calculated to be 4420 €$_{2018}$/kW, where associated OPEX were found to be 64 €$_{2018}$/kW.

In conclusion, the total costs for best and worst offshore locations were thus 4495 €$_{2018}$/kW and 6020 €$_{2018}$/kW respectively, which translate to 4627 €$_{2020}$/kW and 6196 €$_{2020}$/kW. The report written by IRENA does not discuss offshore wind costs for the Netherlands, however, does provide insight into the CAPEX of German offshore wind farms. These were determined to be 4077 $\$_{2019}$/kW, where the associated OPEX were calculated to be 67 $\$_{2018}$/kW. Totalling and translating these costs to 2020 values we find 5035 €$_{2020}$/kW. The costs provided by PBL and IRENA, are thus similar and provide to be useful. This research uses the PBL source as offshore wind cost and utilizes the lower bound, as strong cost reduction has been present in offshore wind projects and are projected for the future.

A.1.4 Summary of VRES Costs

Table 2.9 features all the final costs used in the coming optimization problems.

	Total Cost [€$_{2020}$/kW]
Solar PV (utility-scale)	988
Solar PV (residential)	1631
Solar PV (commercial)	1187
Wind Onshore	2258
Wind Offshore	4627

Table A.1: Overview of the costs of various VRES (based on [83] and [82])

Having covered the generation, the various sub-parts of the energy storage system are discussed.

A.2 Producing Hydrogen

Hydrogen is a widespread used material in oil refinery, steel production, methanol production and ammonia production [50]. Therefore, for the production of hydrogen numerous methods exist, however, not all of them are cost-competitive. Therefore, virtually all hydrogen is produced using a single method, Steam Methane Reforming (SMR). With the call for less greenhouse gas intensive methods of producing hydrogen, recently more research into electrolysis, thermolysis and biomass gasification, has been done. These four methods are now discussed.

A.2.1 Conventional

The conventionally most used method, SMR, requires water (in steam form) and methane, often from natural gas, which together form into carbon monoxide and hydrogen. Consecutively, the carbon monoxide reacts with the water helped by a catalyst to produce additional hydrogen and carbon dioxide (CO_2), which is known as the water-gas shift reaction. Therefore, this production method emits greenhouse gases and has become point of debate in recent years. In total four hydrogen and one carbon dioxide molecules are produced for every methane molecule consumed [113] [51]. It should be noted that there are many other methods for the fabrication of hydrogen through natural gas, however, these are not considered here as SMR is by far the most used technique [114] [51].

Actual prices for hydrogen produced through SMR in the Netherlands are around 1.5€/kg [113]. However, these prices can be expected to increase in the future, as the price for CO_2 increases over the coming years as the CO_2 budget cap is reduced, according to European Commission [115]. The industry aims to find alternative methods of producing hydrogen at this price level. If these price levels can be achieved, a capitalistically driven switch to more sustainable methods of hydrogen production can be expected.

A.2.2 Biomass

One of these more sustainable methods entails hydrogen production using biomass. Various techniques exist to create hydrogen from several biomass sources. The two main categories are biological and thermochemical techniques. Thermochemical methods are preferred as these have lower costs and higher efficiencies. Especially pyrolysis, gasification and super critical water gasification show strong promises for sustainable hydrogen production [116].

Currently the costs for these techniques are considerably higher than for SMR. Biomass pyrolysis comes closest to SMR, with a cost of 3.8$\$_{2016}$ per kg [116]. While biomass gasification costs were calculated to be 3.59€$_{2017}$ per kg [117]. Shahabuddin et al. found that for the various techniques a range of 2.3-5.2$\$_{2020}$ /kg can be found for processing scales around 10 MWth, while for processing scales above 250 MWth a cost range for hydrogen of 2.8-3.4 USD/kg was found [118]. These prices were all based on the capital cost, operating cost and occasionally included taxes. No costs for transport or storage of hydrogen were considered.

Although hydrogen production from biomass might become economically efficient in the near future, some significant complications remain. First of all, hydrogen generation through biomass does not address the strongly increasing intermittency issues in our electrical grid. Furthermore, it remains a question whether there is abundant biomass available to fulfill society's energy consumption need. Ros et al. discuss that realistically speaking only 10% of the energy supply in the EU can be covered through bio-energy, with an optimistic upper bound of 20%. For these two reasons, the pathway of hydrogen generation through biomass is considered in this research.

A.2.3 Thermolysis of Water

A second method to produce hydrogen uses heat, which, at extreme temperatures, can cause the decomposition of water. This method is known as thermolysis. The temperatures required for the process to occur are quite extreme, requiring at least a temperature of 2000 Kelvin. At this temperature some decomposition is initiated, however, the rate of decomposition increases steadily with higher temperatures. As extreme temperatures are required, the process is only deemed fit in situations where ample (waste) heat is available. Examples of utilization of thermolysis would be in combination with solar thermal energy plants.

Thermolysis consists out of various thermo splitting reactions in combination with some chemical reactions for the cycle to be closed. Therefore, the process is known as a thermo-chemical one. Various thermo-chemical processes for hydrogen production are known, however, currently non are commercially available. Considering the limited commercial application in combination with the heat needed, coming from a non-electrical source, thermolysis is not considered a viable way of producing hydrogen for energy storage and is not further discussed in this research [120].

A.3 Hydrogen Storage

Here some of the alternative hydrogen storage methods are discussed more in-depth.

A.3.1 Depleted Gas Fields

Further possibilities for hydrogen storage, which apply specifically to the Netherlands, concern the use of depleted gas fields. Gas fields generally have huge capacities as well as historical proof for the ability to keep a gaseous substance underground [31] [24]. Nevertheless, hydrogen does differ significantly to methane, therefore a careful analysis is needed before a gas field can be issued for use. First of all, the sealing of the reservoir should be considered closely, as hydrogen is a much smaller molecule than methane. Furthermore, the hydrogen might react with the sediment walls of the reservoir as well as the metals in the installation, the latter which is known as hydrogen brittlement. Lastly, there might be residues of various gases in the reservoir, which could react with the hydrogen. All these factors need to be closely considered before a gas field can be considered as a hydrogen storage facility [66].

With regard to the Netherlands van Gessel et al. emphasize that the storage of hydrogen in empty gas field is yet to be proven. Therefore, the preference in initial development of hydrogen storage facilities in the Netherlands is solution mined salt caverns. Additionally, the necessity of the quality of hydrogen is discussed. It is suggested that the mass storage of hydrogen would predominantly be used for heat and seasonal electricity storage, therefore not requiring high purity hydrogen. This was discussed, as gas fields often have residue gases present, which could mix with the stored hydrogen. Taking these conditions into account it was found that onshore effectively a total of 93 billion cubic meters of hydrogen could be stored. Offshore an additional potential for 60 billion cubic meters is present. These values translate in a total storage of 997 PJ (277 billion kWh) and 644 PJ (184 billion kWh), for onshore and offshore respectively. In conclusion, gas field hydrogen storage has a much higher potential in cumulative storage capacity compared to salt caverns. However, this increased potential does come at a lower purity grade, which can limit the use of fuel cell for reconversion to electricity.

The costs for hydrogen storage in depleted gas is a subject that has not been documented extensively, as no depleted gas field has ever been used for hydrogen storage as of yet. Therefore, the subject is mainly a theoretical one with a vast potential and should thus be researched further. An estimation made by Mulder et al. found that hydrogen storage in depleted gas fields could cost as little as 0.075€/kWh, undercutting solution mined salt caverns. These low costs are mainly a result of reduced construction costs (e.g. no excavation costs) and other sizing advantages [113].

Although there is a enormous potential for seasonal hydrogen storage in depleted gas fields, this research does not consider the technology a viable option. Many uncertainties regarding the technological viability remain, thus rendering it unusable in the near future. Further research regarding the storage technology is needed before real-world large-scale applications become a reality.

A.3.2 Metal Hydrides

Apart from storing hydrogen in its basic molecular consistency, one can also have hydrogen stored in alternative molecular forms. One of these examples is as a metal hydride. Metal hydrides store hydrogen in their molecular structure under various circumstances. Usually the metal hydride releases/uptakes the hydrogen depending on temperature, which is in turn closely related to the pressure in the storage container. Methal hydrides have a form changing plateau at a specific pressure where a minor pressure (thus temperature) change can result in a major uptake or release of hydrogen. This makes metal hydrides useful as the amount of hydrogen released or stored can be regulated accurately [121].

Various problems with metal hydrides still exist. First of all, the technique remains limited in its weight percentage hydrogen, therefore not reducing storage containers enough. Although some companies have started working on industrial applications, metal hydrides remain in a developmental phase as of yet. Costs of storage of metal hydrides is currently over 100€/kg, therefore, the use of metal hydrides for large-scale storage remains expensive and non-competitive [122].

A.3.3 Liquid Hydrogen Storage

An alternative to hydrogen storage in gas form is liquid hydrogen storage. The process of liquefaction, transportation and regasification is well explained by Wijayanta et al.. Key elements from their explanation have been taken and used to shortly discuss the topic.

Hydrogen's critical point is reached at extremely low temperatures, therefore, requiring special equipment to both produce and store. Liquid hydrogen storage is roughly three times as dense as compressed hydrogen storage (at 35 MPa) [40]. Therefore, the storage method is very weight effective and thus effective trailer transportation is possible. However, considering the extreme temperatures needed for the transformation of gaseous hydrogen to liquid hydrogen, high electricity costs for cooling are in place. Effectively a third of the supplied hydrogen would be needed to supply enough cooling energy, making the phase transition process very inefficient [123]. The high energy costs are needed for the precooling of the gas, condensation energy of the phase transition and conversion energy required to change the hydrogen from ortho (anti-parallel spin) to para (parallel spin) hydrogen. This change in nuclear spin of the hydrogen electrons is also immediately problematic for the long period storage of liquid hydrogen. The ortho to para change happens naturally as an equilibrium condition is trying to be achieved. The change from ortho to para generates heat, therefore, causing a boiling-off effect. This effect can evaporate between 0.2-0.3% liquid hydrogen per day. To deal with this loss, transport vehicles have been suggested that can utilize the boiled off hydrogen as fuel [40].

Once the hydrogen is needed for consumption, it can be utilized through regasification. Due to the high purity of hydrogen from liquid storage it is very applicable to use in for example fuel cells. During regasifcation the cold heat can be utilized in e.g. district cooling, as to increase the usability of hydrogen. Although it would be beneficial to use this energy for precooling, this is often not possible due to the separate locations for production and consumption.

Taking the various discussed losses into account, hydrogen storage has a 34% efficiency roundtrip [40]. Important to note is that this takes only short storage into account. A longer storage time will result in more losses through the boiling effect, therefore rendering the storage method limited to the short term. Accordingly, this storage method is not an interesting opportunity for seasonal storage and is not further discussed in this research.

A.3.4 High Pressure Hydrogen Storage

An alternative to cooling and liquefaction of hydrogen is high pressure compressed storage. In most of the techniques that have been discussed some compression takes place, however, in high pressure compressed hydrogen storage compression up to 700 bar is common. The energy cost for such compression is roughly 10% of the energy content of the hydrogen gas [70]. The compressed storage is mostly used for automobile applications, as the technique is relatively simple and can store enough fuel to be range comparable to fossil fueled vehicles.

For this hydrogen storage technology the costs are relatively well known for the storage per kWh, as it is widely adopted in hydrogen vehicles. Hua et al. found that the cost per kWh differs between the 350 and 700 bar system, costing 15.4$ and 18.7$ per kWh respectively. However, this research is relatively dated, thus a look at the 2020 targets set up by the U.S. Department of Energy gives light the direction this storage method is taking. These targets quote a storage system cost of 10$/kWh by 2020 and a ultimate decrease to 8$/kWh past 2025 [124]. These costs are considerably higher than the other discussed methods, but the considered systems here are of relatively small size. Therefore, some cost reduction will be achieved through sizing advantages, however, the gap between this technique and the others is to such an extend that it most likely will not become cost competitive. Therefore, the technique is deemed unfit for seasonal hydrogen storage and is not further discussed in this research.

A.3.5 Ammonia Storage

Ammonia can be used as a high density hydrogen storage material and has the advantage that it can be stored as a liquid at relatively high temperatures compared to liquid hydrogen storage. Therefore, ammonia is an easy to handle storage material in contrast to many other forms of hydrogen storage. Furthermore, ammonia is a well established usable end-product in many sectors, therefore a transport and distribution network is in place. This simplifies the use of the product, as no major startup costs for the initial development of a distribution network is needed.

Ammonia synthesis is done through the Haber-Bosch process, which is a reaction between pure nitrogen and hydrogen under a catalyst forming ammonia. This is an exothermic process, therefore some energy is lost through heat production. To reconvert the ammonia into hydrogen the synthesis reaction is inverted. This reaction is endothermic, requiring heat to be performed. If no heat source is available, roughly 15% of the produced hydrogen is needed as a heat supply. The temperature for efficient hydrogen production is between 650 and 1000 degrees Celsius, depending on the catalyst used [38]. Further research is ongoing to use the ammonia directly as a fuel. However, it is debatable how effective such a switch towards a new fuel would be, considering the current pathway most energy using sectors have chosen and the low efficiency of producing electricity this way. Lastly, it is possible to use ammonia directly as a fuel for fuel cells. The ammonia is split over the anode supplying the fuel cell with the necessary hydrogen for operation. This method has a higher electrical efficiency and is therefore often preferred [39]. However, some drawbacks exist with regard to the use of ammonia for some fuel cells. In particular PEM fuel cells do not support direct use of ammonia as a fuel cell, due to the acidic environment in the fuel cell. With regard to AFC and SOFC, no commercially viable applications exist, thus limiting the possibilities in general for the application of direct ammonia usage in fuel cells [39].

To store hydrogen in ammonia form, access to pure nitrogen is necessary. Nitrogen can be retrieved through electrically-driven air separation, which is an additional expense [36]. Palys and Daoutidis have found that a combination between gaseous hydrogen and ammonia storage, depending on the renewable energy scenario, could have a LCOE between 0.17$\$_{2020}$/kWh and 0.28$\$_{2020}$/kWh. However, these values are for more short-term storage in the sense of days/weeks, meaning that costs for seasonal application would be higher. In line with Palys and Daoutidis, Rouwenhorst et al. found that for a small scale (1-10MW) ammonia storage system combined with batteries costs vary between 0.30-0.35€$_{2019}$/kWh for the entire system. For this value relatively short periods of storage are considered, the longer these storage periods become, the more expensive the storage method becomes. Round trip efficiency, thus meaning power to ammonia to power, would be 61%, thus showing much promise for this method. Important to notice is that Rouwenhorst et al. make use conceptual design, which uses a battolyser, instead of a electrolyzer. This apparatus combines a battery with an electrolyser, which produces hydrogen once the battery is charged. These types of systems are currently only available on a small-scale and have yet to be proven for scale-up applications. If instead an electrolyzer would be used to generate the required hydrogen a power-to-ammonia-to-power efficiency of 38% would be possible.

Further research by Wijayanta et al. found 37% efficiency round trip for direct ammonia fueled fuel cells. If instead the ammonia is first reformed into the hydrogen the round trip efficiency would drop to 34% [40]. This research focused on the various transporting methods, and associated costs, of hydrogen from Australia (production location) to Japan (end-use). Predictions for the cost of hydrogen using ammonia transport were made. It was concluded that a cost of 31 JPY/Nm^3 H_2 (2.34€$_{2019}$/kg), resulting in a 17 JPY/kWh (0.14€$_{2020}$/kWh) was to be expected. Further predictions were made that by the year 2050 costs would drop to 26.1 JPY/Nm^3 H_2 and 12 JPY/kWh (0.096€$_{2019}$/kWh). Considering the application of ammonia for transport of hydrogen, this research did not specifically focus on long term storage. Nevertheless, it does provide interesting insight in the future costs of electricity production through hydrogen stored in a chemical bond.

Energy storage through ammonia seems to have a promising future, however, be it more focused on daily and weekly storage cycles. The costs for ammonia storage remain as of yet more expensive than alternatives such as solution mined salt caverns as well as the use of depleted gas fields, especially when considered for seasonal application. Therefore, this research does not apply ammonia storage as a viable cost-effective technology for seasonal energy storage.

B Further Results for the Alternative Pathways in Achieving Energy Security Using VRES and Long-Term Hydrogen Storage

In this Appendix chapter more generated results for the alternative pathways are provided. The results are simply stated with no further explanation, as the most relevant results have been discussed at length in the main body.

B.1 Achieving Monthly Energy Security No Inter-Annual Storage

Figure B.1 portrays the Pareto fronts for all pathways and societal scenarios for achieving monthly energy security together.

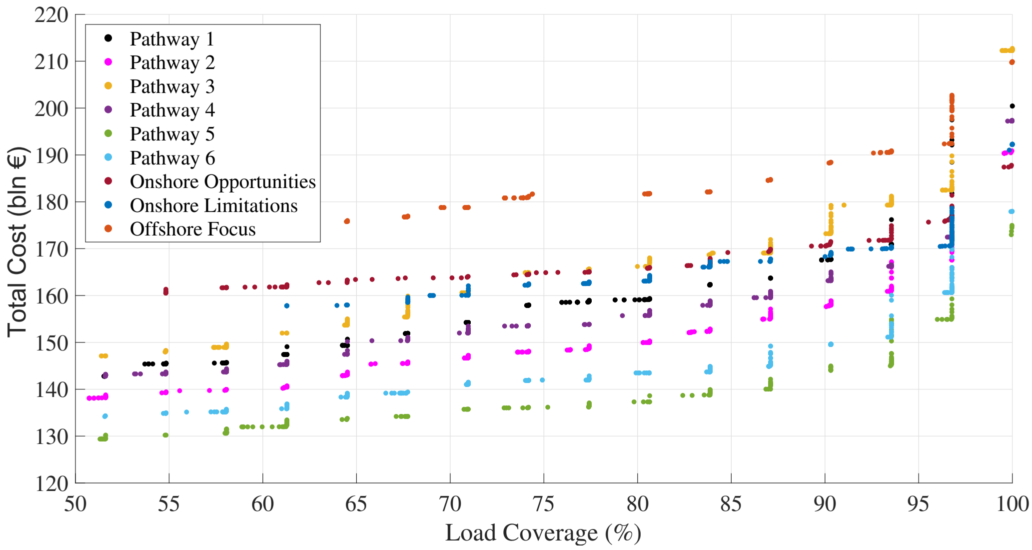

Figure B.1: Monthly Energy Security No Inter-Annual Storage: Societal Scenarios and Pathways Total Cost Pareto Fronts

B.1.1 90 % Load Coverage

Figure B.2 displays the resulting capacities per pathway when 90% load coverage is considered.

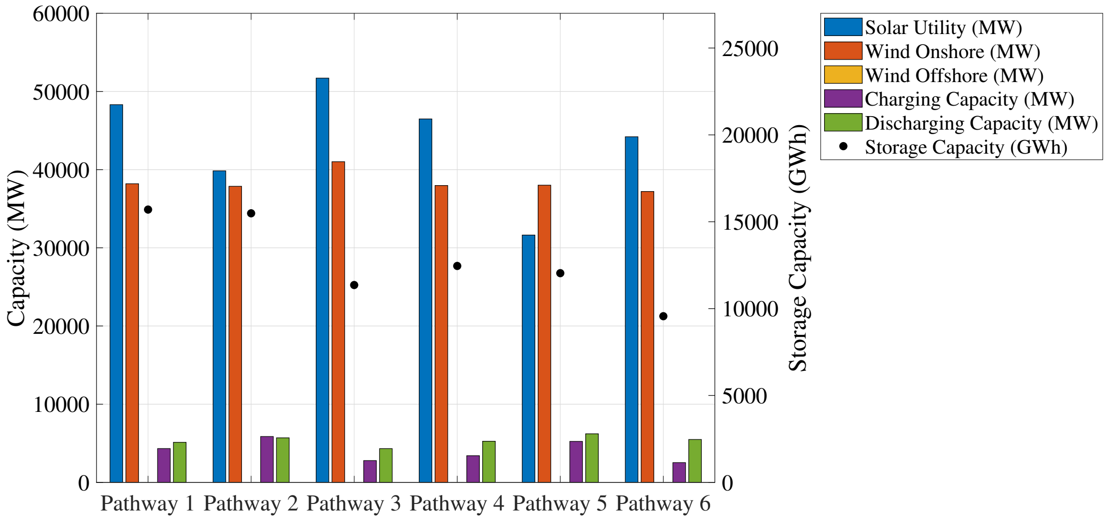

Figure B.2: Monthly Energy Security No Inter-Annual Storage: Pathway Capacity Results 90% Load Coverage

The numeric overview of Figure B.2 is given in Table B.1, where the total cost per pathway has been included.

	Cost (bln €$_{2020}$)	Storage Capacity (GWh)	Solar PV (MW)	Wind Onshore (MW)	Charging Capacity (MW)	Discharging Capacity (MW)
1	164.66	15702	48310	38195	4324	5120
2	155.04	15487	39847	37869	5864	5695
3	171.74	11358	51705	41016	2785	4317
4	160.56	12456	46486	37970	3412	5259
5	139.17	12041	31634	38012	5239	6210
6	146.91	9564	44206	37206	2526	5484

Table B.1: Monthly Energy Security No Inter-Annual Storage: Pathway Cost and Capacity Overview 90% Load Coverage

B.2 Achieving Weekly Energy Security No Inter-Annual Storage

Figure B.3 portrays the Pareto fronts for all pathways and societal scenarios for achieving monthly energy security without inter-annual storage together.

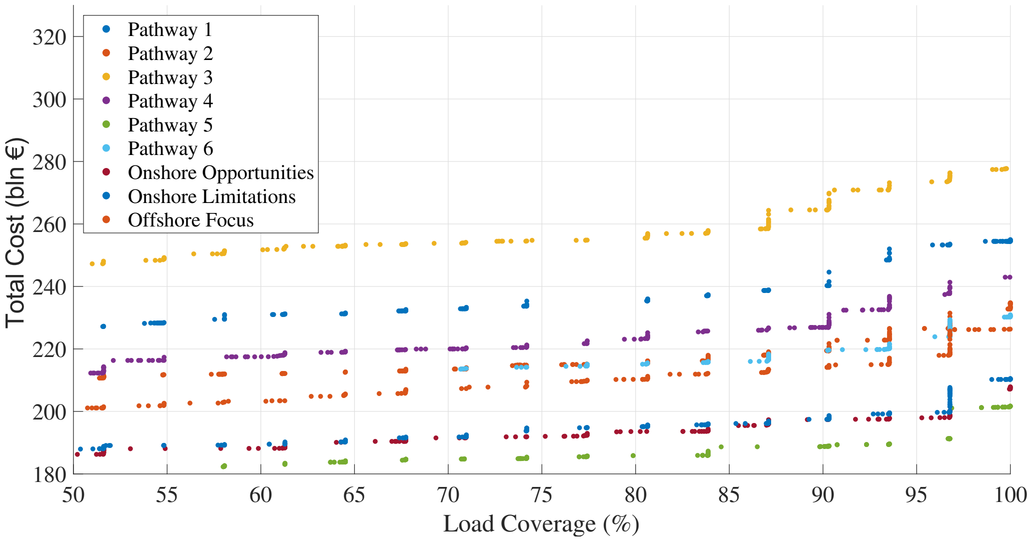

Figure B.3: Weekly Energy Security No Inter-Annual Storage: Societal Scenarios and Pathways Total Cost Pareto Fronts

B.2.1 90 % Load Coverage

Figure B.4 displays the resulting capacities per pathway.

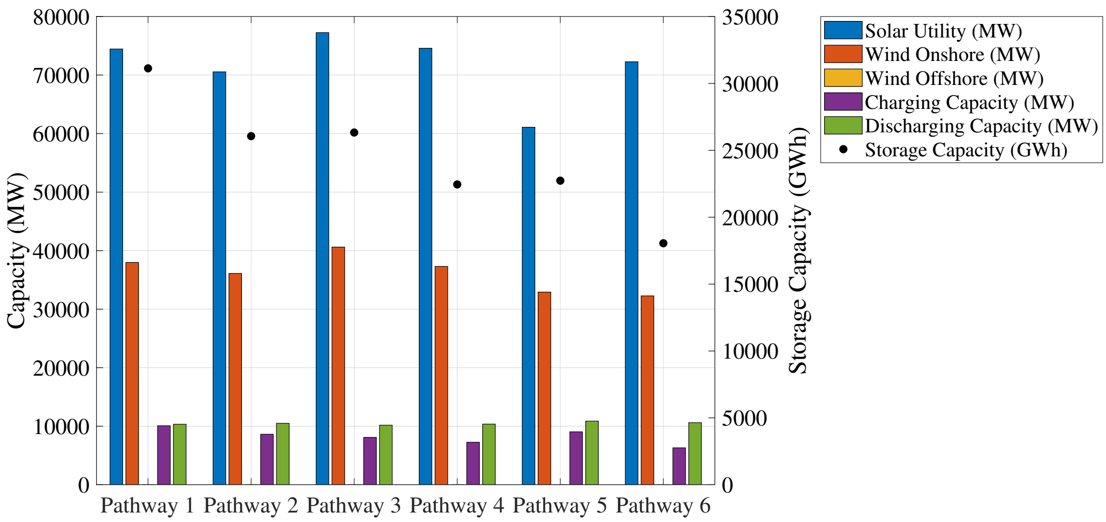

Figure B.4: Weekly Energy Security No Inter-Annual Storage: Pathway Capacity Results 90% Load Coverage

Table B.2 displays an overview of the costs and capacities of the various pathways.

	Cost (bln €$_{2020}$)	Storage Capacity (GWh)	Solar PV (MW)	Wind Onshore (MW)	Charging Capacity (MW)	Discharging Capacity (MW)
1	223.62	31128	74450	37982	10085	10337
2	201.51	26060	70548	36106	8628	10496
3	239.42	26329	77258	40611	8094	10174
4	215.82	22447	74585	37297	7262	10361
5	173.84	22731	61086	32913	9044	10869
6	186.37	18052	72270	32268	6310	10610

Table B.2: Weekly Energy Security No Inter-Annual Storage: Pathway Cost and Capacity Overview 90% Load Coverage

B.3 Achieving Monthly Energy Security with Inter-Annual Storage

Figure B.5 displays the Pareto Fronts for all pathways.

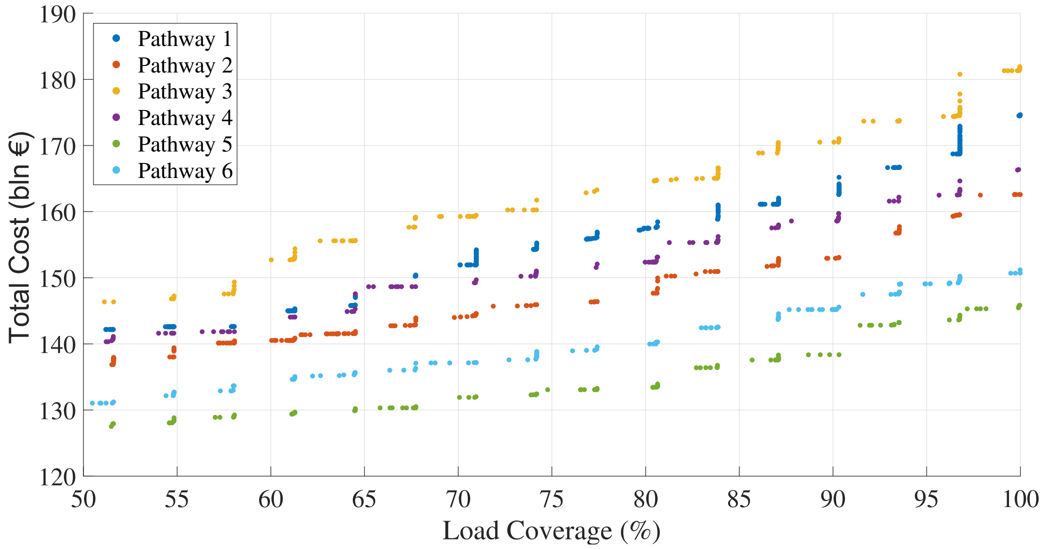

Figure B.5: Monthly Energy Security Inter-Annual Storage: Pathway Total Cost Pareto Fronts

B.3.1 90% Load Coverage

Figure B.6 displays the results for the VRES and storage capacity for the six individual pathways.

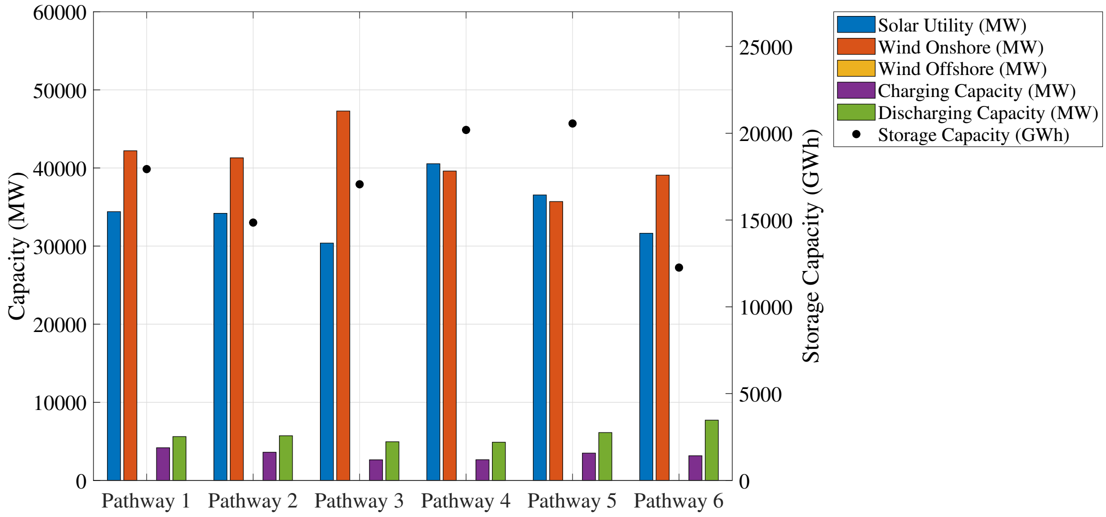

Figure B.6: Monthly Energy Security Inter-Annual Storage: Pathway Capacity Results 90% Load Coverage

Table B.3 provides the cost and capacity overview of all pathways.

	Cost (bln €$_{2020}$)	Storage Capacity (GWh)	Solar PV (MW)	Wind Onshore (MW)	Charging Capacity (MW)	Discharging Capacity (MW)
1	162.17	20911	34406	42204	4181	5609
2	152.62	20158	34192	41299	3607	5717
3	168.78	25125	30382	47290	2637	4949
4	158.38	19507	40542	39607	2648	4888
5	139.24	21554	36542	35701	3493	6125
6	144.57	18496	31640	39081	3157	7714

Table B.3: Cost and Capacity Overview of the Various Pathways

B.4 Achieving Weekly Energy Security with Inter-Annual Storage

Figure B.7 provides the Pareto front for the weekly timeframe for all pathways.

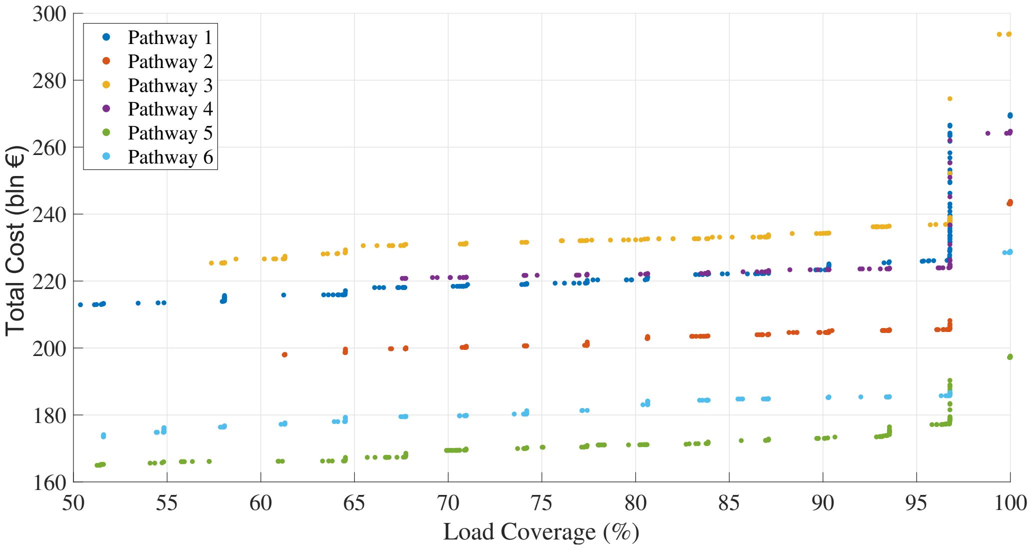

Figure B.7: Weekly Energy Security Inter-Annual Storage: Pathway Total Cost Pareto Fronts

B.4.1 90% Load Coverage

Figure B.8 shows the effect of the adjusted timeframe on the resulting VRES and Storage Capacities.

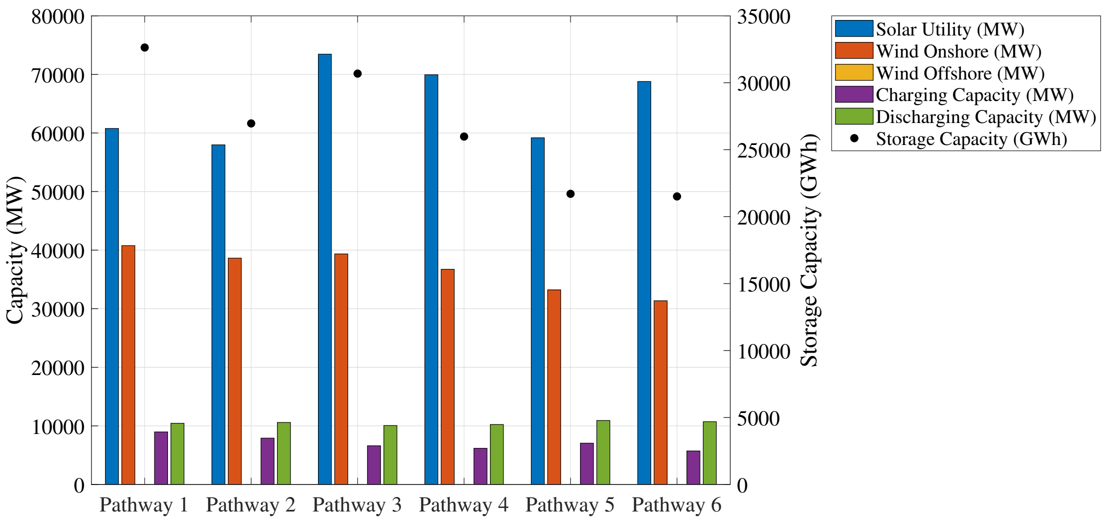

Figure B.8: Weekly Energy Security Inter-Annual Storage: Pathway Capacity Results 90%-Load Coverage

Table B.4 provides the numeric overview of Figure B.8.

	Cost (bln €$_{2020}$)	Storage Capacity (GWh)	Solar PV (MW)	Wind Onshore (MW)	Charging Capacity (MW)	Discharging Capacity (MW)
1	215.25	32633	60766	40774	8965	10443
2	194.00	26962	57972	38632	7909	10583
3	229.09	30684	73452	39346	6607	10060
4	207.39	25981	69940	36732	6175	10236
5	168.41	21706	59179	33224	7047	10919
6	180.42	21511	68787	31360	5717	10715

Table B.4: Weekly Energy Security Inter-Annual Storage: Pathway Cost and Capacity Overview 90% Load Coverage

C Conference Paper

Achieving Weekly and Monthly Energy Security Using Renewable Energy Sources and Long-Term Hydrogen Storage

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***Abstract*—This paper discusses how weekly and monthly energy security can be achieved in the Netherlands exclusively using long-term hydrogen storage and Variable Renewable Energy Sources (VRES). Based on historical weather data a weekly and monthly capacity variable generation profile over the period 1988-2018 for the VRES onshore wind, offshore wind and solar PV is modeled. The generation profile is then matched by adjusting VRES and long-term storage capacity with a weekly/monthly load profile over the same period, which is adjusted to reflect current load demand. An optimization problem is set up, where VRES power generation and the opportunity for long-term hydrogen storage is reflected and an optimal result, i.e. the least cost solution, to achieve weekly/monthly energy security is obtained using a genetic algorithm. Additionally, a variety of societal preferences regarding the VRES capacity mixture are represented in the optimization problem through constraints. By assessing individual years in the period 1988-2018 entailing varying weather circumstances, it can be concluded that long-term hydrogen storage in combination with VRES allows to achieve weekly and monthly energy security in the future for 139 and 178 billion Euros respectively. Stricter constraints generally increase total costs, however, in some cases utility-scale solar PV can cost-effectively replace the initially preferred but now restricted onshore wind capacity. The total costs increase up to 155-211 billion euros depending on the timeframe and societal constraints. Reviewing a smaller timeframe, weekly instead of monthly, costs to achieve energy security increase, and the preferred VRES power generation method moves from onshore wind to utility-scale solar PV.**

***Index Terms*—Renewable Energy Sources, Netherlands, Long-Term Storage, Hydrogen, Optimization Problem**

I. Introduction

Variable Renewable Energy Sources (VRES) are quickly replacing conventional power generation methods and will dominate electrical grids worldwide in the near future[1]. However, VRES exhibits a discontinuous energy output highly unfit for our current energy system, which requires a nearly perfect balancing of supply and demand at all times. Therefore, as VRES quickly replaces conventional power generation, the security of supply, i.e. energy security, of the system is endangered.

Various solutions to ensure energy security are suggested, such as power rerouting, retaining back-up conventional storage, expanding installed VRES capacity, and most importantly long-term storage. Limited research regarding energy system-wide implementation of storage systems is done. Nevertheless, many storage technologies are available, of which particularly hydrogen storage technologies have shown great promise, due to low cost for these large-scale applications. This research aims to provide a framework on how weekly/monthly energy security can be potentially cost-effectively achieved using long-term hydrogen storage exclusively in combination with VRES. Using this framework an optimal mixture of VRES and long-term hydrogen storage capacity is determined to provide energy security in the Netherlands for two timeframes: week and month.

The structure of the paper is as follows. Section II discusses the costs of the VRES and long-term storage affiliated technologies. Section III explains the applied methodology in-depth, focusing in particular on the used capacity sizing variable VRES power generation model. Section IV introduces the variety of results, discussing both timeframe and societal preference effects. Finally, Section V concludes and summarizes the findings of this research.

II. VRES and Hydrogen Storage Technologies

Hydrogen storage facilities consist of three main processes: conversion to hydrogen, storage of hydrogen, and reconversion to electricity.

First, the conversion of electricity to hydrogen is achieved using electrolysis. Many methods for electrolysis exist, however, this paper opts to use Alkaline ELectrolysis (AEL), as this is currently the technology with the lowest cost and highest efficiency and appears to be easily applicable in a long-term hydrogen storage facility.

For hydrogen storage also many options exist, which come at a wide range of costs and applications. Today, solution-mined salt caverns are a low-cost, high-volume well-developed long-term hydrogen storage technology. Therefore, solution-mined salt caverns are the method for

TABLE I
TECHNOLOGY COST OVERVIEW

	Total Cost (€$_{2020}$/kW)	Efficiency (LHV, η)	Sources
Solar PV (utility-scale)	988	n.a.	[2]
Solar PV (residential)	1631	n.a.	[2]
Solar PV (commercial)	1187	n.a.	[2]
Wind Onshore	2258	n.a.	[2]
Wind Offshore	4627	n.a.	[2, 3]
AEL	1922	55.5	[4, 5, 6] [7, 8, 9, 10]
Hydrogen CCGT	1053	60	[11, 12]
Salt Cavern (per kWh)	0.455	n.a.	[13]

hydrogen storage in this paper.

Lastly, reconversion of hydrogen to electricity in periods of shortage is required. Fuel cells are a strongly developing technology, however, remain as of yet highly costly as compared to hydrogen-fueled Combined Cycle Gas Turbines (CCGT). CCGT is a well-developed and known technique, which results in low cost and high efficiency, easily out-competing any fuel cell technology for large-scale applications.

Table I provides a brief overview of the technologies and the associated costs per kW are given, providing an overview of the used cost for the final total cost calculations. Additionally the costs associated with VRES are portrayed in this table. Three VRES are considered for energy generation in the Netherlands: onshore wind, offshore wind, and solar PV. Solar PV power generation has three areas of application; utility-scale, commercial and residential, which have three different cost levels.

In Table I CAPital EXpenditures (CAPEX) and OPerational EXpenditures (OPEX) are combined in one total cost per technology. The combination of CAPEX and OPEX is based on a 25-year technological lifetime for all technologies. Furthermore, discounting is disregarded.

III. METHODOLOGY

To achieve energy security exclusively using VRES and long-term hydrogen storage, the system must be robust and capable of handling many weather circumstances. Power generation through VRES is volatile and differs from on a week-to-week and month-to-month basis, as is shown for onshore wind power generation in the monthly timeframe in Figure 1. Across years power generation also varies, resulting in a volatile and non-predictable generation profile, which makes it hard to couple VRES to our current energy system.

To review the effect of weather circumstances on VRES power generation in the Netherlands, real-world data reaching back to 2014 can be used. However, this is a relatively short period of time entailing only a limited amount of weather circumstances, thus an extension of this data set is required. Therefore, weather data, which is available back to 1988, is used to effectively extend the available VRES power generation data. For the period 1988-2018 onshore and offshore

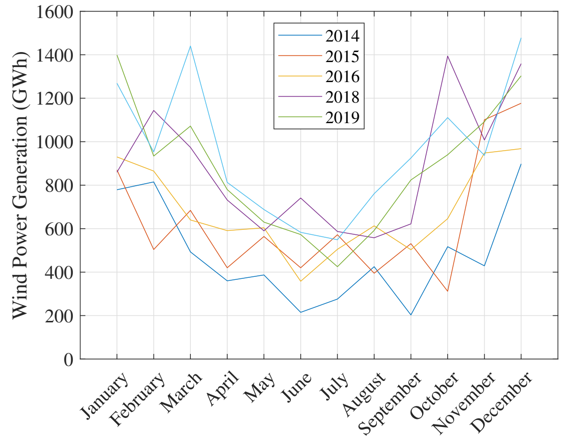

Fig. 1. Monthly Wind Power Generation in the Netherlands (2014-2019)

wind power generation is calculated using height-adjusted wind speeds input in the wind power law, while solar PV power generation is determined using available solar irradiance measurements and an estimated average solar panel efficiency for the Netherlands. Nine locations provided weather data, helping to find representative national average VRES power generation. The calculated VRES power generation is corrected using available real-world VRES power generation data for the period 2015-2018, helping to increase the accuracy of the model. Generally, the model slightly overestimates power generation, as many real-world complications, e.g. maintenance downtime, are not considered. However, these limitations are now incorporated because of the correction factor. The calculated, based on weather station data, and real monthly offshore wind power generation are portrayed for 2017 and 2018 in Figure 2, which also showcases this overestimation.

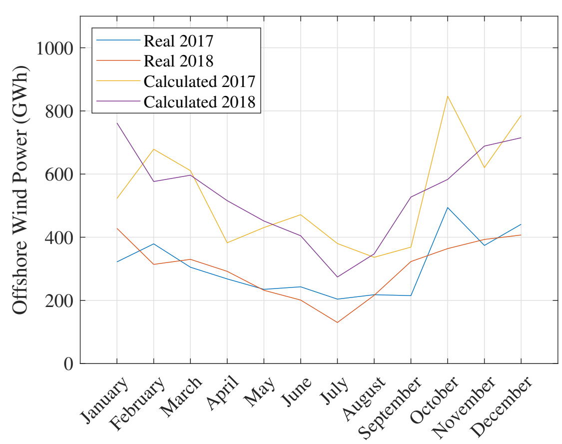

Fig. 2. Real and Calculated Monthly Offshore Wind Power Generation (2017/2018)

Furthermore, load demand is considered. Load demand has been steadily rising over the past decades, and thus requires adjustment to reflect current load demand throughout the 1988-2018 period. Based on the weekly/monthly standard deviation in the period 2008-2018 a new weekly/monthly load profile for the period 1988-2018 is constructed using a normal distribution. Figure 3 shows the yearly total load demand for the constructed and the real data.

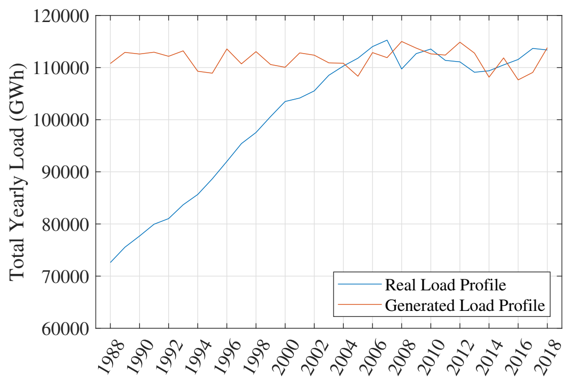

Fig. 3. Real and Calculated Yearly Load Demand (1988-2018)

In short, these calculations and corrections, model a weekly and monthly capacity-dependent VRES power generation profile for onshore wind, offshore wind, and solar PV over the period 1988-2018, and construct a realistic load profile based on the current load demand for the same timeframes and period.

A. Genetic Algorithm

Having acquired a generation and load profile reflecting the variability of the power generation and load demand over a long period of time, the most cost-effective solution in providing energy security, i.e. matching the generation and load profile, is found by setting up an optimization problem which is solved using a genetic algorithm. The genetic algorithm is enforced to provide weekly/monthly load coverage in 90% of the considered years in the period 1988-2018 the load is covered every month, which helps to exclude extremes. This 90% load coverage is determined, as the final 10% of the years are more cost-effectively covered through alternative methods than long-term hydrogen storage and VRES, as was determined by setting up a Pareto Front for the optimization problem, which varied load coverage between 50-100%. This Pareto Front showed a considerable increase in costs for the final 10% load coverage. The objective of the genetic algorithm is to provide energy security at minimal cost. It is important to note that short-term storage, intra-week, and intra-month, is assumed to be abundantly present for the weekly and monthly timeframe respectively. In other words, for the weekly timeframe, day-to-day variations are resolved through short-term storage, such as batteries. For the monthly timeframe, this means also week-to-week variations are resolved using this freely available short-term storage.

B. Drafting Scenarios

To represent societal preferences a multitude of scenarios, enforced by constraints in the optimization problem, are discussed, helping to find more society reflective results. VRES installation development is heavily influenced by the general public and some VRES have seen considerable protests in the Netherlands, especially onshore wind and utility-scale solar PV. Furthermore, the Dutch government has planned a considerable expansion of offshore wind energy capacity, which should be represented in these scenarios. Therefore, four scenarios; ”No Preference”, ”Onshore Opportunities”, ”Onshore Limitations”, and ”Offshore Focus”, discussed for both timeframes, are drafted and consist out of varying levels of limitation with regard to these VRES capacities. Table II provides a general overview of the constraints applied in the various scenarios.

TABLE II
OVERVIEW OF CONSTRAINTS REPRESENTING SOCIETAL PREFERENCE SCENARIOS

	Onshore Opportunities	Onshore Limitations	Offshore Focus
Solar PV (utility-scale)	$\leq$ 150 GW	$\leq$ 150 GW	0
Solar PV (residential)	$\leq$ 93.8 GW	$\leq$ 93.8 GW	$\leq$ 93.8 GW
Solar PV (commercial)	$\leq$ 54.9 GW	$\leq$ 54.9 GW	$\leq$ 54.9 GW
Wind Onshore	$\leq$ 50 GW	$\leq$ 17 GW	$\leq$ 6 GW
Wind Offshore	11-60 GW	11-60 GW	11-60 GW

Figure 4 summarizes the three steps discussed in this chapter to acquire the results.

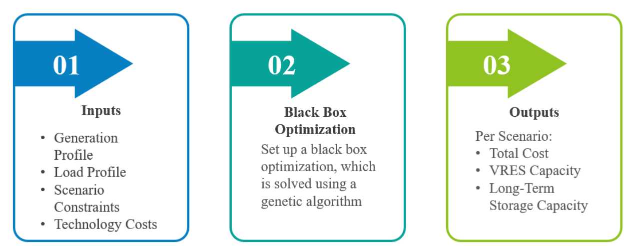

Fig. 4. Stepwise Summary of the Methodology

IV. RESULTS

Figure 5 entails total costs per societal preference scenario and timeframe. First of all, it should be noted that for the weekly timeframe an exclusive VRES solution (not using any long-term hydrogen storage) can only be obtained in the No Preference scenario and that its costs are a multitude of when energy security is achieved when also long-term hydrogen storage is utilized. All other scenarios do not allow the immense VRES capacity required to provide energy security exclusively using VRES. Energy security is much more cost-effectively achieved, for all scenarios and timeframes, when long-term hydrogen storage is available. To put the results into perspective, total costs are roughly around 75% of the yearly Dutch governmental budget. Moreover, it is important to note that only 15-25% (monthly/weekly) of the total costs are due to the long-term hydrogen storage facility, most investment remains to be done with regard to VRES capacity. The weekly timeframe experiences higher costs in achieving energy security across all scenarios than the monthly timeframe. This is a logical result, as previously "free" short-term storage (intra-month) is now no longer assumed and is incorporated in the total costs. Lastly, generally costs increase when more VRES capacity restrictions are applied. An exception is the further constraints applied between the Onshore Opportunity and Onshore Limitations scenario when long-term hydrogen storage is available. The costs increase stagnates and only increases when the very strict Offshore Focus scenario is enforced. However, the total costs increase across the scenarios is only slight when long-term storage is available, only increasing costs by roughly 25%.

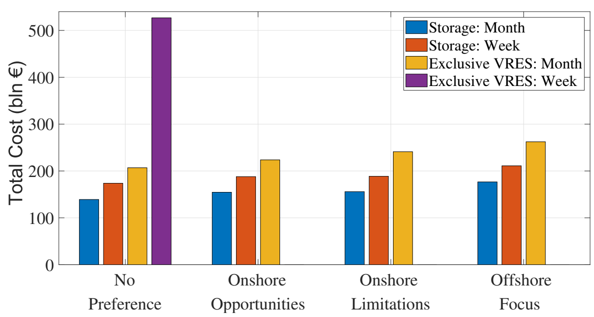

Fig. 5. Total Cost Overview per Societal Preference Scenario and Timeframes

A. Timeframe Effects

Moving from a monthly to a weekly timeframe increases costs and Figure 6 explains where this increase in total costs comes from for the No Preference and Onshore Opportunities scenario. Only two scenarios are shown, as the timeframe adjustment effects are similar among all of them. The preferred VRES power generation method changes, as for a weekly timeframe solar PV generation becomes the dominating source of power production, as compared to onshore wind power generation for the monthly timeframe. Generally, solar PV power production fluctuates considerably less throughout the month and is thus during the summer a more reliable VRES for weekly load demand coverage. Onshore wind is much less reliant, as weeks with little to no wind are a common occurrence throughout the year. While for the monthly timeframe these weeks were averaged out, now these weeks of power generation shortage become painfully apparent. Additionally, the storage facility capacity (charging, discharging, and storage) is roughly doubled when a weekly timeframe is considered. This is strongly tied to the system more depending on solar PV capacity for power generation, as energy security in the winter months with low solar PV power generation must still be ensured. Therefore, onshore wind remains present for a weekly timeframe although being partially replaced by additional utility-scale solar PV and storage capacity. Furthermore, in the smaller timeframe, weeks with little to no wind and solar power generation exist, which require additional discharging capacity to ensure energy security. In line with this, additional charging capacity is necessary as the storage facility is required to charge more quickly to cover such events which follow each other shortly.

B. Societal Preference Effects

More restricting constraints regarding the implementation of the VRES generally leads to increasing costs. Figure 7 provides a more detailed insight into the results per scenario for the monthly timeframe. Implementing the first scenario "Onshore Opportunities" the increase in costs is predominantly due to the offshore 11 GW constraint. Offshore wind is considerably more costly than onshore alternatives, driving up the costs considerably. Interestingly, the total costs do not increase significantly when further onshore wind constraints are introduced in the "Onshore Limitations" scenario. The availability of the long-term storage facility allows onshore wind to be cost-effectively replaced by utility-scale solar PV, while still ensuring energy security. Surplus power generation during the summer months helps to cover the more shortage-prone winter months. However, when this utility-scale solar PV is completely restricted in the "Offshore Focus" scenario we see this predominantly being replaced by commercial solar PV. Furthermore, further restrictions for onshore wind are covered by an expansion of offshore wind power generation. This is remarkably the first time that offshore wind power generation is a cost-effective method and is introduced freely. Lastly, charging and discharging capacity decreases when societal preference moves the VRES capacity mixture towards less fluctuating sources of power generation (solar PV and offshore wind), as the extreme scenarios have decreased in severity. However, the storage capacity results do not show congruent results.

Figure 8 illustrates the results for the societal preference scenarios in the weekly timeframe more elaborately. The capacities develop slightly differently, as utility-scale solar PV already plays a significant role in the No Preference scenario, due to the shorter timeframe. Therefore, onshore wind capacity constraints are not binding in both the Onshore Opportunities and Onshore Limitations scenario. The constraint for 11 GW offshore wind is thus the only binding constraint in these scenarios and causes the initial increase in cost. Moving towards further restrictions regarding utility-scale solar PV in the Offshore Focus scenario, we see a considerable move towards commercial solar PV, utilizing all available capacity. However, residential solar PV is not introduced, as it remains too costly. Instead, offshore wind remains the important second method of VRES power generation for this scenario. Charging, discharging, and storage capacity do not change significantly,

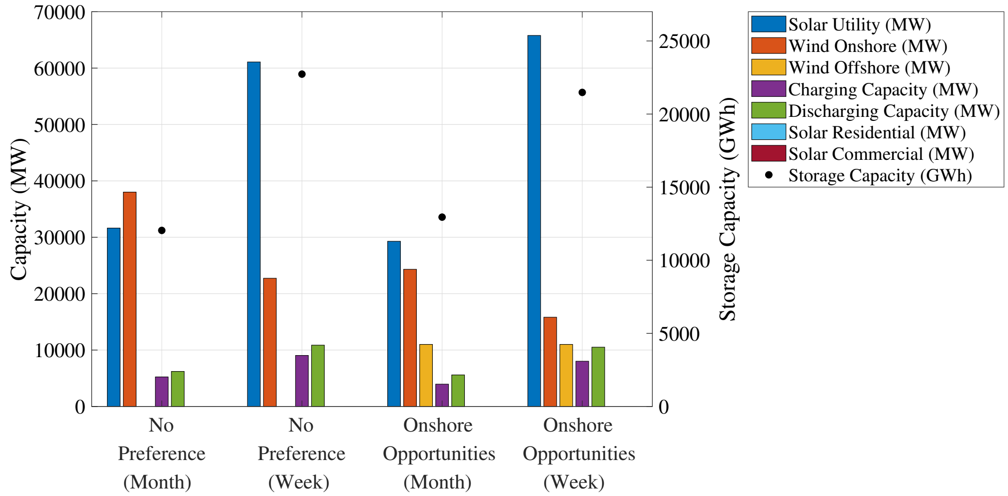

Fig. 6. Timeframe Effect on VRES and Storage Capacity in Two Societal Preference Scenarios

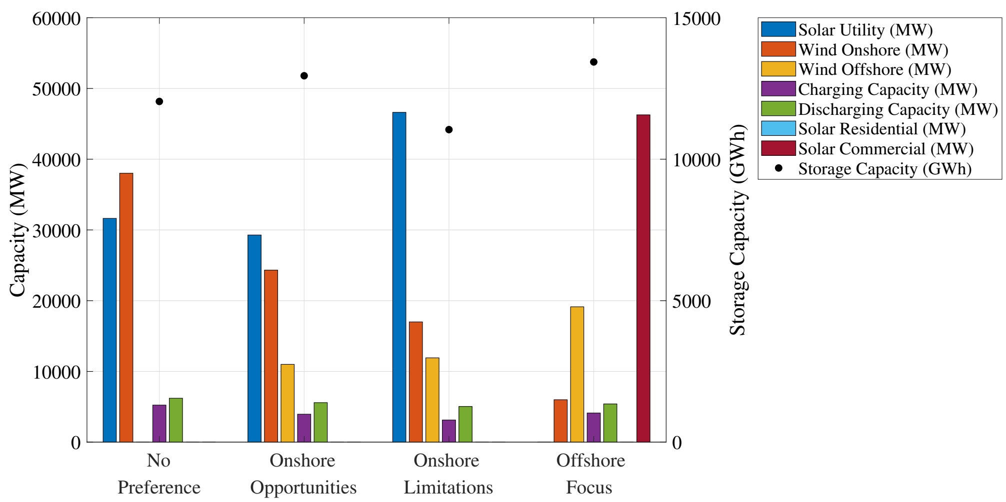

Fig. 7. Monthly Timeframe: Societal Preference Effects on VRES and Storage Capacity

as less fluctuating power sources are already dominant in the initial No Preference scenario.

C. Long-Term Lithium-Ion Battery Storage

Recently lithium-ion battery technology costs have dropped significantly, as widespread use in the automotive sector has lead to strong technological development. Consequently, lithium-ion has been suggested as an energy storage medium numerous times and has actually already seen market implementation. However, as of yet, lithium-ion costs remain high and it is questionable whether this costly technology can compete with large-scale long-term hydrogen storage. To compare the two techniques the costs associated with the development of the Hornsdale Power Reserve in Australia were calculated and found to be 509€/kWh. The technique was offered as an alternative to the hydrogen storage facility (charging, discharging and storage combined) and total costs were calculated. In conclusion, a decrease in costs per kWh of 99% is required before lithium-ion battery storage can compete with hydrogen storage in a monthly timeframe. Where for a weekly timeframe, a cost decrease of over 95% is required, thus hydrogen storage systems are much more cost-effective for long-term storage. Nevertheless, this also indicates where the potential for lithium-ion battery storage lies, which is in short-term storage, as the move towards a smaller timeframe showed improvement for the lithium-ion battery storage case. Future research should look into the short-term storage applications of the hydrogen storage facility and compare total costs here.

V. Conclusions

In conclusion, long-term hydrogen storage can help to achieve energy security for a total cost between 139-177 and 174-211 billion Euros for the monthly and weekly timeframe

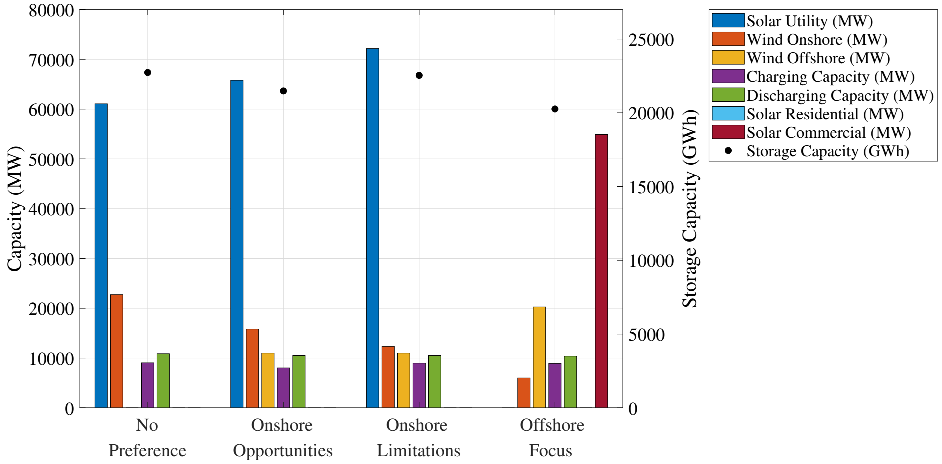

Fig. 8. Weekly Timeframe: Societal Preference Effects on VRES and Storage Capacity

respectively. However, restrictions regarding VRES capacity mixture can drive up the cost. Nevertheless, to a certain extend, limitations with regard to onshore wind capacity can cost-effectively be replaced by utility-scale solar PV. It should be noted that with the worst constraints suggested in this paper, the increase in costs as compared to a non constrained scenario is only 21% and 27% for the weekly and monthly timeframe respectively. Societal preference regarding VRES thus does not necessarily increase the costs too much.

A shorter timeframe increases costs between 20-25% depending on the scenario. The increase in cost is expected, as reviewing a smaller timeframe effectively reduces the short-term storage requirement previously assumed to be freely present. Effectively, some short-term storage is replaced by long-term storage, as compared to the monthly timeframe, and thus some of its costs are now included. Moreover, the preferred VRES power generation method changes, as for a weekly timeframe solar PV generation becomes the dominating source of power production, as compared to onshore wind power generation for the monthly timeframe. Solar PV power production fluctuates considerably less throughout the month, thus making it a more reliable source for weekly load demand coverage and the preferred VRES for power generation.

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