Congestion Relief using Short and Multi-Day Duration Energy Storage Systems

Master Thesis

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By

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Executive Summary

The rapid transition towards a renewable-based electricity system in the Netherlands creates significant challenges for the national transmission grid. With increasing shares of wind and solar power, the variability in generation leads to mismatches between electricity supply and demand, causing congestion and curtailment risks. This thesis investigates to what extent Short-Duration Energy Storage (SDES) and Multi-Day Energy Storage (MDES) technologies can contribute to deferring costly transmission grid expansion while supporting system flexibility.

A quantitative modelling approach was applied using the PyPSA-Eur cost-optimisation framework to simulate a 2040 scenario. In this scenario, the installed renewable generation capacity is optimised such that it can meet an electricity demand that is estimated to be three times higher than 2023 levels. The model optimises investments in generation, transmission, and storage to minimise total system costs.

The modelling results indicate that deploying a combined capacity of $19.4\,TWh$ of SDES and MDES significantly reduces the required expansion of the Dutch transmission grid from $86.2\,GW$ (in a no-storage case) to just $11.8\,GW$. This translates into grid investment savings of €$1\,613$ billion. Annual system costs are also reduced from €$1\ 934$ billion to €321 billion, not only due to avoided transmission investments but also by reducing curtailment, avoiding overdimensioned generation capacity, and improving utilisation of renewable output.

Importantly, the analysis confirms the complementary roles of SDES and MDES. Lithium-ion batteries (SDES) are well-suited for addressing intra-day fluctuations, particularly solar variability, due to their fast response and high power output. In contrast, iron-air batteries (MDES) manage multi-day and seasonal supply deficits, especially aligned with wind variability, by providing long-duration energy storage at lower energy capital costs. The joint deployment of both technologies maximises system efficiency by matching storage characteristics with different forms of renewable variability.

While the quantitative modelling provides valuable system-level insights, its validity is inherently limited by simplifications. A sensitivity analyses was employed to test robustness across a range of technology parameters and shows greater sensitivity to external factors such as grid expansion costs, CO_2 targets, and future demand levels. Moreover, the model abstracts from real-world actor behaviour, regulatory barriers, and market dynamics. To complement these quantitative findings, qualitative interviews were conducted with employees from TenneT and ACM.

The qualitative insights reveal that the ownership and operation of storage assets should primarily rest with market parties, as they can optimise asset utilisation across multiple markets such as the day-ahead or intra-day markets. Allowing Transmission System Operators (TSOs) to directly own storage would likely result in underutilisation, as regulatory restrictions prevent them from participating in energy markets. However, the interviews also identify several persistent barriers to realising large-scale storage deployment for congestion relief. Chief among these are potentially insufficient financial incentives for market actors to prioritise congestion management, complex regulatory requirements to guarantee grid-supportive behaviour without limiting flexibility, and a lack of spatial coordination guiding optimal siting of flexible assets.

The interviews indicate that while the current market structure provides several incentives for the deployment of storage systems, it is unclear whether these incentives are sufficient. If market-driven deployment proves insufficient to deliver the required system-wide flexibility, further regulatory adjustments may be necessary. Policymakers may need to consider targeted incentive schemes that specifically value long-duration storage services, to ensure that the energy mix converges to the most cost-effective one.

The limited scope of the interviews, which did not include market parties or policymakers, leaves important questions unanswered regarding the commercial viability of MDES under the current and future market design. Future research should engage market actors to better understand their willingness to invest in MDES, and explore how regulatory frameworks can be adapted to create viable business models for long-duration storage. In addition, more work is needed to assess how spatial coordination mechanisms can support the optimal siting of both SDES and MDES assets, ensuring their contribution to grid stability and efficient integration of renewable generation.

Keywords: *Battery energy storage, transmission grid expansion deferral, Short-Duration Energy Storage (SDES), Multi-Day Energy Storage (MDES), long-duration energy storage, grid congestion, renewable energy integration*

Contents

List of Abbreviations

Coloured text indicates hyperlinks to the corresponding actor or organisation, where applicable.

Abbreviation	Definition
ACM	Autoriteit Consument en Markt (*Netherlands Authority for Consumers and Markets*)
ACER	European union agency for the Cooperation of Energy Regulators
BESS	Battery Energy Storage System
CapEx	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
DSR	Demand Side Response
DSO	Distribution System Operator
ESS	Energy Storage System
EZK	Ministerie van Economische Zaken (*Ministry of Economic Affairs*)
FOM	Fixed Operating & Maintenance costs
MDES	Multi-day Duration Energy Storage (storage technologies capable of discharging energy continuously for 24 hours or more)
NGO	Non-Governmental Organisation
OAT	One-at-a-time
OpEx	Operational Expenditure
PBL	PlanBureau voor de Leefomgeving (*Netherlands Environmental Assessment Agency*)
PyPSA	Python for Power System Analysis
SDES	Short Duration Energy Storage (storage systems typically discharging energy for up to 4–6 hours)
SoC	State-of-charge
TDTR	Tijdsduurgebonden transportrecht (*Time-bound transmission rights*)
TNO	Nederlandse organisatie voor Toegepast-Natuurwetenschappelijk Onderzoek (*Dutch Organization for Applied Scientific Research*)
TSO	Transmission System Operator
VOM	Variable Operating and Maintenance costs
RTE	Round Trip Efficiency
RVO	Rijksdienst voor Ondernemend Nederland (*Netherlands Enterprise Agency*)

Glossary

Battery: A device that stores energy through electrochemical processes. In this thesis, the term refers to all types of electrochemical storage, including but not limited to short-duration technologies.

Battery Discharge time: The time it takes for a storage technology to release all its stored energy at its maximum rated power capacity. Often used to distinguish between SDES and MDES systems.

Battery Duration: In this thesis, ”battery discharge time” is considered a synonym for ”battery duration”. Due to personal preference, ”battery discharge time” is used in this thesis.

Collocation: The practice of placing an energy storage system at the same site as a generation facility (e.g., wind or solar farm).

Congestion: A condition in the electricity grid where the demand for transmission capacity exceeds the available capacity.

Curtailment: The reduction of output from renewable generators (such as wind or solar) due to grid constraints or oversupply.

Flexible Asset: Any resource (such as energy storage or demand response) that can adjust its output or consumption in response to grid needs, providing system flexibility.

Transmission Grid Expansion: The process of upgrading or adding new transmission infrastructure to increase capacity and improve reliability of the electricity grid.

Intermittency: The characteristic of variable renewable energy sources, such as wind and solar, to produce power inconsistently due to changing weather conditions, leading to challenges in balancing supply and demand.

1 Introduction

1.1 Background

The growing electrification of society and integration of renewable energy, driven by efforts to reduce CO_2 emissions, is placing increasing pressure on electricity grids and exposing challenges in managing supply and demand. Reducing emissions is crucial to prevent global warming and reaching climate goals. To do so, more and more processes and activities are being electrified, which increases the demand for electricity. Besides, the integration of renewable energy farms, such as offshore wind and solar farms, ensures that we can meet this demand in a environmental friendly way. However, the intermittency of these energy sources causes fluctuations in the energy supply, making it harder to predict the supply. The demand is connected to supply via transmission and distribution grids, which should ensure that supply meets the demand. However, these grids experience bottlenecks when the volume of electricity to be transmitted exceeds the grid's capacity. This issue of grid congestion prevents electricity supply from meeting demand, potentially leading to the curtailment of renewable energy farms because of the inability to transport the electricity.

Solving the congestion issue can be done by expanding the grid capacity or increasing grid efficiency. Expanding the capacity can be done by increasing the capacity of grid lines and substations, which is an expensive endeavour. Besides, this increased capacity is not constantly used by the renewable energy suppliers, due to the intermittency of their energy sources. Therefore, reducing the fluctuations in supply and demand via Energy Storage Systems (ESS) can mitigate the need for transmission grid expansion and hence solve the issue of congestion (Bazelaire et al., 2024). Peaks in the electricity supply can be stored and transported during times when the grid is less heavily loaded, hence preventing congestion and ensuring efficient grid usage.

1.2 Literature Review

1.2.1 Energy Storage Systems: Categorisation Based on Duration

Energy Storage Systems (ESSs) play a crucial role in electricity distribution by helping to meet peak energy demand, improving the efficiency of renewable energy integration, ensuring stable power quality, and minimising the expenses associated with expanding distribution networks (Das et al., 2018). A wide range of storage technologies exists, making it essential to group them based on their characteristics to address the diverse requirements of the applications mentioned above.

ESSs are often grouped in five different storage technology types: chemical, electrochemical, mechanical, electrical and thermal storage, as illustrated by Ould Amrouche et al. (2016), Guney and Tepe (2017) and Andrijanovits et al. (2012). Thermochemical storage is seen as sixth storage technology type by Das et al. (2018), yet this type is not widely adopted or commonly referenced in other literature. This method of classification organises technologies by type, suggesting that each category shares broadly similar characteristics, thereby simplifying the process of selecting suitable energy systems for specific applications. However, technical characteristics can vary significantly within these technology type groups. Das et al. (2018) shows that efficiency, (dis)charge time and capital costs are not uniform within the groups.

Another commonly used grouping method is plotting the rated power against stored energy as done by Guney and Tepe (2017) and Wagner (2014), essentially grouping the technologies by their discharge time. This time metric represents the time it takes for the system to fully charge or discharge at maximum power and hence can be used to classify technologies as short-term or long-term storage (Andrijanovits et al., 2012). Next to these classes, Masaud et al. (2010) distinguishes real long-term as an extra classification group. The naming and time framing of these groups are inconsistent across studies, leading to varied definitions. Yet, to enable a reliable energy system based on renewables, we need a diverse mix of storage technologies with various discharge durations.

Table 1.1 shows an overview of the discharge time classifications for various ESSs as proposed by Andrijanovits et al. (2012), Masaud et al. (2010), and Guney and Tepe (2017). The table highlights the inconsistencies in categorisation across different studies, particularly in the classification of batteries. Andrijanovits et al. (2012) identifies them as short-term (seconds/minutes) storage, while Guney and Tepe (2017) categorises them as long-term (minutes/hours) storage. This can be explained by the fact that multiple battery technologies exist, which are all grouped into one classification. Yet, none of these papers classifies them as a multi-day storage solution.

Table 1.1: *Inconsistent ESS classification based on discharge time, comparison of Andrijanovits et al. (2012), Masaud et al. (2010) and Guney and Tepe (2017). The green cells indicate where authors classify specific technologies.*

	Short Term (seconds)			Long-term (minutes)			Long-term (hours)			Real long-term (days)		
	Andrij.	Masau.	Guney	Andrij.	Masau.	Guney	Andrij.	Masau.	Guney	Andrij.	Masau.	Guney
Flywheel		■	■	■	■							
Super caps	■	■	■	■		■						
SMES	■	■	N.A.		■	N.A.			N.A.			N.A.
Batteries	■			■	■	■		■	■			
Hydrogen				■	■			■	■			■
Compressed Air							■		■	■	■	■
Pumped Hydro							■		■	■	■	■

To conclude, classification is often done based on technology type. This causes the technical characteristics within the group to vary significantly. Some studies group the systems based on discharge time, but often overlook individual technologies within these groups. This is problematic when new storage technologies with different characteristics are being developed. These new technologies can lead to a change in classification. For example, as was also shown in Chapter 1, the iron-air battery allows for Multi-day Duration Energy Storage (MDES) in batteries, which is unusual for batteries. However, existing literature still does not recognise batteries as potential for multi-day storage, which limits our understanding regarding these new technologies.

1.2.2 Impact of Energy Storage on Grid Investment Deferral

Scholars agree that ESSs can reduce network expansion costs by reducing the issue of network congestion (Martínez et al., 2024; Virasjoki et al., 2016), though their cost-effectiveness is often bound to specific circumstances. Martínez et al. (2024) states that BESS are a cost-efficient investment under low load growth circumstances, even though they are only used a few days per year for peak shaving.

Cost-efficiency diminishes in high load growth scenarios as the BESS capacity becomes insufficient to support the grid infrastructure. Mallapragada et al. (2020) show a different cost-effective scenario in which (lithium-ion) storage is sized between 4% and 16% of peak electricity demand for various scenarios. Lastly, Spiliotis et al. (2016) show that BESS reduce the total costs of the Distribution System Operator (DSO) by 28%, due to a decreased need for grid expansion investments and fewer curtailment occurrences.

Current studies differ slightly in the application types of BESS and are limited in the fact that only short-duration BESS are included. Martínez et al. (2024) largely focusses on using batteries to smooth peaks at the demand side of the electricity market, whereas Mallapragada et al. (2020) and Gal et al. (2021) utilise batteries to dampen peaks caused by the integration of renewable sources at the supply side. An overview of the studies that assess the impact of ESSs on deferral of grid investments is presented in Table 1.2 and shows the underrepresentation of multi-day duration battery energy storage systems in the literature.

Table 1.2: *Overview of the studies done on the impact of ESSs on deferral of grid investments.*

Author	Energy Storage System	Summary of Impact of Energy Storage System
(Martínez et al., 2024)	BESS (4h lithium-ion)	BESS can defer distribution grid upgrades by absorbing peaks in electricity demand but are only cost-effective under small load growth rates.
(Mallapragada et al., 2020)	BESS (2h, 4h, 8h lithium-ion)	The value of storage increases with a variable renewable energy generation from 40% to 60%, but declines as BESS penetration increases. The long-run value can be lower than current battery technology costs.
(Tsagkou et al., 2017)	BESS (3.6h lithium-ion)	Modular investments are preferred for distribution investment deferral, especially in combination with other services as frequency regulation and energy arbitrage.
(Gal et al., 2021)	BESS (unknown discharge time)	Energy storage can reduce the costs of grid development by locally storing and time-shifting energy that cannot be transmitted due to grid congestion. In the case of Israel, the required additional storage capacity for transmission grid deferral is maximum 170% of the currently installed PV capacity.
(Tarashandeh & Karimi, 2021)	PHS & CAES	ESSs can relieve congestion, thereby deferring investments in new transmission lines.
(Spiliotis et al., 2016)	BESS (unknown discharge time)	Local BESS can defer investments in distribution network expansions by 28% of the total cost of the DSO.

1.2.3 Research Gap

The use of energy storage systems for congestion relief and transmission grid deferral has been widely researched; however, most studies primarily focus on the most adopted battery type: lithium-ion batteries with a discharge time of approximately four hours. These studies rarely consider or quantify the impact of batteries with longer discharge durations (see Table 1.2). This narrow focus may be partly explained by the inconsistent classification of storage technologies (see Table 1.1), as earlier systems typically had fixed and relatively short discharge times.

However, the growing share of renewable energy sources and increased electrification are intensifying the need for a broader range of grid-scale energy storage technologies. Emerging solutions, such as iron-air batteries, enable MDES through the reversible rusting of iron. MDES is particularly promising in addressing multi-day variability in wind power generation, which often involves prolonged windy periods followed by days of low wind.

While recent literature, such as Mantegna et al. (2024), emphasises the importance of properly modelling MDES in deeply decarbonized energy systems, these studies do not systematically assess the combined and comparative impact of SDES and MDES on the deferral of transmission grid expansion investments. This gap is significant because the interaction between SDES and MDES could lead to synergies or trade-offs that are highly relevant for TSOs and policymakers. Moreover, overlooking MDES in techno-economic analyses may hinder informed investment decisions and delay the adoption of promising new storage technologies.

1.3 Research Objective and Questions

This research aims to deliver an assessment of the impact of Short-Duration Energy Storage (SDES) and Multi-day Duration Energy Storage (MDES) technologies on deferring transmission grid expansion investments in the Netherlands. The study utilises desk research to characterise the technological and regulatory landscape of SDES and MDES integration for congestion relief, quantifies their effectiveness in deferring grid investments via a Python for Power System Analysis (PyPSA) model, and employs qualitative research to identify the business implications and remaining implementation barriers associated with MDES technologies.

The scope of this research has been narrowed to focus on the transmission grid of the Dutch energy system under conditions of increased penetration of renewable energy sources. This increased penetration ensures that energy system meets the Dutch climate target of 2030 and makes the outcomes relevant for policy-making, since they represent a near-future state of the energy system. The research focuses on the transmission grid, since Netbeheer Nederland (2019) encourages renewable energy farms to cluster in centralised locations, in order to reduce the need for extensive additional grid infrastructure. Hence, they advocate for larger utility-scale renewable energy farms in our future energy system, which are often connected to the high-voltage transmission grid directly without requiring a connection to the distribution grid. Therefore, this research focuses on deferring transmission grid investments, while neglecting the expansion of the distribution grid. The role of the distribution grid is also acknowledged, particularly in managing the energy influx caused by widespread residential solar adoption. However, the residential energy supply is likely to be a fraction of the utility-scale farms (Netbeheer Nederland, 2023c), hence this research focuses on the deferral of transmission grid investments.

This research seeks to explore the role of energy storage for grid congestion relief by addressing the following main research question:*To what extend can Short-Duration Energy Storage (SDES) and Multi-Day Duration Energy Storage (MDES) technologies defer transmission grid expansion investments in the Netherlands under conditions of increased penetration of renewable energy sources?* The sub-research questions that are used to fill this research gap are:

1. *What are the key characteristics, technological distinctions, and regulatory barriers associated with SDES*

and MDES systems?
This question aims to clarify the technological differences between SDES and MDES systems and to provide a deeper understanding of the advantages and disadvantages of each. In addition, critical parameters such as technology investment costs will be examined, as these serve as input variables for the model used in the next sub-question. Regulatory barriers will also be addressed by identifying the key actors involved in employing Battery Energy Storage Systems (BESS) for congestion relief. All analyses will be conducted through desk research.

2. *How do different energy storage scenarios — SDES, MDES, and a combination – affect the deferral of transmission grid expansion investments under increased renewable energy penetration?*
This sub-question is the core of the research and researches to what extent the storage technologies can defer grid investments. A PyPSA modelling approach is used to answer this sub-question.

3. *How do variations in model input parameters and modelling assumptions influence the outcomes of energy storage scenarios for deferring transmission grid investments?*
This sub-question examines the validity of modelling results by comparing them to other studies, conducting a sensitivity analysis, and discussing the modelling assumptions. The sensitivity analysis allows to determine boundaries in which the results are robust, as will be explained in Chapter 4.4.

4. *What are the business implications and remaining implementation barriers associated with using BESS for grid congestion relief?*
The PyPSA model solely focuses on minimising the total energy system costs, however, other aspects in choosing energy storage systems may play a role as well. This sub-question assesses the business implications of the PyPSA model results by interviewing experts from stakeholders.

1.4 Relevance for Management of Technology

This thesis is closely related to the Management of Technology (MOT) master programme, as it combines both the technological and business perspectives of using Short-Duration Energy Storage (SDES) and Multi-Day Duration Energy Storage (MDES) technologies to defer transmission grid investments. During the programme, I have learned how important it is to not only understand the technical fundamentals of a technology—such as how different battery systems work—but also the business and regulatory environment in which these technologies are implemented.

The programme teaches that most technically advanced solution is not always the most widely adopted. Various barriers can stand in the way, and regulation is one of the factors that can block mass scale adoption of a technology (Ortt & Kamp, 2022). This thesis focuses on both the technology as well as the relevant regulation. This is relevant, since SDES and MDES may be technically capable of deferring grid investments, their actual deployment also depends on the dynamics of the energy market and the roles of different stakeholders. Regulations shape whether batteries can realistically be used for this purpose.

This research, which explores how actors in the energy system might use SDES and MDES technologies to defer grid investments, fits well with the MOT objective of understanding how technology can be used and managed as a strategic resource. It connects the technical capabilities of energy storage to the wider innovation system, and considers both implementation barriers and system-level impact.

1.5 Structure of the Report

Figure 1.1 shows the structure of this thesis. Chapter 2 focuses on the first sub-question by providing a technological characterisation of SDES and MDES systems, discussing their underlying technologies, cost characteristics, and regulatory barriers. The technological characterisation is used as input for the model. The research approach is outlined in Chapter 3. This chapter discusses the setup of the PyPSA-EUR model, the model validation steps as well as the setup of the qualitative interviews. Chapter 4 then discusses the modelling results and determines the influence of SDES and MDES technologies upon grid investment deferral. Besides, it conducts a sensitivity analysis to assess how variations in key input parameters, such as technology costs, and model assumptions influence the model outcomes. Chapter 5 further investigates the regulatory barriers (as identified in Chapter 2) and presents insights gained from expert interviews, discussing the business implications and practical challenges associated with the adoption of these storage technologies. This thesis closes with a discussion (Chapter 6) and conclusions (Chapter 7).

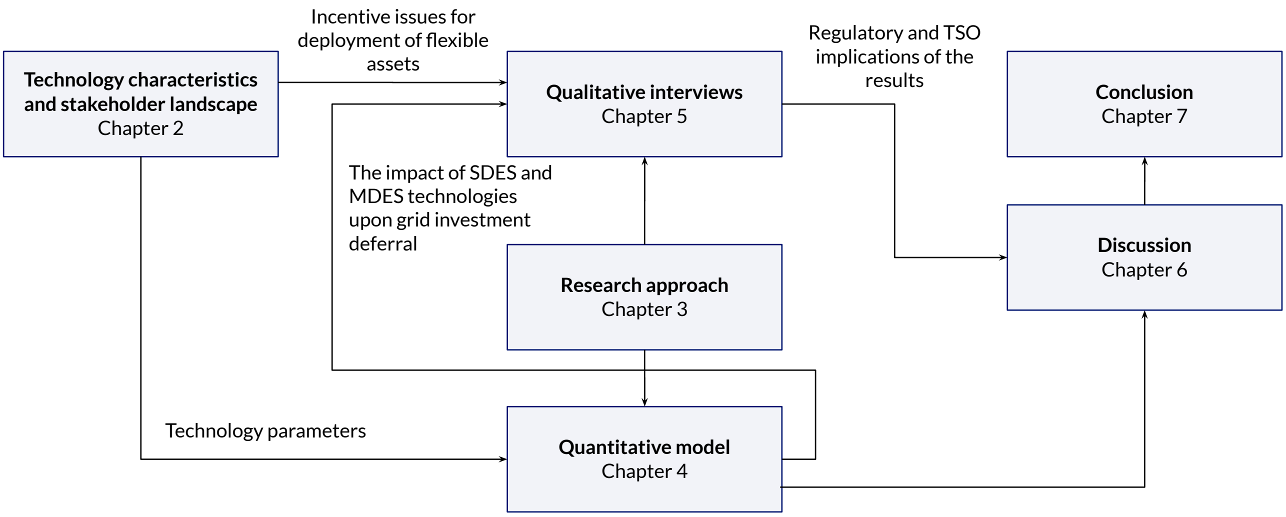

Figure 1.1: Overview of the report structure and flow of results between chapters.

2 Technological and Regulatory Landscape of SDES and MDES Systems

This chapter discusses the key characteristics and technological distinctions between SDES and MDES systems. The chapter begins by analysing the intermittency of renewable energy sources to outline the necessity of both storage technologies. Afterwards, an overview of both SDES and MDES technologies is given. For each category, we select one technology as the most promising technology. Key characteristics of these technologies are discussed, since they serve as important inputs for the PyPSA model that is employed in Chapter 4. The section concludes with an overview of the stakeholders and regulatory barriers for energy storage deployment.

2.1 The Connection Between Battery Discharge Time and the Frequency of Renewable Energy Intermittency

The frequency of the intermittency of renewable energy sources differs per technology, as these technologies are dependent on the weather. Figure 2.1 shows the energy generation of a scenario with three renewable energy farms with an installed capacity of 1 GW each. The plot has been made by utilising the PyPSA-eur software, which determines the generation capacity of renewable energy sources based on weather data (Hoersch et al., 2018). It can be observed that the variations in power output differ between the various technologies. The solar PV technology shows a clear 24-hour pattern, which can be explained by the rotation of the earth. Wind farms show more multi-day generation fluctuations; several days with high wind speeds are followed by multiple days of minimal wind activity.

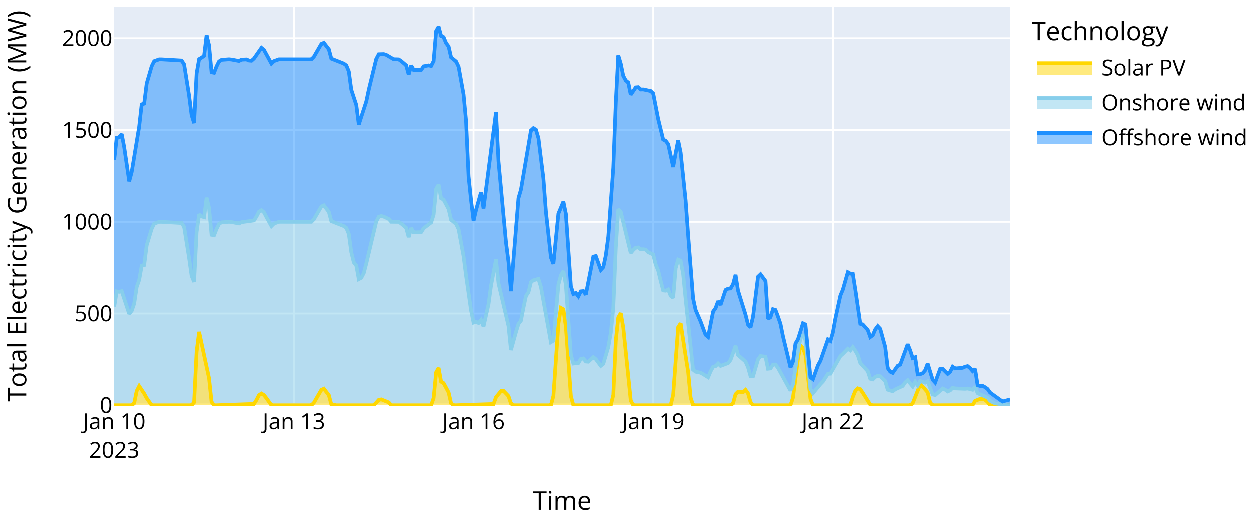

Figure 2.1: Energy generation of fictional renewable energy farms placed in the Netherlands with 1 GW installed capacity each. The energy generation depends on the weather and shows peaks and declines.

The renewable energy farms require grid transmission capacity to transfer the energy, but the required capacity is not constant due to their intermittency. In the case of favourable wind and solar conditions, the energy generation rises which increases the stress on the transmission grid. Without storage, the grid should be capable of transmitting the maximum power output of the renewable energy farms, otherwise energy will be lost. However, during days of low renewable energy generation, less grid capacity is needed. Hence, extending the transmission grid capacity to allow for transferral of the maximum power output of the renewable energy farms is inefficient. Surplus energy can be stored and transmitted during periods of low stress on the grid, which increases grid efficiency. A frequency analysis is employed in the next paragraph to determine which storage type suits best to facilitate this increase in grid efficiency.

Figure 2.2 shows the results of a frequency analysis, which plots the amplitude of the variations in power generation against the frequency of the variations and showcases the need for energy storage solutions with a diverse discharge duration. This analysis ensures that these observations hold over a longer period, since it uses data from the entire year instead of just 15 days in January as seen in Figure 2.1. This data is again fetched from the PyPSA model. A Fast Fourier Transform has been applied, which allows to identify the frequencies that are present in the power output of the renewable energy farms. As described earlier, the 24-hour pattern of solar PV is clearly visible in the graph. The storage of these energy fluctuations advocates for Short-Duration storage, as both charging and discharging should happen within 24 hours.

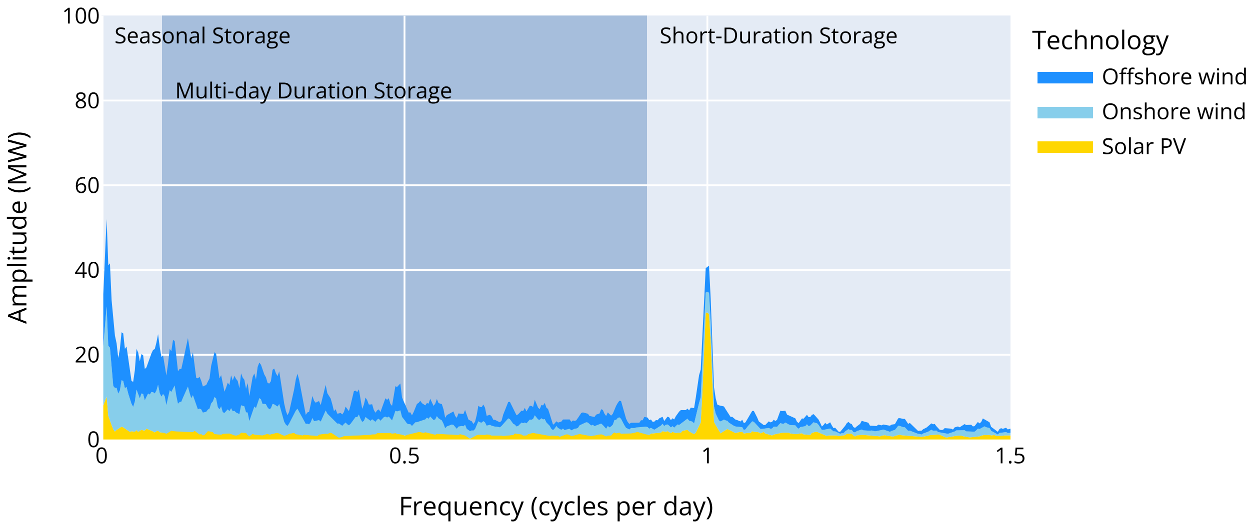

Figure 2.2: Frequency analysis of electricity generation of renewable energy farms with 1 GW installed capacity for each technology, presented in a stacked area plot. The figure plots the amplitude of the fluctuation over its frequency. The analysis shows low frequency components for wind generation, which advocates for Seasonal and Multi-day Duration storage. Solar PV, on the other hand, exhibits mainly 24 hour fluctuations.

Table 2.1 flows from the frequency analysis and shows the share of signal power within three frequency bands: SDES, MDES and seasonal storage. It shows how much the fluctuations in these frequency bands contribute to the total signal power. We observe that 73.1% of the signal power of solar PV can be attributed to short-duration fluctuations. For onshore and offshore wind, this is only 6.6% and 7.5%, respectively. The onshore and offshore wind farms exhibit fluctuations with lower frequency components and hence advocate for the need of Multi-day Duration and even Seasonal Storage. A comparable analysis approach employed by Clerjon and Perdu (2019) shows similar results and the need for both SDES and MDES is also supported in the paper by Woodford et al. (2022).

Table 2.1: *Share of total signal power across storage-relevant frequency bands (Seasonal Storage, MDES, SDES) derived from the FFT analysis of normalised power output time series of 1 GW solar PV, onshore wind, and offshore wind generators. Note that the typical duration for SDES is often much shorter (2 to 8 hours); however, for the table below, we have chosen to extend it so that all categories are sequentially connected.*

Technology	**Seasonal Storage** > 240 hours	**MDES** 26 - 240 hours	**SDES** < 26 hours
Solar PV	9.4%	5.3%	85.3%
Onshore wind	43.4%	47.3%	9.3%
Offshore wind	37.5%	52.2%	10.3%

Effective storage requires the discharge time of the battery system to match with the frequency of the fluctuations of the power output that is to be stored and discharged. Batteries have a fixed maximum capacity and maximum power output. The capacity over power ratio is called the discharge time and represents the time it takes to discharge the battery from 100% to 0% at full power. Effective sizing of the battery system is such that the battery can charge to full capacity at full power, and fully discharge at the same rate immediately after. Hence, all battery capacity and power is being used. To do so, the battery discharge time must match with the frequency of the fluctuations of the energy to be stored by following Equation 1. For example, a battery with a discharge time of 12 hours would be optimal to store fluctuations with a frequency of 1 cycle per day, as this allows to charge and discharge at maximum power and capacity.

$$\text{Battery discharge time [h]} = \frac{0.5 \cdot 24}{\text{Frequency of fluctuations to be stored [cycles per day]}} \tag{1}$$

The existence of low frequency components in the frequency analysis of the renewable energy farm output (Fig. 2.2) implies the need for multi-day storage. Efficiently sized storage should have discharge times that match with these frequencies, roughly in between 13 to 125 hours. Yet, the high-frequency solar PV peak demands short-duration storage, i.e. energy storage systems with a discharge time below 13 hours. Therefore, both SDES and MDES systems are needed to effectively store the energy generated via wind and solar farms.

A similar frequency analysis approach could in principle also be applied to the demand side of the energy system, such as industrial electricity consumption or general load patterns. Like renewable generation, electricity demand exhibits fluctuations over different time scales, including daily, weekly, and seasonal cycles, which can be characterised in terms of their frequency components. However, this study deliberately did not investigate these demand-side characteristics. The reason lies in the nature of the energy transition itself: the shift from conventional generators to renewable energy sources introduces new challenges primarily on the supply side, as the intermittency of renewables represents a novel phenomenon compared to the largely controllable output of conventional power plants. In contrast, the demand side of the electricity system remains relatively unaffected in terms of its underlying fluctuation patterns, and thus does not introduce new frequency characteristics as a consequence of the transition.

Consequently, the focus of this work has been placed on understanding and addressing the supply-side intermittency introduced by renewable energy sources.

2.2 Short-Duration Energy Storage Technologies

This chapter provides an overview of key SDES battery technologies, highlighting their advantages and limitations for grid-scale applications. By comparing these technologies, we determine the most suitable option for grid storage applications. Afterwards, key characteristics of this technology are discussed, since these characteristics are used in the modelling phase discussed in Chapter 4.

2.2.1 Overview of Short-Duration Energy Storage Technologies

Table 2.2 shows that various battery technologies fall under the SDES classification and that their characteristics vary significantly. Lithium-ion, NaS, and NiMH technologies are considered high-cost, whereas lead acid and lithium-air technologies are low-cost alternatives. The latter technology has an even higher energy density than lithium-ion, however, it is still very immature. This is a disadvantage compared to the other technologies as their supply chains and performance records have already been established and are well known. Lead acid can be considered a low-cost, mature alternative but it has disadvantages, such as low specific energy, short shelf life and the presence of toxic substances.

Table 2.2: Overview of Short-Duration Energy Storage (SDES) Battery Technologies.

Battery Technology	Positive Aspects	Negative Aspects
Lead Acid	• Mature, low-cost technology [1] • Available in large quantities with various sizes/designs [2] • High recyclability of battery components [2]	• Contains toxic substances [1] • Short shelf life [1] • Low specific energy [1]
Lithium-ion	• High energy density [1] • Rapid charge capability [2] • Long cycle & shelf life [2] • Broad operational range [2] • Widely applied in mobile & stationary applications [3]	• Relatively high cost [1] • Poor recyclability [2]
Lithium-air	• Higher energy density than lithium-ion [1] • Non-toxic [1] • Low cost [1]	• Immature technology [1]
NaS	• Relatively long cycle life [2] • High energy density [2]	• High cost [2] • High working temperature [2]
NiCd	• Long cycle life [2] • Low maintenance [2]	• Contains toxic and caustic elements [2]
NiMH	• Relatively high energy density [2] • Long cycle and shelf life [2] • Environmentally acceptable, recyclable materials [2]	• Relatively high cost [2]

[1] Data from Rahman et al. (2022), [2] Data from Fan et al. (2020), [3] Data from Sahoo and Timmann (2023).

Several key factors are of importance for SDES technologies to be suitable for renewable energy storage. Storage systems with small capacities are considered irrelevant for storing energy from renewable energy systems (Andrijanovits et al., 2012; Guney & Tepe, 2017). Other important factors are low power capital costs, high power and efficiency ratings, fast response, long lifetime and fast charging time (Das et al., 2018). These factors are taken into account during the selection of the most suitable technology for grid storage applications.

Lithium-ion technology is regarded as the optimal SDES battery technology for grid-scale applications, as its characteristics largely align with the requirements discussed above. It offers high energy density, high power and efficiency ratings, fast response, fast charging times, and a long lifespan. Its only drawback is the high power capital costs. Nevertheless, lithium-ion technology is considered a key component in facilitating the integration of renewable energy sources into the grid (Chen et al., 2020), and hence the remainder of this research will focus on lithium-ion as optimal SDES battery technology.

2.2.2 Key Characteristics Lithium-Ion Batteries

The CapEx, Fixed Operating and Maintenance costs (FOM), Round Trip Efficiency (RTE) and lifetime are of importance for a successful representation of the battery in the PyPSA model. Hence, these characteristics are deemed the key characteristics of lithium-ion and discussed in this chapter. The CapEx refers to the total installed project costs, including installation and grid integration. The FOM costs are expressed as a percentage of the CapEx per year. They account for any operating costs that are fixed, and hence not dependent on the amount of energy charged and discharged into the battery. Values for these parameters are discussed below and derived by comparing sources via desk research.

Figure 2.3 shows how various factors influence the total cost of a grid-scale lithium-ion storage project. It can be observed that the cost projections vary over time; costs can be influenced by factors such as increased global manufacturing or raw material prices (IRENA, 2024). Besides, the discharge time influences the total project costs, since batteries with a shorter discharge time require more expensive high-power components. Lastly, the differences in estimated total costs can be caused by the use of varying data sources and modelling approaches across studies.

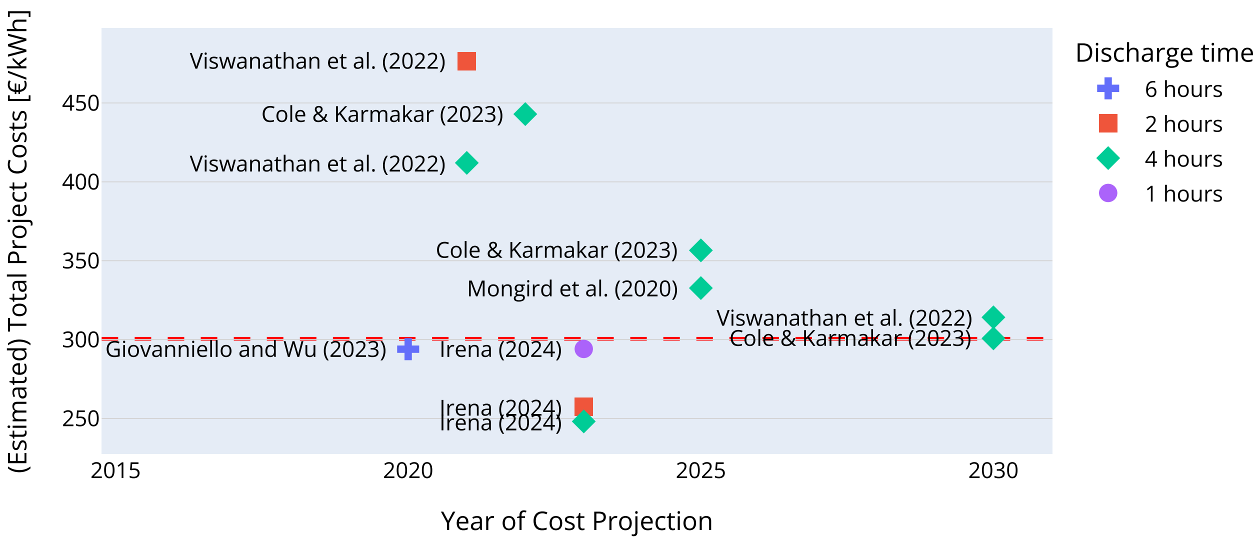

Figure 2.3: Overview of (estimated) total project CapEx for lithium-ion grid-scale storage.

To establish a final value for the total lithium-ion project costs, the average of the projections by IRENA (2024) and estimates for 2025 and beyond are used, thus excluding all projections from before 2022. This is done because the research focuses on a future state of the energy system with increased renewable penetration. As a result, historical values are deemed irrelevant. One could argue that using 2030 estimates alone would be even more suitable, given this focus on the future state. However, it is important to acknowledge that current technology costs influence that future state, making them highly relevant. The inclusion of the current price projections of IRENA (2024) is done to improve accuracy, since these projections rely on existing data and historical trends rather than future assumptions and models used to determine these estimates.

The literature review revealed that the variation in values for other key characteristics is significantly smaller. The final selected values are presented in Table 2.3, while a comprehensive comparison can be found in Appendix C, Figure C.1.

Table 2.3: *Key characteristics of grid-scale lithium-ion storage*

Characteristic	Value	Unit	Source
Total project CapEx	300.15	€/kWh	See Fig. 2.3
Round Trip Efficiency	84.55	%	See Fig. C.1
Fixed Operating & Maintenance costs	0.35	% / year	See Fig. C.1
Lifetime	12	years	See Fig. C.1

2.3 Multi-day Duration Energy Storage Technologies

This chapter provides a comparable overview and analysis to the previous chapter, but now focuses on energy technologies suitable for multi-day storage. It includes an overview of existing technologies and examines the key characteristics of the most promising MDES technology.

2.3.1 Overview of Multi-day Duration Energy Storage Technologies

Literature shows that the potential MDES battery technologies are limited to metal-air and redox-flow technologies, each with distinct characteristics. An overview is presented in Table 2.4. The metal-air technology has been around since 1878, but significant technical barriers such as corrosion and inefficiencies have hindered large-scale diffusion (Olabi et al., 2021). These issues made other battery technologies, such as lithium-ion, more commercially available. Metal-air technologies regained attention due to their potential to offer high energy density, cost-effective, and safe energy storage (Wang et al., 2019). The redox-flow technology, on the other hand, is a developed technology that offers high efficiencies. Other strong aspects are its strong modularity, easy transportability and scalability. Downsides are its relatively high energy cost compared to metal-air and significant space requirement.

The requirements for MDES integration with renewable energy systems largely overlap with the requirements for SDES systems, as mentioned in Chapter 2.2.1. However, there is a greater emphasis on energy capacity costs for long-duration storage. For a storage resource to be economically viable for multi-day storage, the energy capacity cost should be approximately $20/kWh, while seasonal energy shifting requires a cost of around $1/kWh (Mantegna et al., 2024). This is primarily because systems with longer discharge durations can perform fewer charge-discharge cycles, thereby reducing potential revenue.

Metal-air batteries align better with the MDES requirements, due to their lower energy capital cost. Their energy capital cost is in the range of 10-60 $/kWh, whereas the costs for redox-flow are often between 150 and 1000 $/kWh (Argyrou et al., 2018). One of the promising metal-air technologies is the iron-air battery technology. It is known for its abundance of raw materials, environmental friendliness, and cheap cost (Olabi et al., 2021). Besides, research shows that iron-air is a potential option for large-scale, long-term energy storage (Woodford et al., 2022). Hence, the remainder of this research will focus on iron-air as optimal MDES battery storage technology.

Table 2.4: Overview of Medium-Duration Energy Storage (MDES) Battery Technologies

Battery Technology	Positive Aspects	Negative Aspects
Metal-air	• Low energy capital costs [1] • High energy density [4] • High level of safety [4]	• Technology is developing [1] • Low energy efficiency (±50%) [1] • Relatively low cycle life [1]
Redox-Flow	• Strong modularity, easy transportability and scalability [3] • High efficiency [3] • Economies of scale make them cost-effective, allowing applications from kW to MW range [3]	• Relatively high energy costs (compared to metal-air) [1] • Requirement of large space [2]

[1] Data from Argyrou et al. (2018), [2] Data from Fan et al. (2020), [3] Data from Sahoo and Timmann (2023), [4] Data from Wang et al. (2019).

2.3.2 Key Characteristics Iron-Air Batteries

The cost characteristics of iron-air batteries are presented in Figure 2.4. Scientific literature typically provides only broad ranges, likely because the technology has not yet been widely adopted. This makes it challenging to determine accurate cost estimates, as factors such as economies of scale and learning curves must be taken into account. Exact figures are available from battery developers (Form Energy, 2023; Ore Energy, 2025) and consultancy reports produced in collaboration with industry stakeholders (McKinsey and Company, 2021). However, these sources may introduce bias, as they may not be entirely impartial. Nevertheless, their projected capital costs fall within the range given by Argyrou et al. (2018) and Narayanan et al. (2012) and are therefore considered realistic. A final value for the estimated CapEx for iron-air batteries is found by averaging the cost projections from 2025 and beyond. This selection has been used for similar reasons as discussed in Chapter 2.2.1.

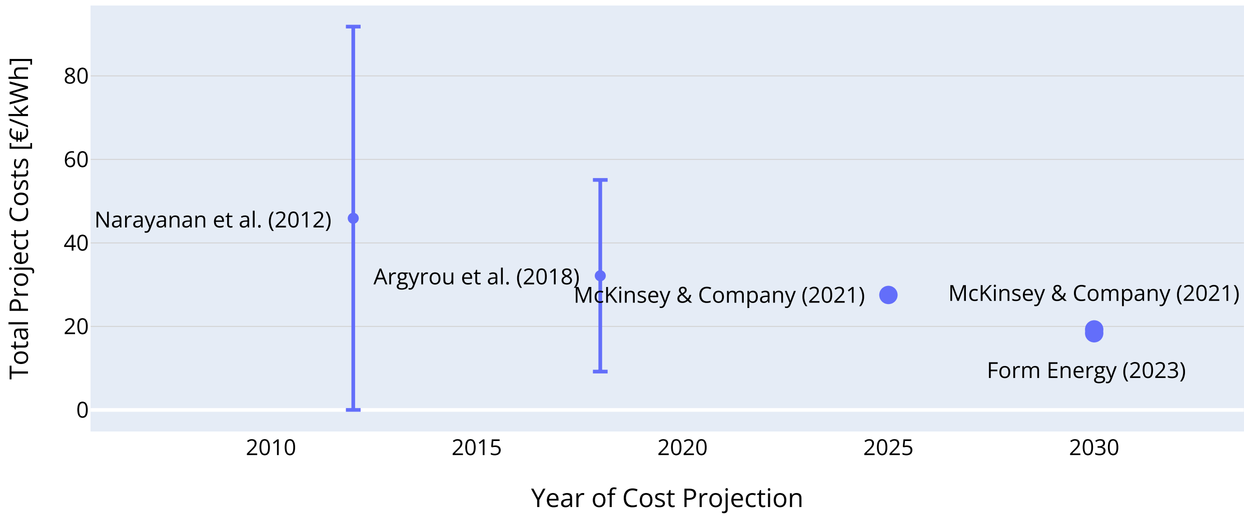

Figure 2.4: *Total project CapEx for iron-air storage. The red dotted line represents the final value that is determined by averaging the cost projections from 2025 and beyond. Please see Confidential Appendix A for the full version of this graph.*

The final values for the key characteristics of iron-air battery storage are presented in Table 2.5, whereas the full comparison can be observed in Figure C.2 in Appendix C. Important to note is that the iron-air technology has not been widely adopted. This may influence the results shown in the table, since characteristics must be estimated with data that is currently available, for example from lab or pilot testing. The actual characteristics of the technology, once it has been diffused at large-scale, may differ from these estimates.

Table 2.5: *Key characteristics of grid-scale iron-air storage. Please see Confidential Appendix A for the full version of this table.*

Characteristic	Value	Unit	Source
Total project CapEx	Confidential	€/kWh	See Fig. 2.4
Round Trip Efficiency	Confidential	%	See Fig. C.2
Fixed Operating & Maintenance costs	Confidential	% / year	See Fig. C.2
Lifetime	Confidential	years	See Fig. C.2

2.4 Stakeholder Analysis for Energy Storage Deployment

The integration of energy storage solutions into the Dutch electricity system requires the involvement of several stakeholders. This section outlines the key actors relevant to the deployment of energy storage and examines their roles within the broader energy system landscape. It also discusses which actor is responsible for installing these flexible assets, along with the associated incentive and regulatory challenges. Lastly, a power-interest matrix has been employed to identify the most influential stakeholders with whom close engagement is vital to overcome the aforementioned barriers.

2.4.1 Stakeholder overview

Grid Operators (TSOs and DSOs) Grid operators are responsible for the transmission of electricity between supply and demand. In the Netherlands, the electricity market is fully regulated, with TenneT serving as the sole Transmission System Operator (TSO) and regional Distribution System Operators (DSOs) – such as Liander, Stedin, and Enexis – operating exclusively in their own regions. The responsibilities of grid operators include connecting producers and consumers to the grid in a non-discriminatory manner. This implies that every customer must be treated equally, and that prioritisation – regardless of potential benefits to the TSO – is not allowed. Other responsibilities of grid operators are: maintaining grid reliability, and expanding infrastructure to meet future demand (Netbeheer Nederland, 2019). Additionally, the TSO is uniquely responsible for ensuring the continuous balance between electricity supply and demand. Storage technologies are a great tool to facilitate this balance, however current regulation prevents TSOs and DSOs from the storage of energy. Exemptions to this regulation can be granted by the ACM (Van Den Boom, 2023).

Regulators The Autoriteit Consument en Markt (ACM) is the national regulatory authority responsible for overseeing the activities of grid operators in the Netherlands. As the market lacks competition, ACM plays a crucial role in guaranteeing efficiency and fairness. It supervises both the TSO and the regional DSOs, by evaluating their performance to ensure they operate cost-effectively. One of ACM's functions is to compare DSOs with eachother as a benchmark for operational efficiency. In addition, ACM sets the maximum tariffs that grid operators can charge for electricity transport, thereby limiting excessive costs to end-users (Netbeheer Nederland, 2019). Lastly, ACM also protects consumer rights. ACM is part of ACER, the European cooperation of energy regulators. Hence, ACER can be identified as stakeholder as well, however with decreased influence. The primary role of ACM is to test if the grid operators obey to the national and European legislation. In certain cases, the law permits ACM to grant certain exemptions. Next to this, ACM can define codes in which additional rules for actors in the energy system are specified.

Governments and policy-makers The Dutch parliament is responsible for the creation of new legislation. The Ministry of Economic Affairs (EZK) holds formal authority over economic policy issues, including the development of energy policies (Van Rooijen & Van Wees, 2006). In addition, the Ministry of Finance is responsible for the establishment and approval of the overall government budget. This ministry is also involved when fiscal instruments are implemented (Van Rooijen & Van Wees, 2006). The Netherlands Enterprise Agency (RVO) oversees the allocation of subsidies, but only under the directions of the ministries. All legislation must comply with EU directives; therefore, the EU can also be identified as a stakeholder. The creation of new legislation is a time-consuming process that often begins only after problems are observed, which may pose a barrier when immediate action is required.

Public NGOs Several Non-Governmental Organisations (NGOs) with differing objectives operate within the energy system landscape. Firstly, NGOs can influence the policy process through lobbying, though the role of environmental NGOs in policy making has been relatively limited (Van Rooijen & Van Wees, 2006). Secondly, NGOs such as Netbeheer Nederland aim to improve communication between grid operators and represent their interests to other stakeholders. Lastly, organisations such as TNO and the

Planbureau voor de Leefomgeving (PBL) conduct research on environmental issues and related policies, providing advice to the government.

Energy Market Participants From the grid operator's standpoint, all entities in this actor group interact with the grid as users of its infrastructure. First, it includes energy producers - companies such as Nuon and Essent - that generate electricity using (renewable) sources, including wind farms or combined cycle gas turbine (CCGT) plants. Second, energy suppliers are part of this actor group. Companies, like Eneco and BudgetEnergie, are responsible for purchasing electricity from producers and selling it to end-users. Some companies, such as Eneco and Essent, function as both producers and suppliers. Lastly, energy consumers are included in this group, representing end-users such as industries or households. This entire group of actors operates within a liberalised market, which grants them fundamental market freedoms which are discussed below (TenneT, n.d.-b).

1. Freedom of Dispatch: generators and consumers have the right to produce or consume the amount of electricity that they choose, within the limits of their connection and the contractual limits of their connection agreement.
2. Freedom of Transaction: market parties can enter into any form of contractual agreements with regard to their demand and supply.
3. Freedom of Connection: all demand and supply resources can connect into the grid on a non-discriminatory manner (e.g. independent of location).

2.4.2 Challenges in Incentivising Energy Storage Integration for Grid Congestion Relief

The integration of renewable energy sources into the Dutch electricity grid can be enhanced through the use of flexible assets such as batteries, which help to address the intermittency of these energy sources. However, various incentive-related challenges and legal barriers hinder the deployment of such assets, as will be discussed below.

The rights of Energy Market Participants do not incentivise this actor group to offer flexibility or invest into flexible assets such as Energy Storage Systems. Their freedom of dispatch and freedom of connection implies that grid operators are not permitted to discriminate and are obligated to connect all users to the grid, even if the requested location or electricity production/consumption is suboptimal for the grid operator. For example, energy producers may select rural areas with relatively inexpensive land to place their renewable energy farm, however the grid capacity in these locations is often limited (Netbeheer Nederland, 2019). Next to that, renewable energy producers contribute to large fluctuations in supply, yet they have the right to produce any amount of electricity they choose. Energy market participants are not obligated to offer flexibility and grid operators cannot prioritise projects that they favour, for example because of location. However, the ACM has introduced exemptions to this rule, allowing grid operators to prioritise projects that contribute to resolving congestion issues (ACM, 2023). This is a good start, however these projects are not always profitable which decreases the interest from the market to install these, as will be discussed in the next paragraphs. The burden to deal with flexibility is therefore shifted back onto grid operators.

The TSO is responsible for maintaining balance in the electricity market and can determine the means by which this is achieved, as long as they act within the limits of the law. Storage facilities are a great balancing tool, however currently grid operators are prohibited from owning storage facilities unless specific exemptions are granted by the ACM. Therefore, an electricity market design combining a spot and imbalance market has been established to incentivise the free market to address these imbalance issues (Tanrisever et al., 2015). This approach worked well for energy systems with a low penetration of renewable energy generators, as generation from conventional sources is largely predictable and can be planned in advance. However, this has become increasingly challenging with the rising share of renewable energy sources in the energy system. More flexible assets are required to effectively integrate these sources, but current instruments do not sufficiently incentivize market parties to install and use such assets to prevent congestion (Van Den Boom, 2023). As a result, energy prices have become highly volatile, renewable energy sources must be curtailed, and grid capacity must be expanded to facilitate the transport of peaks in supply and demand.

A possible explanation for the insufficiency of current instruments in incentivising market parties to install flexible assets is provided by Van Den Boom (2023). Storage solutions such as batteries only alleviate congestion when charged and discharged at appropriate times; otherwise, they may worsen the issue. However, to maximise the return on battery investments, it is important for market parties to operate these batteries on imbalance and other energy markets. Relying solely on batteries used for congestion management and enhancing grid transmission capacity without participation in the energy markets is unlikely to be profitable. Consequently, there is limited interest from market participants in installing batteries exclusively for congestion management purposes.

To solve this issue policy-makers and regulators can properly incentivise market parties to install flexible assets for congestion relief. Another option is to grant exemptions for the TSOs to operate batteries, as they already have an incentive to install them – namely, their responsibility to manage the balance in the transmission grid.

2.4.3 Identifying Key Stakeholders via the Power-Interest Matrix

To further analyse the role of each stakeholder in resolving the incentive and regulatory challenges around energy storage, a Power-Interest Matrix has been applied. Building on the approach initially described by Mendelow (1981), this matrix helps us to identify which stakeholders require close attention and engagement in order to remove the barriers around energy storage deployment. To create the matrix, a list of actors and their power and interest has to be known. Information from the sections above is used to assess each actor's ability to influence the rules of the game (power) and their level of concern or investment in seeing congestion alleviated and energy storage deployed (interest).

Energy Market Participants have a mid-level interest because curtailment directly impacts their revenue streams, yet they face insufficient financial drivers to install storage solutions. Their power is moderate, as they generally abide by market rules set by regulators and policy-makers and have to obey to the grid operators when it comes to queuing rules for new grid connections. Grid Operators demonstrate high interest, since they bear direct responsibility for system balance and congestion management. Nevertheless, they possess less regulatory power than government institutions and regulators — who define the legislative framework within which grid operators must operate. Public NGOs tend to have a relatively limited role in policy-making since their ability to shape regulations (and thereby power) is smaller compared to governmental bodies (Van Rooijen & Van Wees, 2006). They exhibit high

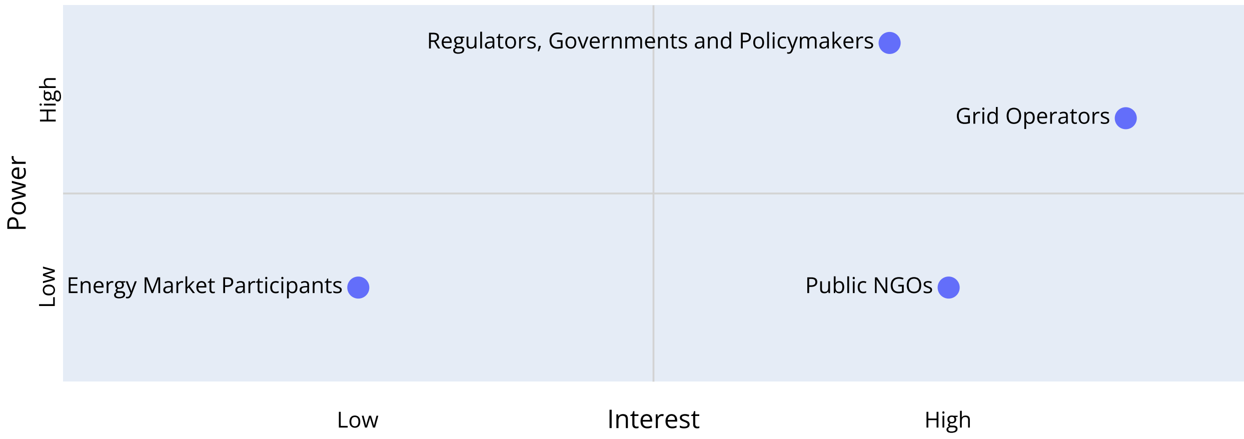

Figure 2.5: *Power-Interest matrix for implementation of Energy Storage Systems to be used for grid congestion relief.*

interest since these NGOs are often groups of actors with the same issue, for example Netbeheer Nederland which is an association for grid operators. Lastly, Regulators and Government and Policy-makers occupy a position of high power, as they establish the rules and design the playing field. Their interest in resolving grid congestion is considerable, but not as acute as that of the grid operators, whose core function is maintaining system reliability.

From this assessment, it becomes clear that grid operators, regulators and government/policy-makers can be categorised as having both substantial power and a high degree of interest. Hence, these parties must be closely engaged to overcome current incentive and regulatory barriers for energy storage deployment to be used for congestion relief. Consequently, these stakeholder groups will be approached for interviews to address the business implications for energy storage as outlined in the fourth sub-question.

3 Research Approach

This chapter describes the approach used to answer the second and third sub-question via a Python model. It starts with the definition of the policy and modelling question, followed by modelling implementation details, and closes with the identification of the system boundaries and modelling assumptions.

3.1 Policy and Modelling Question

Knowing how SDES and MDES technologies can influence grid investment deferral, gives insight into the composition of a cost-effective future energy system. This knowledge can be used by policymakers to ensure their regulations favour such a cost-effective system. This especially relevant during the transition phase to an energy system fully reliant on renewable energy sources, since this requires the installation of storage technologies to deal with the intermittency of these energy sources, as previously discussed in Chapter 2.1. Which storage technologies to use and how these may influence required transmission grid expansion is vital information for policymakers and grid operators, such that they can assure a cost-effective, stable energy system fully reliant on renewable energy sources.

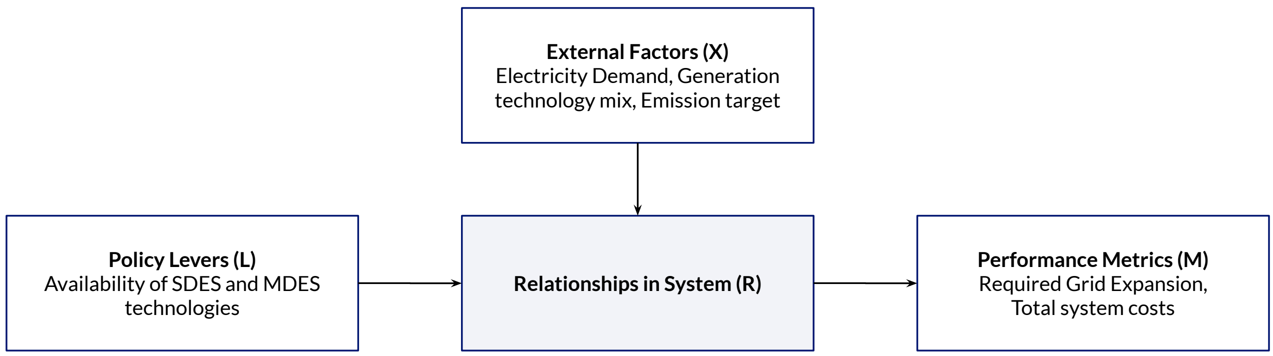

Figure 3.1: *Modelling question presented in XLRM framework (Lempert et al., 2003).*

Figure 3.1 shows the modelling question conform the XLRM framework (Lempert et al., 2003). In this framework, the policy levers (L) represent the decisions under the modeller's control — in this case, the inclusion and deployment level of SDES and MDES technologies in the Dutch electricity system. We assume that the implementation of these technologies is under our control, since policy instruments can be used to facilitate or block the implementation of these technologies, when necessary. The external factors (X) include uncertain elements such as future electricity demand, the renewable generation mix, weather variability (which affects generation and load profiles), and CO_2 emission targets. These are outside the scope of direct control but may significantly influence the outcomes. The CO_2 target is considered to be fixed, since this has been set in the European Climate Law. The performance metrics (M) by which scenarios are evaluated are the total system cost and the extent of required transmission grid expansion. Lastly, the relationships (R) are represented by the PyPSA-EUR model itself, which captures the techno-economic interactions between the technologies and elements in the electricity system. This results in the following modelling question: *"What is the impact of the availability of SDES* *and MDES technologies (L) on total system costs and the need for transmission grid expansion (M), given the external factors (X) and the dynamics of the electricity system as simulated in PyPSA-Eur (R)?"*

3.2 Modelling Framework and Implementation Details

Whether SDES and MDES technologies can defer transmission grid investments depends on the interactions between policy levers, external factors, and system relationships. For each possible configuration of storage availability (L), given the external conditions (X), we aim to determine the most desirable system outcome in terms of minimising total energy system costs (M). This requires identifying the cost-effective mix of generation, storage, and transmission infrastructure that satisfies all system constraints. The problem is inherently an optimisation problem, since it involves finding the best solution among a large number of possible system configurations, given a set of inputs and constraints. Therefore, we use an optimisation algorithm to determine the most cost-effective energy system configuration for each configuration scenario.

The PyPSA-EUR (Hoersch et al., 2018) Python framework is a cost optimisation model that can be used to assesses the impact of SDES and MDES upon transmission grid investments. PyPSA is an open-source software library that allows to simulate and optimise power systems. It uses several input parameters to calculate the most cost-effective energy mix, while meeting certain constraints such as ensuring that supply meets demand. The most cost-effective power system is calculated by minimising both capital expenditure (CapEx) and operational expenditure (OpEx). It allows for the inclusion or exclusion of various technologies in the model, hence several scenarios can be simulated which allows to determine the impact of storage technologies upon the total energy system costs. A schematic overview of the PyPsa workflow is presented in Figure 3.2. A more in-depth analysis of the modelling approach follows in the chapters below.

This study builds upon the existing PyPSA-EUR framework by tailoring it to simulate SDES and MDES storage deployment scenarios. While the core optimisation model was already available, my contribution consisted of selecting the appropriate input parameters (step 1 in Figure 3.2) to reflect realistic system conditions. As the input parameters have a substantial impact on the modelling outcomes, they were retrieved with precision, as detailed in Chapter 3.5.

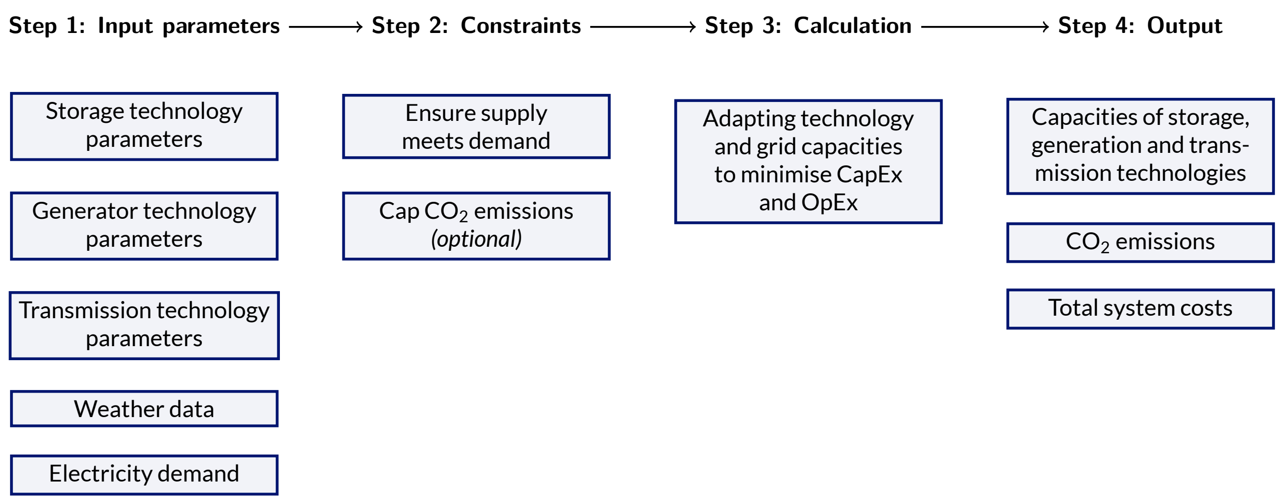

Figure 3.2: *Visualisation of inputs and outputs of the PyPSA model.*

Nodes

In PyPSA, all calculations are performed on a node basis. Nodes represent geographical locations where supply, demand, and storage technologies interact. Input parameters – such as weather data for renewable generation and electricity demand profiles – are assigned to these nodes and the optimal generation and storage capacity are calculated for that node, as illustrated in Figure 3.3. By modelling the system at the nodal level rather than at every specific point in space, PyPSA reduces the spatial resolution of the problem. This is done to simplify the optimisation process and ensures that the model converges to the optimal solution within reasonable computation times. The number of nodes can influence the results, as a simulation with more nodes has a higher spatial resolution. Figure C.7 in the Appendix shows how the number of nodes affects the simulation results. Our simulation uses 55 nodes, the highest level of spatial resolution provided by PyPSA-Eur for the Dutch electricity grid.

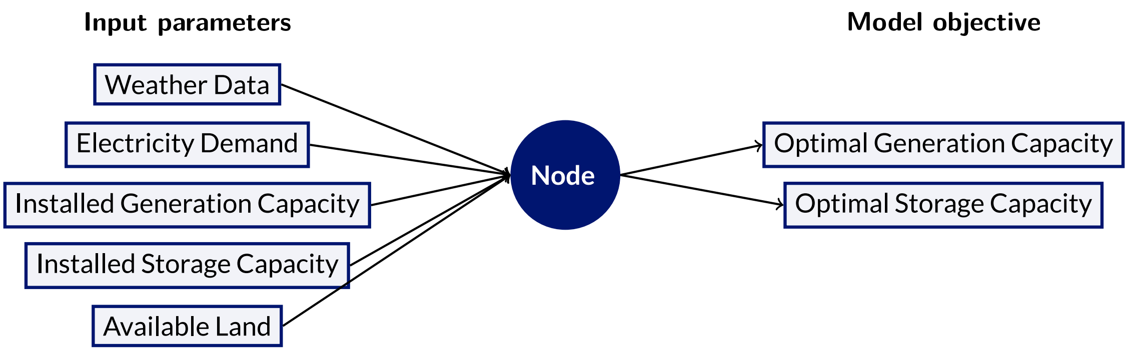

Figure 3.3: Representation of a PyPSA node with inputs and optimized outputs.

Battery model

PyPSA allows to model storage technologies by utilising fundamental components: a charger *link*, a *store* and a discharger *link* (see Figure 3.4). The two *links* connect to a node and ensure that the electricity can flow from the grid into the *store* element of the battery. Constraints are added that set the ratio of the power between these two *link* elements. For lithium-ion batteries, it is assumed that the input power ($p_{0,\text{charger}}$) is equal to the output power ($p_{1,\text{discharger}}$) (Hoersch et al., 2018). To finish the battery model by utilising two *links* and a *store* element, a last constraint is added which ensures that the size of the *store* scales linearly with the input power, following: $e_{\text{nom}} = p_{0,\text{charger}} \cdot$ discharge time. This ensures that batteries stick to their capacity-power ratio, which results in their characteristic discharge time. This approach, as also described by PyPSA (n.d.-a), allows the model to determine the optimal storage capacity, while the constraints ensure that the charger and discharger power follow from this optimal capacity.

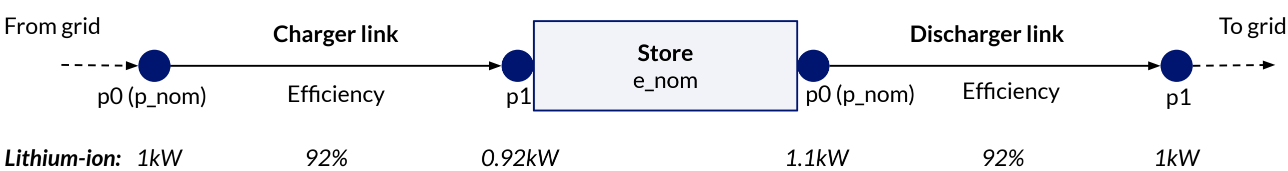

Figure 3.4: Schematic overview of battery model in PyPSA. A full version of this schematic is available in Confidential Appendix A.

Transmission Lines and Multiple Nodes

Nodes can be connected via lines which represent the high-voltage transmission grid. A representation of the electricity grid can be created by modelling multiple nodes, in which electricity can flow between nodes. The model optimises the generation and storage capacities attached to each node and optimises the transmission capacity between the nodes.

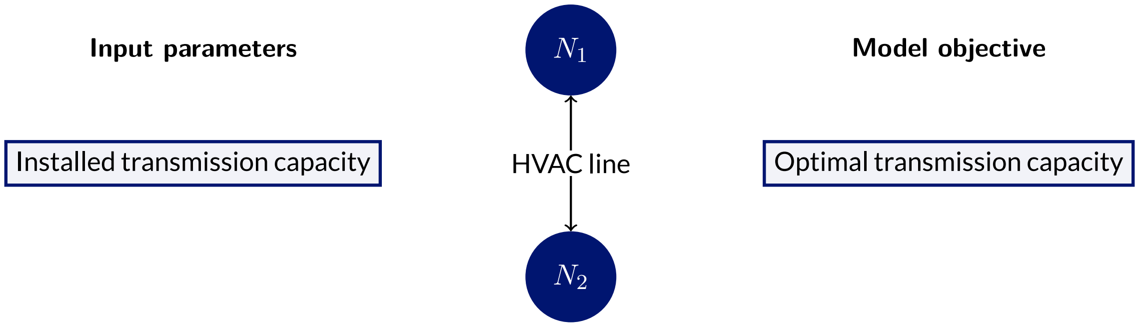

Figure 3.5: Two-node setup with transmission line and technology characteristics.

Objective

The objective of PyPSA is to minimise the total system cost of the electricity network, while satisfying two constraints: supply must meet demand and CO_2 emissions may not exceed a certain limit. This is done by optimally determining the investment and dispatch decisions for generation, storage, and transmission infrastructure over a predefined time horizon. In essence, PyPSA seeks the most cost-effective configuration of the energy system under given boundary conditions.

As shown in Equation 2 (PyPSA, n.d.-b), the objective function consists of both capital expenditures (CapEx) and operational expenditures (OpEx). Capital costs arise from investments in generation capacities ($\overline{g}_{n,s}$), storage capacities ($\overline{h}_{n,s}$), and transmission capacities (F_l). This is done by summing for all nodes n, all technologies s and all lines l. These costs are annualised over the lifetime of the technology. Operational costs include the variable costs of dispatching generation and storage technologies ($g_{n,s,t}$ and $h_{n,s,t}$), as well as startup and shutdown costs ($su_{n,s,t}$ and $sd_{n,s,t}$) where applicable. A time weighting factor (ω_t), with unit hours per year, is included such that the operational expenses are expressed in Euros per year.

$$\min \Bigg(\sum_{n,s} c_{n,s} \cdot \overline{g}_{n,s} + \sum_{n,s} c_{n,s} \cdot \overline{h}_{n,s} + \sum_{l} c_l \cdot F_l$$
$$+ \sum_t w_t \left[\sum_{n,s} o_{n,s,t} \cdot g_{n,s,t} + \sum_{n,s} o_{n,s,t} \cdot h_{n,s,t} \right] \quad (2)$$
$$+ \sum_t [su_{n,s,t} + sd_{n,s,t}] \Bigg)$$

- n: Node (location)
- s: Technology type (e.g. offshore wind, iron-air)
- l: HVAC transmission line
- t: Time step [h]
- $c_{n,s}, c_l$: Annualised CapEx [€/MW]
- $\overline{g}_{n,s}, \overline{h}_{n,s}$: Installed generator and storage capacities [MW]
- F_l: HVAC transmission line capacity [MW]
- w_t: Time weight [h/year]
- $o_{n,s,t}$: OpEx [€/MWh]
- $g_{n,s,t}, h_{n,s,t}$: Generation and storage dispatch [MW]
- $su_{n,s,t}, sd_{n,s,t}$: Startup/shutdown costs [€]

This formulation allows PyPSA to perform co-optimisation of generation, storage, and transmission investments and can therefore be used to answer how SDES and MDES technologies affect investments in transmission infrastructure.

3.3 Model Assumptions

A number of assumptions are made to obtain results within the given time frame. The implications of these assumptions are discussed in Chapter 6.2.

1. Spatial scope: the model covers the Dutch electricity grid, represented through a 55-node spatial resolution. Interconnections with neighbouring countries are excluded from this model due to time constraints.
2. Temporal scope: the simulation runs at an hourly resolution over the course of a single year using 2023 data, which is the most recent year for which full hourly demand and weather data are available.
3. Technological Scope: the study focuses exclusively on Battery Energy Storage Systems, differentiating between SDES and MDES systems. This technological focus is based on a gap in the existing literature and aligns with the research objective of assessing their potential in deferring grid expansion. Therefore, other storage technologies, such as hydrogen, pumped hydro, or thermal storage, are excluded from the core model. However, hydrogen storage is included in the sensitivity analysis due to its prominence in policy discussions. Besides, the model model has been scoped to the Transmission System Operator (TSO) level, since large-scale renewable energy sources are typically connected directly to the high-voltage grid, making TSO-level grid planning the more relevant under conditions of increased renewable penetration (see Chapter 1). Grid expansion on distribution level is neglected.
4. Energy System Boundaries: the model is electricity-only, meaning that it does not include sector coupling with heat, gas, or mobility sectors. As such, the impact of storage is assessed solely within the context of electricity supply and demand.
5. Weather conditions in future years are assumed to be the same as in 2023.

6. Future electricity demand is assumed to follow the current hourly load pattern, scaled by a uniform multiplier. This simplification was chosen because while projections for future electricity demand typically provide estimates in annual totals (in TWh/year), detailed hourly demand profiles are not readily available. To account for the expected increase in demand, the current hourly demand profile is scaled using a single multiplier.
7. The model assumes that the optimal energy mix is the most cost-effective one, neglecting other requirements such as security of supply.
8. The model does not incorporate social or policy dynamics. Decisions are assumed to be made based on cost-optimisation principles. Stakeholder behaviour, market structures, or regulatory constraints are neglected. This implies that we assume a flexible allocation of grid capacity where generators can dispatch power as long as capacity is available and are curtailed when it is not, in contrast to real-world systems that often rely on rigid contractual arrangements granting fixed grid access regardless of actual utilisation.
9. The model focuses exclusively on the electricity sector, neglecting sector coupling (e.g., with heating, industry, or transport).
10. Flexible technologies other than SDES and MDES (e.g., interconnection, demand-side response, or power-to-X solutions) are neglected and assumed to have negligible influence on grid expansion or storage needs.
11. Lithium-ion and iron-air batteries are assumed to represent the SDES and MDES categories, respectively, and their characteristics are assumed to be equal to current or near-future estimates.
12. Spatial constraints for installing new storage assets are not considered.
13. The modelling framework uses an ”overnight” optimisation approach, assuming all investments and system changes can be implemented at once, without considering iterative steps or investments over time.

3.4 Model Validation

The PyPSA-Eur model has been used without modifying its internal components. Therefore, the validation previously conducted by Hoersch et al. (2018) can largely be relied upon. The paper validates the model based on four key characteristics. First, it compares total circuit lengths with ENTSO-E statistics for all European countries, showing a mean absolute error for the 300 kV and 380 kV lines of 7% and 9%, respectively. Second, network topology is assessed by comparing PyPSA-Eur to other open German grid datasets, which revealed a high correlation when comparing the line volume across sources. Third, the assumptions regarding wind and solar generation expansion in Germany are validated by comparing them with values from existing literature, which fell within published ranges, accounting for differences in land use assumptions and exclusion zones. Lastly, a linear optimal power flow simulation was conducted for the European peak load hour, revealing some load shedding—an indication that the model was unable to meet demand in certain regions, despite the real-world system having done so. This highlights a mismatch between the model and reality. However, the paper reports no such issues for the Dutch grid, only for several other European countries; thus, this does not affect the accuracy of the results in this study.

This study utilises the PyPSA-Eur model but changes several input parameters, hence the contribution of this study lies in the selection of appropriate parameters that represent a realistic scenario for assessing the impact of SDES and MDES technologies on grid investment deferral in the Netherlands. The selection of these input parameters (as discussed in Chapter 3.5) introduces some uncertainty. Therefore, a sensitivity analysis is employed, as further elaborated in Chapter 4.4, which also includes a discussion on the effect of assumptions inherent to the PyPSA-Eur model. In addition to the sensitivity analysis, the results are validated by comparison with a similar study. This is done to validate the usage of the PyPSA-Eur model in general and improves validity by comparing the results to another modelling method.

The sensitivity analysis, which discusses the influence of input parameters, is determined by systematically varying input parameters conform a one-at-a-time (OAT) approach, where each parameter is individually adjusted to its minimum and maximum values as reported in the literature (see Figures C.1 to C.6). We consider a change in model results exceeding 10% compared to the benchmark scenario significant. This value has been chosen based on an educated guess. If results remain within a 10% margin, this indicates robustness, assuming all other parameters are held constant. The analysis does not consider simultaneous changes in multiple parameters but helps test the consistency of results across a possible range of inputs.

3.5 Input Parameters

3.5.1 Technology Input Parameters

Finding accurate values for the input parameters is of substantial importance, since these parameters determine the resulting output of the model. Parameter values for well-known technologies are included in the PyPSA library, but can be changed manually. Parameters that are likely to have a substantial influence on the results of this research (such as SDES, MDES technology parameters) are retrieved via desk research. First conceptual results are used to determine which parameters have a substantial influence and should therefore be gathered by thorough research. Data from several sources is compared and triangulated to find final values for the input parameters. Parameters that are considered to be less significant are copied from the PyPSA library, though their sources are validated and values are changed when deemed necessary. The sections below discuss individual technology parameters, while an overview is presented in Table 3.1.

Storage Technologies Identifying accurate parameter values for storage technologies is often challenging due to substantial discrepancies across sources. These variations may stem from applying the same technology in a different scale or context (e.g., residential versus grid-scale applications), from technological advancements such as improved efficiency through learning effects, or from differing system boundaries—such as whether components like grid connections and balance-of-plant elements are included. In this study, all relevant components, including the grid connection, are incorporated into the calculation of storage technology capital expenditures (CapEx). Next to that, we have assumed an average discharge time for lithium-ion of four hours.

Table 3.1: Complete list of relevant input parameters. Please see Confidential Appendix A for the full version of this table.

Technology	Parameter	Value	Unit	Remarks
Lithium-ion	Total project CapEx	300.15	€/kWh	See Fig. 2.3
Lithium-ion	RTE	84.55	%	See Fig. C.1
Lithium-ion	FOM	0.35	% per year	See Fig. C.1
Lithium-ion	Lifetime	12	years	See Fig. C.1
Lithium-ion	Discharge time	4	hours	
Iron-air	Total project CapEx	Confidential	€/kWh	See Fig. 2.4
Iron-air	RTE	Confidential	%	See Fig. C.2
Iron-air	FOM	Confidential	% per year	See Fig. C.2
Iron-air	Lifetime	Confidential	years	See Fig. C.2
Iron-air	Discharge time	Confidential	hours	
Solar	Total project CapEx	586.45	€/kW	See Fig. C.3
Solar	FOM	1.77	% per year	See Fig. C.3
Solar	Lifetime	31.6	years	See Fig. C.3
Onshore wind	Total project CapEx	1 380	€/kW	See Fig. C.4
Onshore wind	FOM	1.58	% per year	See Fig. C.4
Onshore wind	VOM	2.02	€/MWh	See Fig. C.4
Onshore wind	Lifetime	27.3	years	See Fig. C.4
Offshore wind	Total project CapEx	2 352	€/kW	See Fig. C.5.
Offshore wind	FOM	2.2	% per year	See Fig. C.5
Offshore wind	VOM	3.93	€/MWh	See Fig. C.5
Offshore wind	Lifetime	30	years	See Fig. C.5
Transmission grid expansion	Total project CapEx	5 884 803	€/Km	See Fig. C.6

Generator Technologies Capital costs for generator technologies vary considerably, driven by technology choice, installation configuration and local site conditions. In the Dutch section of the North Sea, shallow waters enable the use of cheaper fixed-bottom foundations, so the model adopts the Netherlands-specific cost benchmark from IRENA (2024) for offshore wind rather than the higher European average. These offshore wind CapEx include the costs for offshore substations and underwater export cables. Solar photovoltaic prices have dropped in recent years and two different types can be distinguished: the more expensive, yet more efficient single-axis tracker systems and fixed-tilt arrays (IRENA, 2024). Accordingly, a 2023 European average CapEx, including grid connection and representing a blend of fixed and tracker installations, is employed. Existing renewable plants are imported automatically from PyPSA-EUR, which draws on data from CBS (2023). The current coal and combined-cycle gas turbine generator plants are included into the model with their present capacity, yet any further expansion of these carbon-intensive generators is prohibited due to the model's emission constraints.

Grid Transmission Investments Estimating the capital costs of grid transmission investments is particularly complex due to the wide range of influencing factors and the limited availability of detailed commercial data. Public sources, such as annual reports from TSOs, often provide only aggregated figures, thus hiding the cost structure of individual projects. Besides, grid expansion projects can differ substantially in their characteristics: some projects involve building entirely new infrastructure, while others reuse existing pillars through rewiring or adding electricity lines, if the existing infrastructure permits. Location and the specific type of support structure further influence the investment requirements, making cost generalisation difficult across the grid. Figure C.6 shows an overview of the cost estimates of grid expansion projects. An average has been used as final value for the PyPSA model.

Uncertainty in Input Parameters Several of the final input parameter values used in this study carry a high degree of uncertainty due to significant differences between sources. These deviations may result from variations in technology scale, geographic context, system boundaries, or differing assumptions across studies. Averaging values across multiple sources improves the robustness of the input parameters to some extent, yet it does not fully resolve the inconsistencies. Consequently, parameters with substantial variation in sources have been included in the sensitivity analysis. The approach of this analysis is further described in Chapter 4.4.

3.5.2 Weather and Electricity Demand Data

Weather and electricity demand data are fetched from standard PyPSA-EUR sources (Hoersch et al., 2018). For weather data, PyPSA-EUR utilises two sources: the SARAH-3 solar surface radiation dataset by CM SAF (2023) and the ERA5 reanalysis dataset provided by ECMWF and Copernicus (2023). SARAH-3 provides the surface-irradiance that is converted into a capacity factor for the PV solar technology, while ERA5 supplies wind speeds for on- and offshore wind calculations and temperature data for dynamic line rating calculations of high voltage lines. These datasets form the basis for generating spatio-temporal cutouts that represent weather conditions specific to the Netherlands for the year 2023, aligning the simulation year with the most recent available electricity demand data.

Regarding electricity demand, PyPSA-EUR by default retrieves load profiles from OPSD (2020), which itself is based on ENTSO-E Transparency data. However, the most recent load profiles in the OPSD database are from the year 2020. In order to enhance the accuracy and relevance of the simulations, these demand profiles were replaced with data for the year 2023, manually obtained from ENTSO-E (n.d.). Since both the OPSD dataset and the newly used 2023 data come from the ENTSO-E Transparency platform, replacing this data ensures more up-to-date input while keeping the data source consistent. The total aggregated electricity demand can be observed in Figure 3.6. This total demand is allocated to the simulation nodes in proportion to their population and gross domestic product (Hoersch et al., 2018).

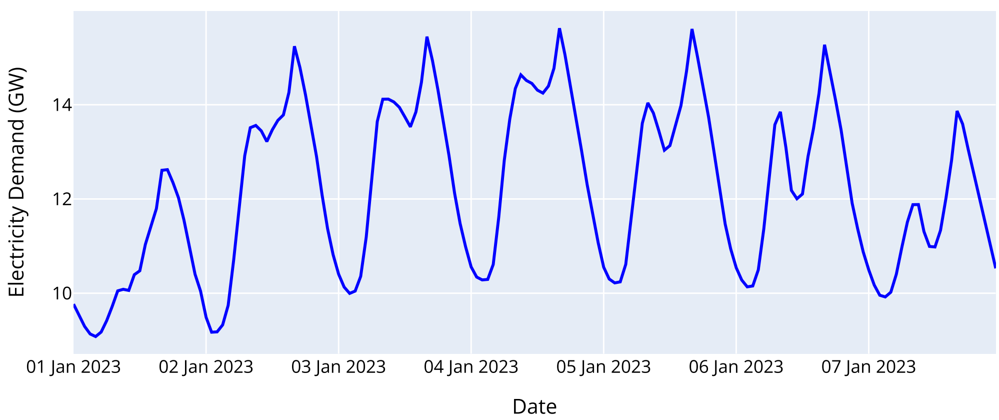

Figure 3.6: *Total electricity demand in the Netherlands for the first week of January 2023.*

3.5.3 Constraints

Limiting Emissions In line with the Dutch climate targets for 2030, the model imposes an annual emissions cap of 13 megatonnes CO_2 equivalent for the electricity sector (CBS, 2025). This constraint ensures that the electricity generation mix complies with national decarbonisation goals.

Space Constraints The availability of land is important, as placing utility-scale renewable energy farms in the centre of cities is not realistic. To account for this, the Corine Land Cover Database (European Environment Agency, 2019) is used by PyPSA-EUR, which categorises land in the Netherlands into various types such as Urban Fabric and Agricultural Areas. The available land can be limited by selecting which land categories in the Corine database are eligible for renewable energy farm development. In the simulation, the available land is limited to Corine's *"Agricultural Areas arable land"* and *"Agricultural Areas heterogeneous agricultural"* area categories, ensuring that renewable energy farms are not placed in urban, forested, or protected natural regions. The share of available land is visualised in Figure 3.7. Additionally, a utilisation factor of 10% is applied. This factor determines which ratio of the available land can be used for new generator farms, such as onshore wind farms. Although PyPSA defaults to 30%, a lower value is chosen. The choice to lower this factor from 30% to 10% is based upon first, conceptual modelling results that showed excessive installation of renewable energy farms in densely populated areas of the Netherlands, for example because of the presence of villages within Corine's *"agricultural zones"* categories. The value of 10% is based upon an educated guess. It is difficult to determine a definitive value, as it ultimately depends on political and societal decisions regarding how much agricultural land should be allocated for renewable energy development.

For offshore wind, the default constraints of PyPSA on sea depth and distance to shore are removed, as upcoming grid plans indicate future wind farms will be located further offshore. Lastly, land restrictions are not applied to battery installations, ensuring the model's optimisation of storage capacity is not influenced by spatial limitations. The feasibility of physically siting these batteries in the Netherlands is discussed later.

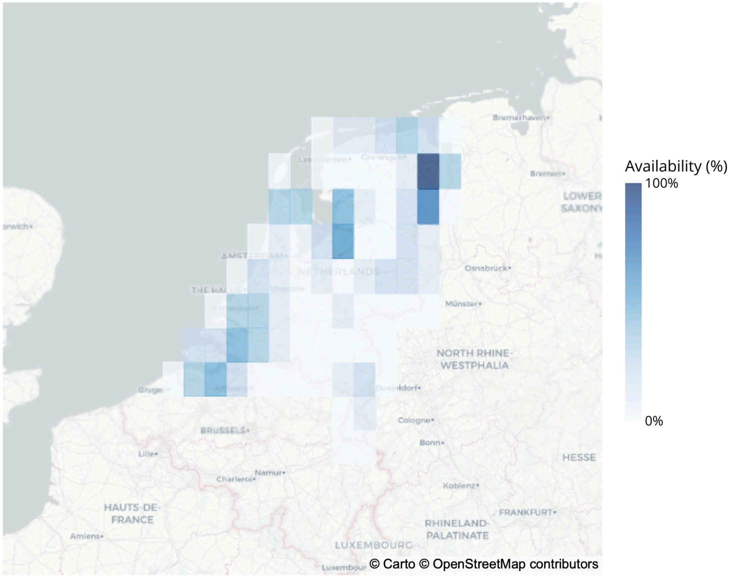

Figure 3.7: *Share of available land for the Onshore wind and Solar PV technologies*

3.6 Scenario Design

Two cases and four scenarios for each case are modelled to answer the research question. The cases differ from demand; one uses the current electricity demand while the other implements a 2040 forecast. This forecast assumes that the electricity demand is tripled with respect to the current demand (Netbeheer Nederland, 2023b). For each case, we run several scenarios by changing the availability of certain technologies. Table 3.2 shows the scenarios that will be modelled to give answer to the research question. The scenario without storage is used as reference point, as these results show the required grid transmission expansion without any storage technologies in the power system. The impact of adding SDES and MDES technologies upon transmission grid investments can be determined by comparing the results of the other three scenarios with the base-case.

Table 3.2: *The four scenarios that will modelled and used to answer the research question.*

Scenario	Technologies
No BESS	Transmission grid expansion only, no storage technologies.
SDES only	Transmission grid expansion + SDES systems (lithium-ion batteries)
MDES only	Transmission grid expansion + MDES systems (iron-air batteries)
All Technologies	Transmission grid expansion + SDES systems + MDES systems

3.7 Qualitative Interviews

To explore the implications of the quantitative findings for stakeholders and assess the challenges they may face in adopting SDES and MDES technologies, three semi-structured interviews were conducted. These interviews also serve to complement the PyPSA-based modelling results by incorporating perspectives from domain experts.

Participants were selected using judgement sampling, targeting individuals with the expertise in energy storage system integration. The selection was guided by the actor analysis in Chapter 2.4.3, focusing on high-power, high-interest stakeholders. Interviewees included two employees from TenneT with expertise in grid planning and one employee from the Dutch regulator ACM, offering both technical and regulatory perspectives.

The interviews were structured around two key themes:

1. **Differences Between Flexible Assets and Ownership Challenges**: this part assesses whether MDES (and battery energy storage more broadly) is considered a necessary solution compared to other flexibility options. This may raise any barriers or business implications regarding the MDES technology. Besides, it explores stakeholder views on ownership barriers, particularly the limitations TSOs face in owning batteries for congestion relief, and whether the incentive issues for market parties may limit adoption (as discussed in Chapter 2.4.2).
2. **Model Validation**: the second part validates the modelling approach and results, and seeks to understand divergences from reality. This is achieved by presenting a comparison between the results of this study (referred to as Model A) and those of a similar study used as a validation source (referred to as Model B). Interviewees are asked to comment on the sources of the differences and the realism of both models.

The semi-structured format enabled deeper exploration of emerging topics during the conversations. Interviews were conducted either online via Microsoft Teams or in person, depending on the preferences of the interviewee and interviewer, and each lasted approximately 60 minutes. With the interviewees' consent, conversations were recorded; otherwise, detailed notes were taken. Given the limited number of interviews, no formal coding procedure was applied. Instead, interviews were transcribed, summarised, and analysed by aggregating findings under the two thematic areas described above. Only aggregated results are reported to ensure participant privacy. The interview protocol can be observed in Appendix B.

4 Quantitative Modelling Results

This chapter dives into answering the second and third sub-research question via the PyPSA-eur model. A future state of the energy system is defined which consists of the most cost-effective generation and storage mix based on the modelling input parameters. The role of SDES and MDES is analysed by quantifying their ability to defer transmission grid investments in this future state of the energy system. The third sub-research question is addressed by presenting results related to the model's validity, including a sensitivity analysis and a comparison with findings from other studies.

4.1 Defining the Composition of the Future Energy System

The results of this and following subchapters have been split into 2023 and 2040 demand cases. Different sets of graphs are presented for each scenario to reflect findings relevant to each case; however, full visualisations for all scenarios are provided in Appendix C.

2023 Demand Case

Figure 4.1 shows the most cost-effective installed capacities of generator technologies. These represent the optimal capacities required to ensure that electricity supply meets the 2023 demand within the CO_2 constraint of 13 megatons. The installed capacities do not differ substantially across the various scenarios, indicating that the presence of different battery technologies does not significantly affect the generation mix for the 2023 demand scenario. This can be explained by the fact that coal and CCGT generators are still available to generate electricity in periods of low wind and little sun, decreasing the need for battery storage technologies. Yet, the usage of these conventional technologies is limited to a CO_2 emission of 13 megatons.

Offshore wind and solar PV capacities have been extended by $12.2\,GW$ and $9.9\,GW$, respectively, compared to the currently installed capacities in the Netherlands. Although these technologies still offer potential for further expansion, such investments are not considered cost-effective according to the model. No new CCGT or coal generators are built; the capacities shown are already present in the existing energy system. Similarly, the installed capacity of onshore wind farms is not increased, as the technology has reached its maximum capacity of $6.2\,GW$ due to land availability constraints.

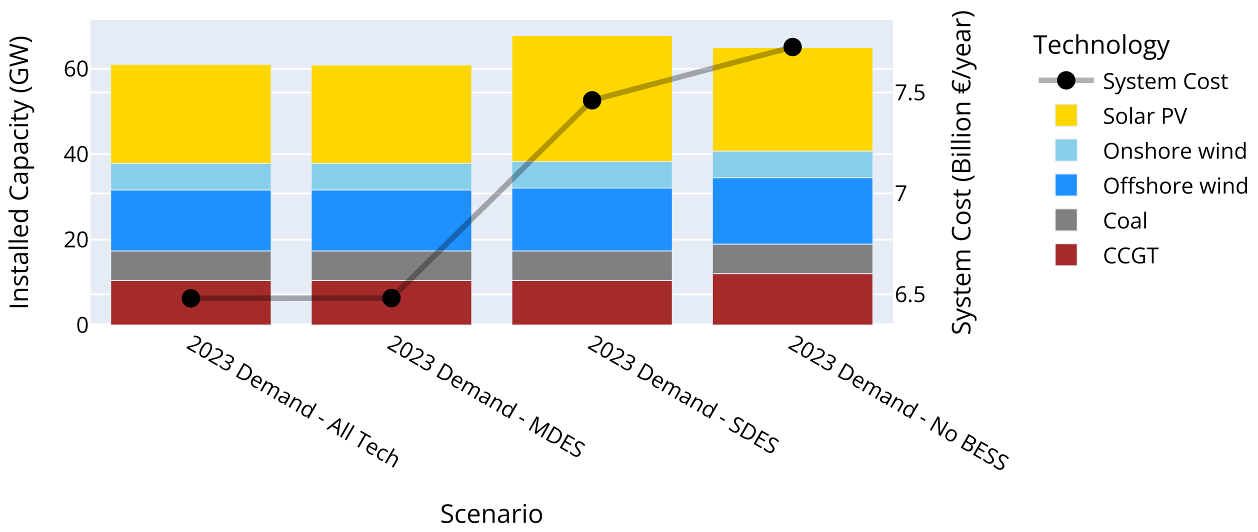

Figure 4.1: *Optimal generation capacities for 2023 demand scenarios*

The actual electricity generation from the installed generation capacities is strongly influenced by the availability and characteristics of storage technologies. As shown in Figure 4.2, generation technologies such as CCGT and coal are not always used at full capacity. The integration of battery systems significantly increases the generation from renewable sources, even though the installed capacity was similar across the different scenarios. Hence, the inclusion of storage reduces curtailment of renewable energy sources and allows to generate more electricity with the same installed capacity. This is also shown when comparing the electricity dispatch plots for the scenarios without and with energy storage, as can be seen in Figures 4.3 and 4.4, respectively. It can be observed that the scenario with MDES and SDES shows a reduced curtailment of renewable energy farms. Notably, MDES leads to a rise in the output from both onshore and offshore wind, which aligns with expectations discussed in Chapter 2.1; its discharge profile better matches the variability of wind production.

Interestingly, the addition of MDES results in a drop in CCGT usage, while coal generation increases slightly. CCGT plants have relatively high marginal costs but are efficient and able to respond quickly to demand fluctuations. Coal, on the other hand, typically has higher capital costs — though these are not considered in the model for already installed capacities — along with low marginal costs, lower efficiency, and a slower response time. In this context, batteries can take over the role of CCGT in providing fast-response flexibility, allowing coal to be dispatched more frequently as a source of cheap, albeit less flexible, electricity. Overall, the inclusion of storage technologies contributes to a reduction in total system costs. This is likely due to improved utilisation of installed renewable generation capacity, as the system can capture and dispatch more energy that would otherwise be curtailed — leading to a lower overall cost per kilowatt-hour. A breakdown of transmission-related expenses is provided later in the chapter.

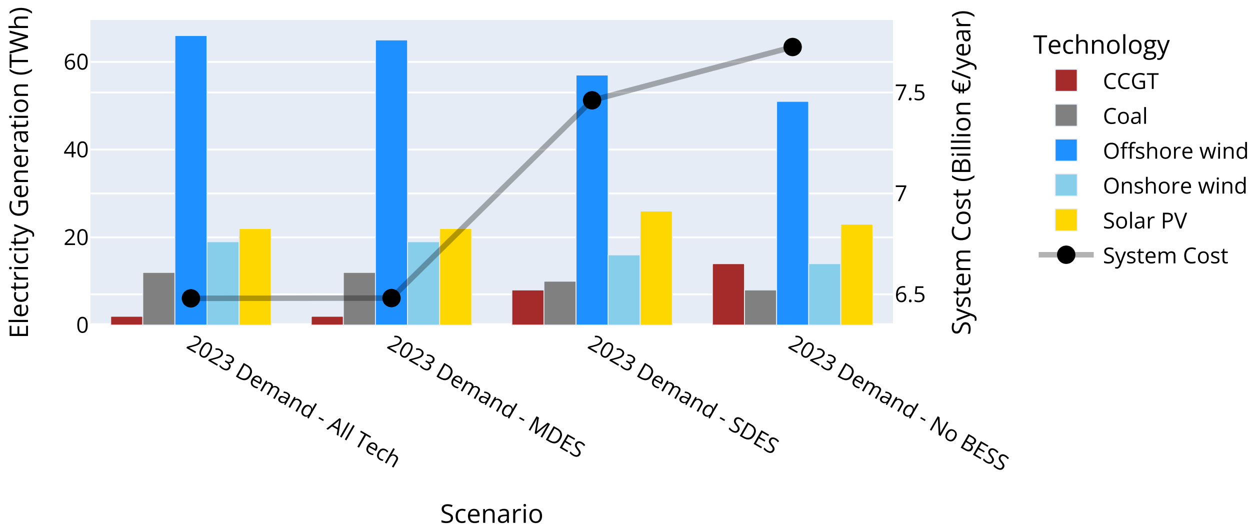

Figure 4.2: *Total electricity generation for 2023 demand scenarios.*

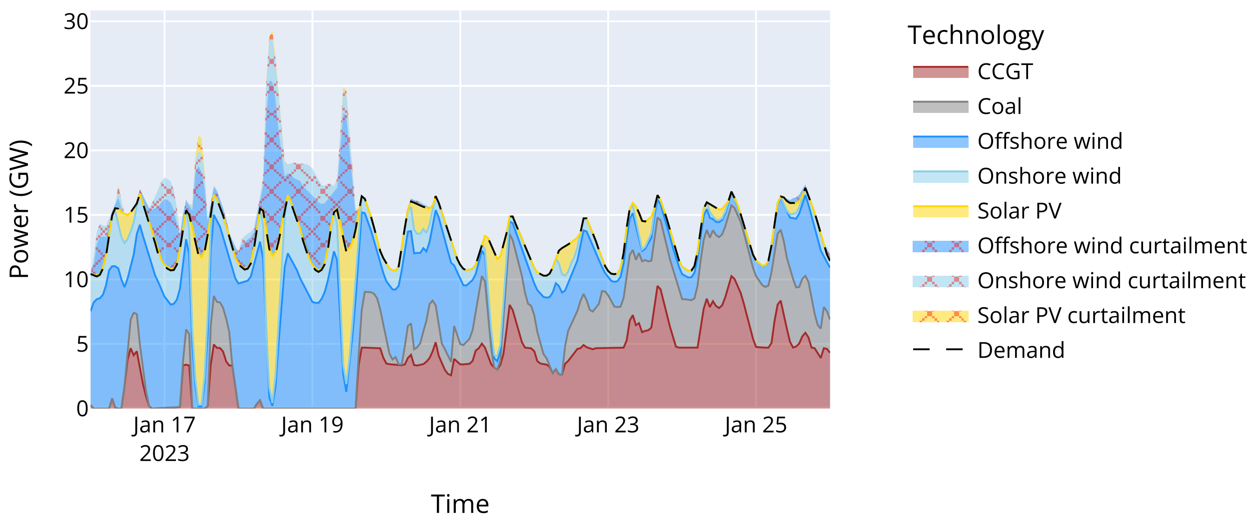

Figure 4.3: *Energy Dispatch for 7 days in January with above-average electricity demand, no battery storage scenario with 2023 demand.*

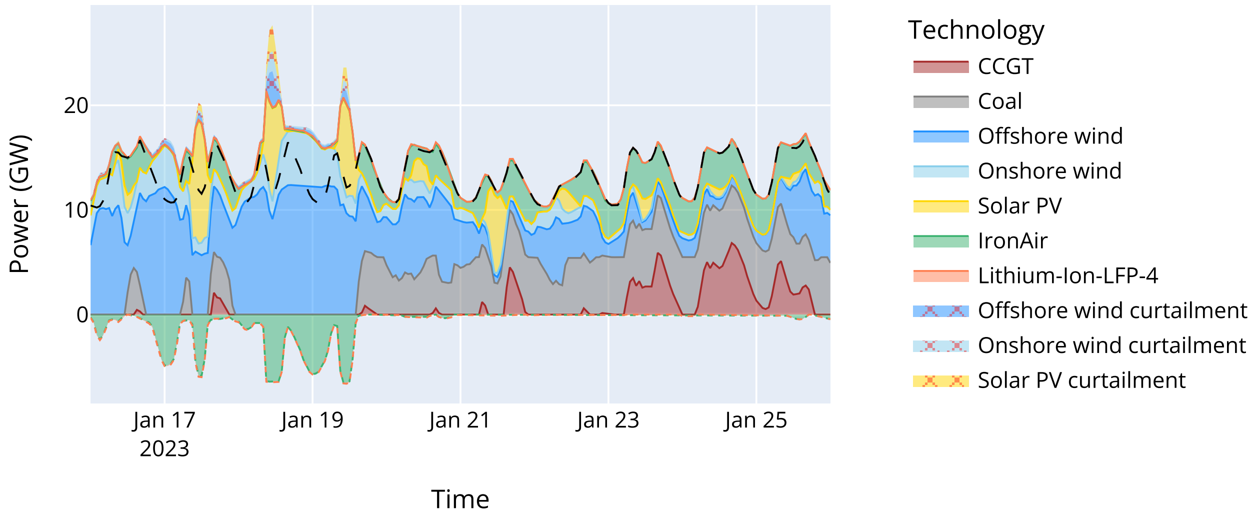

Figure 4.4: *Energy Dispatch for 7 days in January with above-average electricity demand, both MDES and SDES scenario with 2023 demand.*

Figure 4.5 presents the most cost-effective storage capacities selected by the model. These are expressed in terms of energy capacity (KWh), representing the total amount of energy each storage technology can hold. While this is a useful metric, it is important to note that for technologies such as SDES, the power at which they can charge and discharge (known as the power capacity, measured in KW) may be more relevant. A comparison based on power capacity would show a different distribution, as Iron-Air storage would be divided by 100, whereas lithium-ion would be divided only by 4. This is due to their difference in discharge time, which is the relation between battery capacity and power. Nevertheless, evaluating capacity is still insightful, as it reflects the total potential for energy balancing and storage over time.

The model shows that the installed power capacity is similar for the MDES-only and SDES-only scenarios — $6.98\ GW$ and $5.60\ GW$ respectively. Yet, due to their difference in discharge time the installed energy capacity is different. This could suggest that the system requires a certain minimum amount of available power to effectively integrate variable renewable generation. Dimensioning the battery such that it can deliver this power can result in over-dimensioning its capacity. This is especially a risk for the iron-air technology, as it requires 100 kWh of storage capacity to achieve 1 kW of dispatchable power due to its long discharge time characteristic. However, Figure 4.6 shows the state-of-charge (SoC) of the battery technologies and indicates that all installed capacity is actively used. This plot also shows the contrast between iron-air and lithium-ion technologies; iron-air exhibits longer discharge durations, resulting in slower and lower-frequency SoC fluctuations compared to the more responsive lithium-ion batteries.

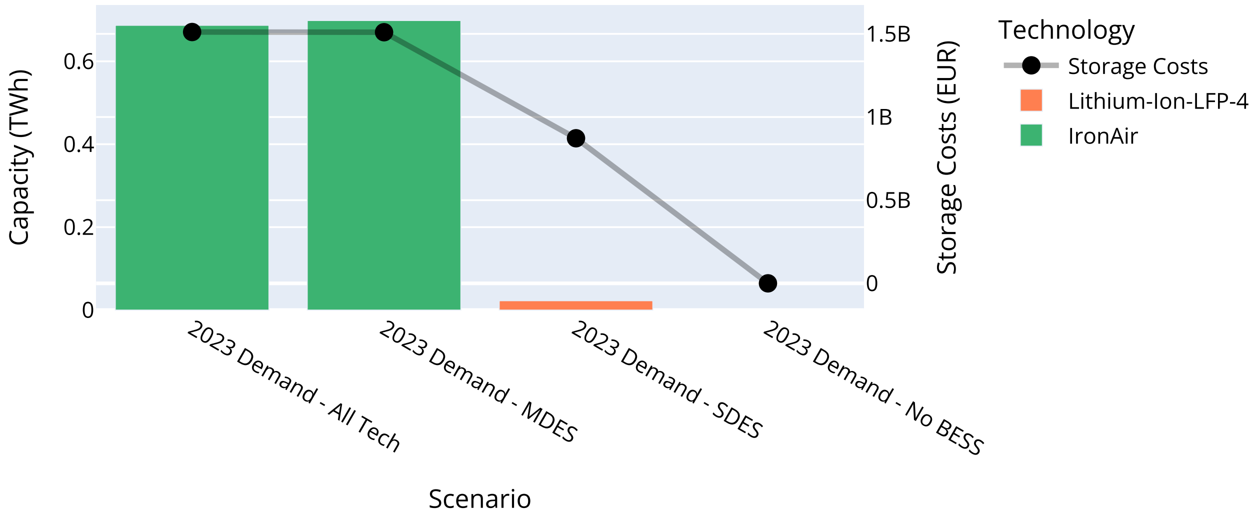

***Figure 4.5:** Optimal storage capacities for 2023 demand scenarios.*

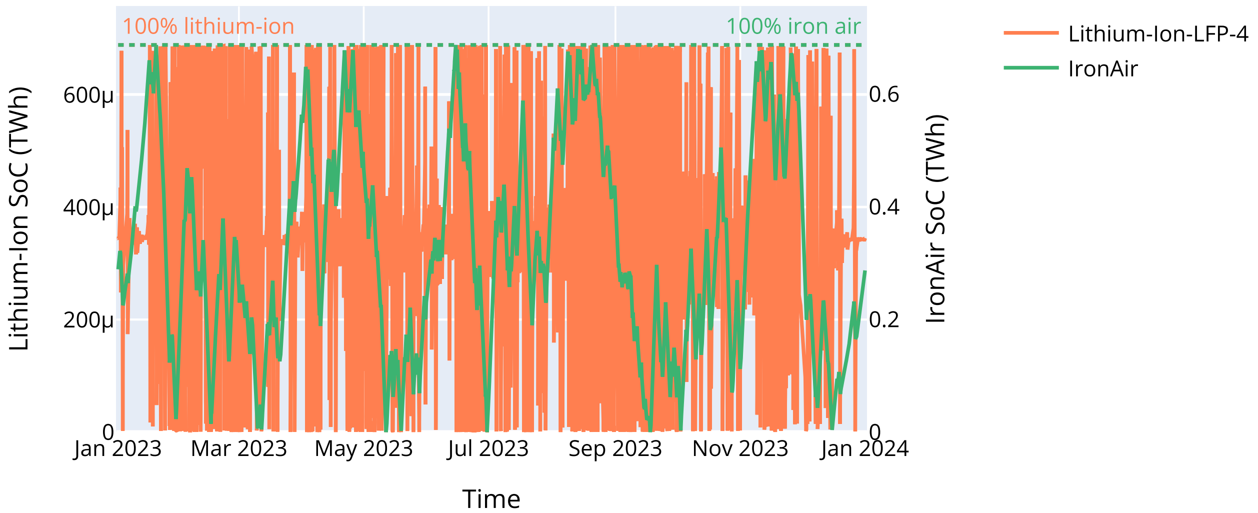

***Figure 4.6:** State of charge of batteries for a scenario with both SDES and MDES with 2023 demand*

2040 Demand Case

Figure 4.7 illustrates the installed generation capacities for the 2040 demand scenario, where electricity demand is tripled relative to 2023. Unlike the 2023 case, the scenario without any battery storage shows a substantial increase in installed capacity. This is due to the tripling of the baseload, which coal and CCGT are no longer able to supply due to CO_2 constraints. Meeting baseload demand with renewables alone requires excessive overbuilding and curtailment, as can be observed in Figure 4.8. The figure shows that there is no storage available to shift generation to periods of high demand or low supply. This drastically increases the generator capacity that is required, as they must provide the baseload demand in low wind and low sun conditions as well. When battery storage is introduced, the total installed generation capacity decreases significantly. This installed capacity does not differ substantially across the battery scenarios, indicating that both SDES and MDES storage can reduce the need for excessive generation capacity. However, the type of storage does influence the total system costs. Besides, these total system costs are lower in the scenario when all technologies are combined, indicating that the different technologies supplement each other.

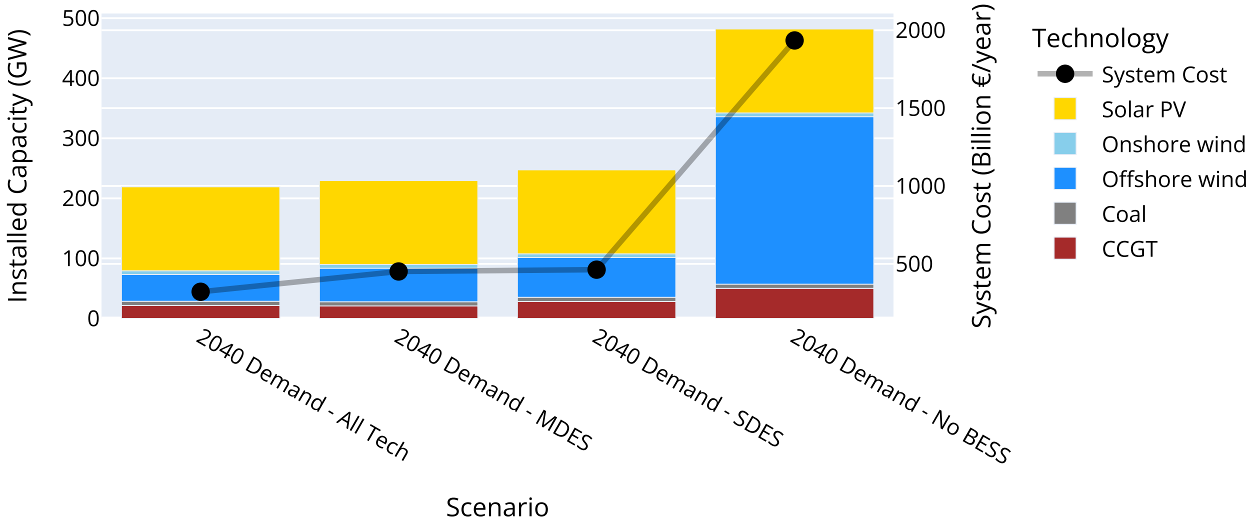

Figure 4.7: *Optimal generation capacities for 2040 demand scenarios*

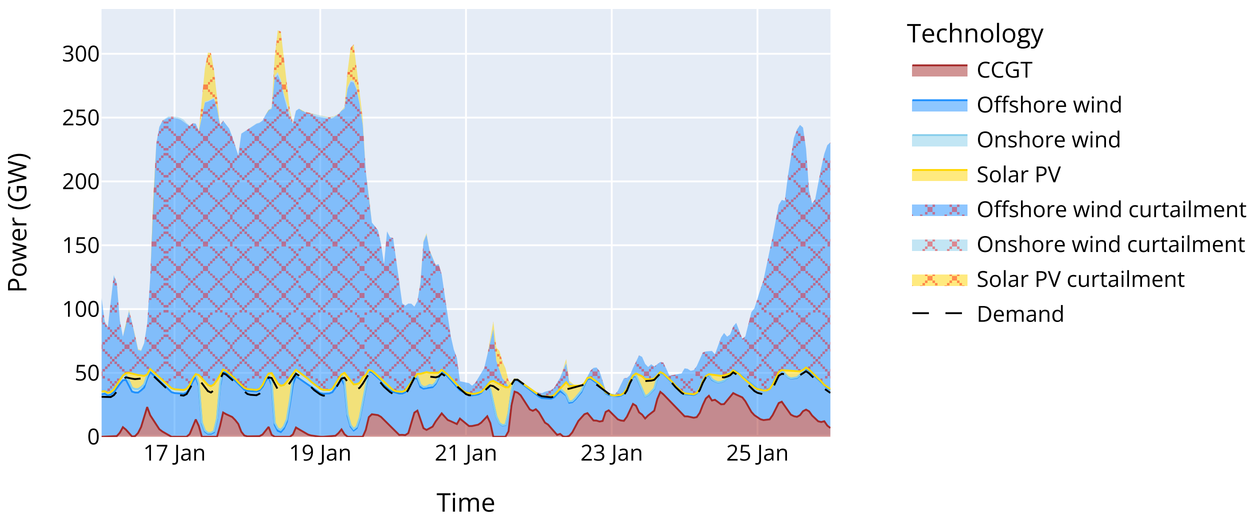

Figure 4.8: *Energy Dispatch for 7 days in January with above-average electricity demand, no battery storage scenario with 2040 demand.*

Figure 4.9 shows the power dispatch over time for an above-average demand period in the 2040 case that includes both SDES and MDES technologies. The dispatch pattern reveals that short-term, high-frequency solar peaks are primarily stored in lithium-ion batteries, while iron-air batteries are used to store and discharge baseload energy. This supports the idea that SDES and MDES complement each other due to their difference in discharge time.

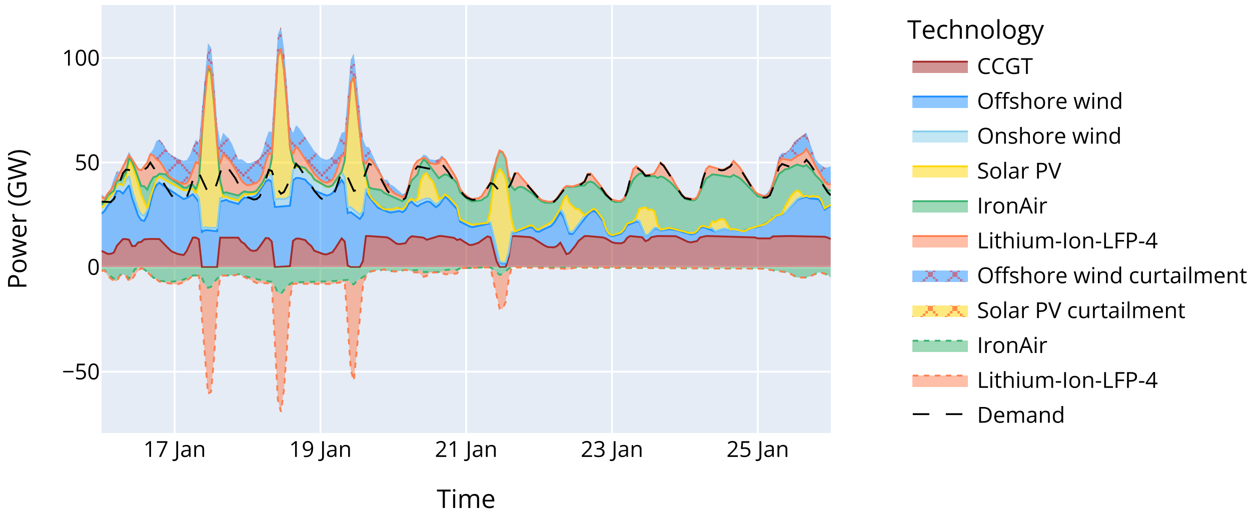

Figure 4.9: *Energy Dispatch for 7 days in January with above-average electricity demand, both MDES and SDES scenario with 2040 demand. Negative power indicates charging batteries.*

Figure 4.10 shows the state of charge over time for the scenario with both storage technologies and highlights the seasonal role of iron-air batteries. They charge gradually during the summer months and discharge over the winter, acting as long-duration or seasonal storage. This is different from the 2023 demand case, where the iron-air technology cycled roughly five times per year (see Figure C.11). The difference can likely be explained by the increased dependence on storage in 2040, as fossil-based generators such as CCGT and coal cannot provide the full winter baseload due to CO_2 limitations combined with higher overall demand.

Figure 4.10 also shows that when a combination of both SDES and MDES technologies is deployed, the batteries cycle through their full energy capacity range. This is not the case in scenarios where only one storage technology is deployed (as shown in the Appendix in Figures C.26 to C.31). When both technologies are combined, the state of charge better matches the installed battery capacity, indicating more effective utilisation and reducing the risk of over-dimensioning.

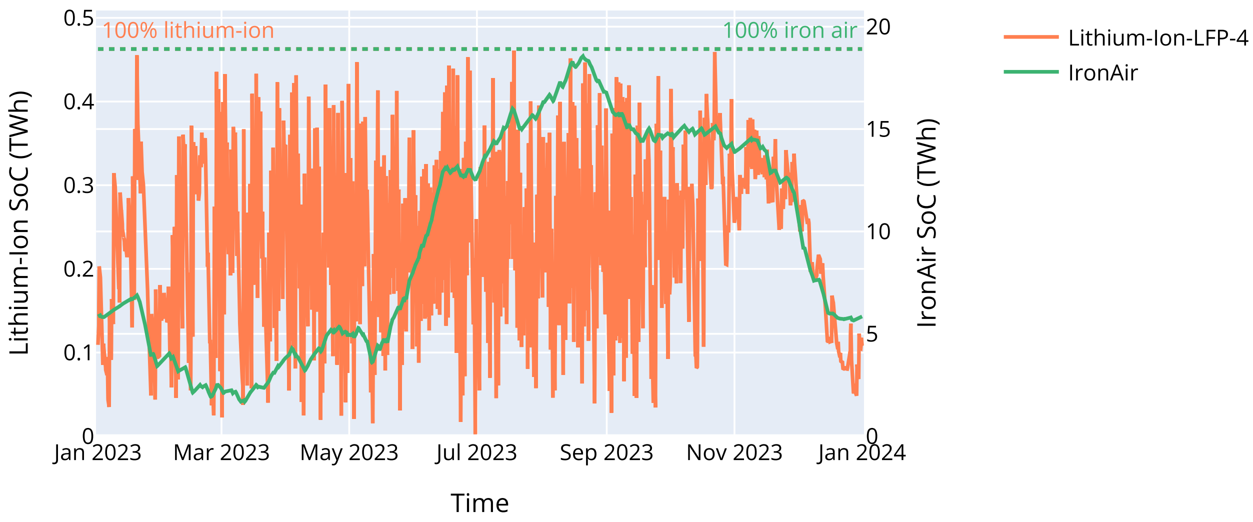

Figure 4.10: *State of charge (SoC) of batteries for a scenario with both SDES and MDES with 2040 demand.*

4.2 Determining the Deferral in Grid Investments

2023 Demand Case

The results suggest that, under the modelling assumptions, the existing transmission grid is capable of accommodating the 2023 electricity demand via renewable energy integration while remaining within the CO_2 emissions cap of 13 megatons. As shown in Figure 4.11, there is a small increase in average line loading when battery storage technologies are included in the energy mix, indicating more efficient use of existing infrastructure. However, even without BESS the model shows that transmission grid expansion is not cost-effective and hence not needed to meet 2023 demand via integration of renewable energy sources (see Table 4.1).

Important to note is the difference in grid capacity allocation between the PyPSA modelling approach and the real-world scenario. Currently, actors with a grid connection are entitled to draw their full contracted capacity at any time, even if they seldom do so, leading to a perceived grid saturation. PyPSA, however, models only the capacity that is actively used, effectively simulating an ideal system in which grid access is dynamically allocated according to actual need. This theoretical optimum shows what the grid is capable of, if handled in a flexible way. This difference is further explored in Chapter 4.4.

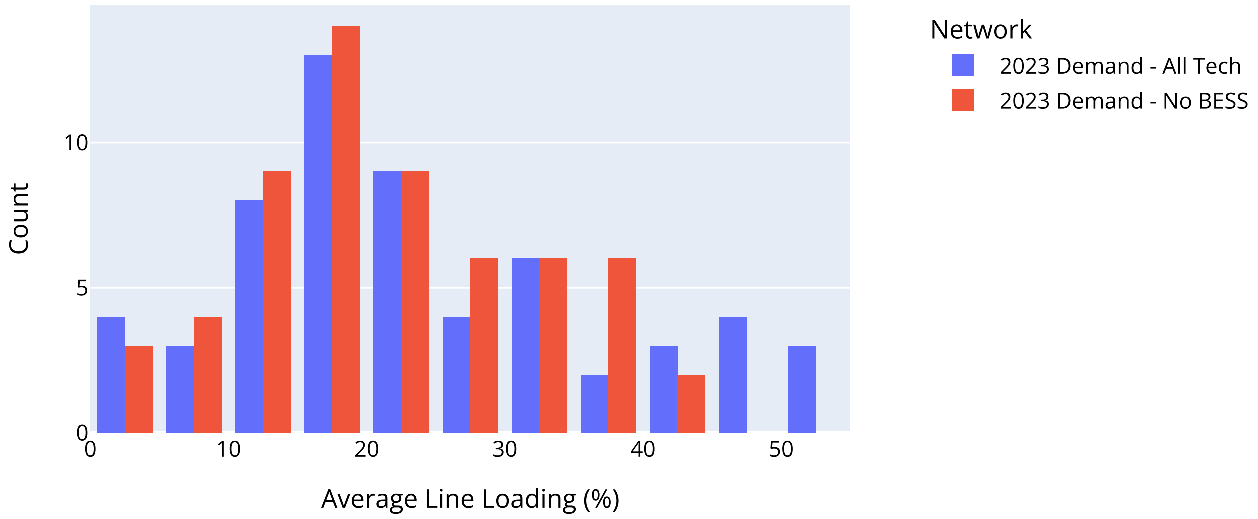

Figure 4.11: *Average HVAC line loading for two scenarios with 2023 demand. The loading of a line is averaged over time, the count represents the number of lines with that loading.*

Table 4.1: *Transmission Grid Deferral for the 2023 demand case*

Scenario	Battery Capacity [TWh]	Added Grid Capacity [GW]	Grid Investment [Billion €]
No BESS	0	0.0	0.0
SDES only	0.02	0.0	0.0
MDES only	0.70	0.0	0.0
Both SDES and MDES	0.69	0.0	0.0

2040 Demand Case

In the 2040 case, Figure 4.12 shows an increased average line loading when compared to 2023 scenarios, due to the greater volumes of generation and demand that must be transported. Within 2040, the scenario with battery storage again exhibits a higher average line loading than the one without BESS, signalling more effective utilisation of the network when storage is available. This occurs because BESS technologies enable stored energy to be dispatched during periods of lower line loading, thereby raising the average loading.

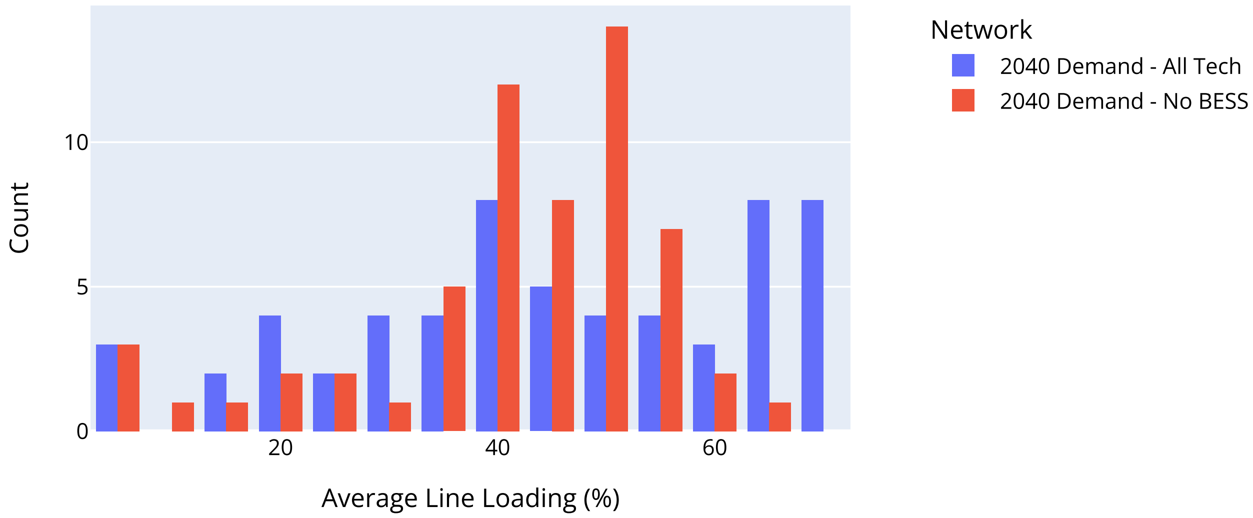

Figure 4.12: *Average HVAC line loading for two scenarios with 2040 demand.*

Table 4.2 shows that the model deems grid expansion to be cost-effective: without battery storage, $86.2GW$ of new capacity must be installed, whereas with both SDES and MDES only $11.8GW$ of additional grid capacity is required. It is important to emphasise that the model's cost-minimisation objective results in a tendency to fully utilise the capacity of the transmission lines. This effect is illustrated in Figure 4.13, which presents the total number of congested hours across the transmission network. The figure reveals that the inclusion of BESS increases congestion, which may be undesirable from a reliability standpoint. However, it also implies a more efficient use of the available transmission capacity, while ensuring that supply meets demand in the meantime. Lastly, Figure 4.14 displays the specific locations where grid expansion is required. The figure indicates that the cable linking offshore wind to onshore demand requires by far the greatest reinforcement ($6GW$). A few additional lines in the northern region also call for modest upgrades, but overall only a limited number of transmission lines need expansion. This is different for the scenario without any battery storage, as can be seen in Figure C.41. It shows that the grid requires much more expansion, but also at different locations.

Table 4.2: *Transmission Grid Deferral for the 2040 demand case*

Scenario	Battery Capacity [TWh]	Added Grid Capacity [GW]	Grid Investment [billion €]
No BESS	0	86.2	1849.5
SDES only	1.89	18.8	357.3
MDES only	20.55	19.9	378.4
Both SDES and MDES	19.40	11.8	236.1

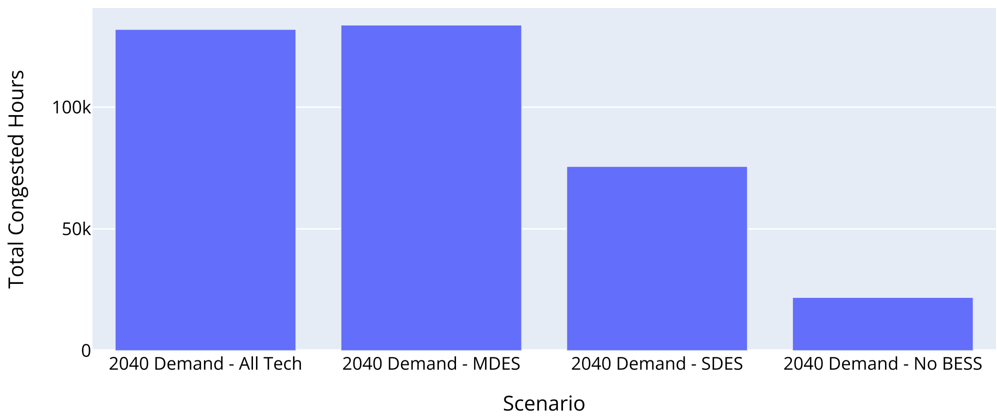

Figure 4.13: *Sum of congested hours for all HVAC lines (in total: 59) across various scenarios.*

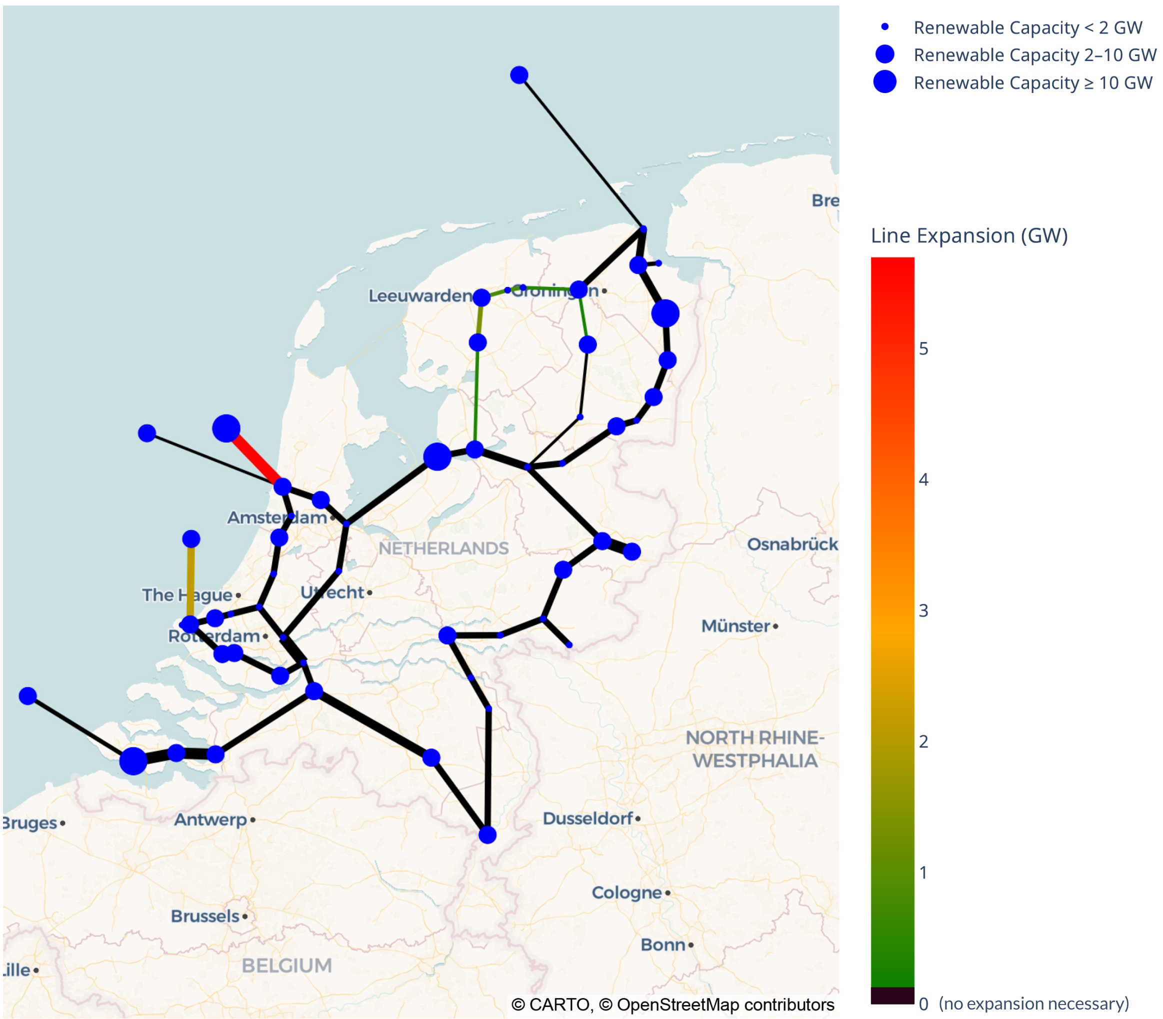

Figure 4.14: *Expansion of TSO network for a scenario with both SDES and MDES storage. The colour of the line represents the required expansion. The width of the line represents the optimal line capacity.*

4.3 Comparing the impact of SDES and MDES Technologies

This section compares the role and performance of SDES and MDES technologies across both the 2023 and 2040 demand scenarios, based on their ability to defer grid expansion and reduce total system costs.

In the 2023 demand case, the inclusion of MDES results in a noticeable increase in wind energy output. This outcome aligns with expectations outlined in Chapter 2.1, as the discharge profile of MDES better matches the variability of wind production. Despite similar installed generation capacities across all scenarios, MDES allows for more effective utilisation of both onshore and offshore wind, improving the overall efficiency of renewable integration without requiring additional generation infrastructure.

In the 2040 scenario, where electricity demand triples compared to 2023, both SDES and MDES individually contribute to significant deferral of transmission grid investments. When deployed separately, each technology reduces the required transmission grid expansion from $86.2\,GW$ in the no-storage scenario to $18.8\,GW$ for SDES only and $19.9\,GW$ for MDES only. However, the most cost-effective system outcome is achieved when the two technologies are deployed together. In this combined scenario, total annual system costs are reduced from €451 billion (MDES-only case) to €320 billion, underscoring the economic benefits of integrating both storage types. Additionally, the required grid expansion falls further to $11.8\,GW$, highlighting the complementary nature of these technologies in maximising investment deferral while enhancing system performance.

The dispatch patterns further illustrate the distinct roles played by SDES and MDES. Lithium-ion batteries, representing SDES, primarily manage short-term, high-frequency fluctuations—such as solar generation peaks. In contrast, iron-air batteries, representing MDES, are used to store and discharge energy aligned with baseload demand. This functional differentiation allows each technology to operate in its optimal range. Due to their large energy capacity and long discharge duration, iron-air batteries gradually charge during summer and discharge during winter, effectively functioning as seasonal storage. Attempting long-term energy storage with lithium-ion would require substantial over-dimensioning of power capacity, since its discharge time is not suited to long-duration use. Conversely, using iron-air for short-duration balancing would result in an oversized energy capacity. Therefore, a mixed deployment avoids such inefficiencies and improves the utilisation of installed storage assets.

These findings highlight the complementary nature of SDES and MDES technologies in creating a cost-efficient and flexible energy system. Their distinct technical characteristics—particularly with regard to their discharge time—enable them to serve different functions. Lithium-ion batteries (SDES) are well-suited for managing fast, high-frequency fluctuations in electricity supply and demand due to their rapid response and high power output, but they are less economical for long-duration storage. In contrast, iron-air batteries (MDES) offer a cost-effective solution for storing large volumes of energy over extended periods, making them ideal for addressing multi-day or seasonal mismatches in renewable generation, although their low power output limits their usefulness for short-term balancing. By deploying both technologies together, the system can efficiently reduce curtailment, improve renewable integration, displace fossil-based generators such as CCGT and coal, and defer transmission grid expansions. This reduces the overall system costs under these scenarios with high renewable penetrations.

4.4 Testing Model Validity

The model validity is addressed by comparing the results with findings from other studies and performing a sensitivity analysis. This chapter starts with the results of the comparison, for which the sector-coupled study from Netbeheer Nederland (2023c) is used. Afterwards, the sensitivity analysis is presented. This is done by presenting the impact of changes in Policy Levers, followed by the impact of changes in External Drivers (this is conform the XLRM framework discussed in Chapter 3.1). This chapter closes with a definition of input parameters ranges for which the model results are robust. This supports answering the third sub-question: *How do variations in model input parameters and modelling assumptions influence the outcomes of energy storage scenarios for deferring transmission grid investments?*

4.4.1 Comparison with Sector-Coupled Study

We validate our modelling results by comparing them with the future scenarios developed by Netbeheer Nederland (2023c). These scenarios are particularly relevant as they are based on the same target of a 55% reduction in CO_2 emissions by 2030. Yet, the scenarios use a different electricity demand, hence the results of this study have been scaled linearly such that the demand of the two studies matches. The validation scenario is produced by a working group operating under the umbrella of Netbeheer Nederland, with input from a broad range of external stakeholders. Among the three scenarios discussed, the *KlimaatAmbitie* (Climate Ambition) scenario serves as the reference point for our validation step, since the others explore alternative pathways with greater emphasis on either electrification or the use of sustainable gases. Netbeheer Nederland has performed an assessment to ensure the realism and feasibility of the scenarios across both supply and demand sectors, which makes them a reliable benchmark for validating our own outcomes.

Table 4.3 presents a comparison between the results of this study and those of Netbeheer Nederland. The generation technology capacities are broadly similar. In the 2023 case, this study uses less solar and onshore wind compared to the validation source, but compensates with more offshore wind. For 2040, the total installed generation capacity is higher in this study than in the Netbeheer scenario. However, the most notable differences lie in the deployment of flexible assets. In 2023, our study assumes a lower total capacity for these assets, whereas in 2040, the capacity is significantly higher than in the validation source. Finally, there is a clear divergence in the assumed TSO grid expansion capacities. In 2023, grid expansions were considered not cost-effective in our model, resulting in a reliance on alternatives such as batteries to balance supply and demand. For 2040, our modelling results indicate a grid expansion of $8.4\,GW$, compared to $64.8\,GW$ in the Netbeheer scenario.

Table 4.3: Validation of the 2023 and 2040 case by comparing the electricity demand, generation, flexible Assets, and grid expansion to the KlimaatAmbitie scenario from Netbeheer Nederland (2023a, 2023c). Results from this study were scaled such that the demand equals the validation demand.

		2023 case			2040 case		
	Unit	**This study**	**This study, scaled**	**Validation**	**This study**	**This study, scaled**	**Validation**
Year		2023	–	2025	2040	-	2035
Demand							
Electricity	TWh	109.2	136	136	327.6	234	234
Generation							
Onshore wind	GW	6.2	7.7	7.3	6.2	4.4	10.6
Offshore wind	GW	14.2	17.7	6.1	44.6	31.9	30.5
Solar	GW	23.2	28.9	38.7	139.8	99.9	75.9
Nuclear	GW	0.0	0.0	0.5	0.0	0.0	0.5
Coal	GW	6.9	8.6	4.0	6.9	4.9	0.0
CCGT	GW	10.4	13.0	17.5	21.7	15.5	12.3
Total generation	**GW**	**60.9**	**75.8**	**74.1**	**219.2**	**156.6**	**129.8**
Flexible assets							
Batteries	GW	7.0	8.7	2.7	304.8	217.7	22.7
Interconnection	GW	–	–	9.2	–	–	12.8
Demand Side Response	GW	–	–	0.8	–	–	2.0
Power-to-heat	GW	–	–	1.5	–	–	5.3
Power-to-gas	GW	–	–	0.5	–	–	4.0
Total flexible assets	**GW**	**7.0**	**8.7**	**14.7**	**304.8**	**217.7**	**46.8**
Transmission grid							
HV grid	GW	0.0	0.0	0.0	4.0	2.8	31.3
Interconnection grid	GW	-	-	3.4	–	–	7.0
Grid at sea	GW	0.0	0.0	5.2	7.8	5.6	26.5
Total TSO expansion	**GW**	**0.0**	**0.0**	**8.5**	**11.8**	**8.4**	**64.8**

The differences between the Netbeheer scenarios and the results of this study can be largely explained by differences in system scope. While the Netbeheer scenarios focus on a sector coupled model of the total energy system — integrating electricity, heat, transport, and industry — this study concentrates solely on the electricity sector. As a result, the Netbeheer model has access to a broader range of flexibility mechanisms. For instance, excess electricity in their scenarios can be exported or absorbed through industrial Demand Side Response (DSR), where factories scale up operations when electricity supply is abundant. More than half of the surplus electricity in their 2035 scenario is handled via DSR or export, with only 15% being stored in batteries (see Table 4.4).

Table 4.4: The usage of flexible assets in the 2035 scenario from Netbeheer Nederland (2023a).

Category	Electricity converted	Unit	% of total converted electricity
Export	38.3	TWh	34.9%
Demand Side Response	21.1	TWh	19.2%
Battery storage	17.0	TWh	15.4%
Conversion to hydrogen	14.5	TWh	13.2%
Conversion to heat for industry	11.6	TWh	10.6%
Losses	7.3	TWh	6.6%

Netbeheer thus leans heavily on increasing demand or exporting electricity, which in turn requires substantial transmission capacity. This likely explains their much higher grid expansion estimates. Their modelling approach prioritises grid extensions over battery installations. In contrast, this study assumes fixed demand and does not account for import or export of electricity, which limits flexibility options and places more pressure on internal balancing mechanisms such as batteries.

When flexibility options are reduced, our modelling outcomes begin to align more closely with existing projections. Specifically, in the 2040 scenario without battery storage, we calculate a required TSO expansion capacity of $86.2\,GW$. This figure is in the same range as the $64\,GW$ projected by Netbeheer. The convergence of these results suggests that the inclusion or exclusion of flexible assets, such as battery storage, has a significant impact on required grid infrastructure. This points to a potential policy decision: increasing flexibility in the energy system may substantially reduce the need for transmission grid expansion. Our results depend heavily on the deployment of batteries as flexible assets, whereas Netbeheer places greater emphasis on expanding grid capacity to meet future demands while using other flexible assets.

While DSR may seem like a promising option, it likely involves significant changes to industrial processes. This would require these actors to operate more flexibly —something that, as discussed in Chapter 2.4.2, faces several barriers. Similarly, although import and export can help stabilise the grid, relying on neighbouring countries also transitioning to renewables introduces uncertainty due to increased intermittency and the risk of overlapping *Dunkelflaute* periods. Besides, the transport of this electricity to in- and outside of the Netherlands also requires transmission capacity.

Another key difference lies in how transmission grid expansion is treated. The PyPSA model used in this study does not consider long-term reliability planning. It optimises for cost in a single scenario, leading to minimal grid expansion—just enough to meet demand efficiently within the scenario's constraints. While this may result in lower investment costs, it may not reflect the grid operator's perspective, which must also account for future resilience and system flexibility.

The distinction between the capacity allocation of PyPSA and current grid practices can explain a difference in the results as well. In reality, grid users are entitled to access their full contracted capacity at any given time, regardless of actual usage patterns. This static allocation contributes to grid congestion and inefficiencies. In contrast, PyPSA allocates capacity dynamically based on real-time utilisation, effectively modelling a more flexible and efficient system. Although this may appear overly optimistic, it aligns with recent developments in Dutch grid policy. The introduction of time-bound transmission rights (TDTR) marks a shift towards more flexible grid usage in practice (TenneT, 2025). These new contracts, enable businesses to secure transport rights for a fixed number of hours per year, with TenneT retaining the ability to curtail access during peak moments. The TDTR initiative has already revealed $9\ GW$ of grid capacity that would otherwise be unused. This number is similar to the $8.5\ GW$ required transmission expansion modelled by Netbeheer Nederland for the 2025 case, and hence these expansion investments may be unnecessary due this new regulation. This policy shift suggests that grid operators are beginning to embrace principles similar to those modelled in PyPSA, potentially narrowing the gap between theoretical optimal, flexible usage of the grid and the actual real-world scenario.

4.4.2 Sensitivity Analysis of Policy Levers

This chapter discusses the effect of changes in the characteristics of lithium-ion and iron-air technology, and analyses the impact of the addition of hydrogen cavern storage as MDES technology. The values that are tested in this sensitivity analysis and a naming clarification of the scenarios is given in the first five columns of Table 4.8. The 2040 case is used as benchmark scenario, as no grid expansion was modelled in the 2023 case, which limits its suitability.

The effect of changes in iron-air parameters Table 4.5 shows that changes in the technology parameters of the iron-air battery do not result in a substantial difference in required grid investments nor in a difference in the installed capacity of the iron-air battery. However, a decrease in the round-trip efficiency of the iron-air battery does lead to a compensatory increase in the optimal installed capacity of lithium-ion batteries. This indicates a substitution effect: as the iron-air battery becomes less efficient, the system shifts towards technologies that can deliver flexible energy more efficiently. However, the installed capacity of iron-air itself is only marginally affected, suggesting its role as long-duration storage remains important despite reduced efficiency.

Table 4.5: *Sensitivity analysis summary for iron-air parameters. Highlighted values indicate deviations of more than 10% from the benchmark scenario.*

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Costs max	17.75	0.48	11.84	334.84
Costs min	19.53	0.45	11.71	312.36
FOM max	18.72	0.47	11.78	323.42
FOM min	19.01	0.46	11.74	319.59
RTE max	19.40	0.41	10.99	309.47
RTE min	18.48	0.54	12.52	336.24
lt max	19.12	0.46	11.72	318.47
lt min	18.67	0.47	11.78	324.37

The effect of changes in lithium-ion parameters The required grid investment and installed capacity of the iron-air battery is also not significantly affected by changes in the technology parameters of lithium-ion batteries. However, lower costs and longer lifetimes of lithium-ion batteries result in higher optimal installed capacities of this technology (see Table 4.6). Interestingly, this change does not substantially influence the deployment of iron-air batteries, which points to a functional separation: lithium-ion batteries are primarily used for short-term balancing, while iron-air is used for substituting baseload from fossil generation.

Table 4.6: Sensitivity analysis summary for lithium-ion parameters. Highlighted values indicate deviations of more than 10% from the benchmark scenario.

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Costs max	19.05	0.43	11.85	324.12
Costs min	18.79	0.51	11.62	317.82
FOM max	19.02	0.43	11.83	323.84
FOM min	18.89	0.47	11.75	320.76
RTE max	18.85	0.47	11.46	316.87
RTE min	18.98	0.45	12.09	325.42
lt max	18.81	0.51	11.64	318.06
lt min	19.01	0.44	11.82	323.19

The effect of hydrogen cavern storage integration The inclusion of hydrogen cavern storage, assumed to be available across the system, shows a clear impact on battery storage capacities (Table C.5). Hydrogen seems to take the role of seasonal storage and reduces reliance on iron-air batteries. However, grid investment requirements remain unchanged. It is important to note that this scenario does not yet account for spatial constraints, such as the availability of caverns only in the northern regions of the Netherlands. Therefore, the impact of hydrogen here may be overstated, and should be interpreted as an upper-bound scenario.

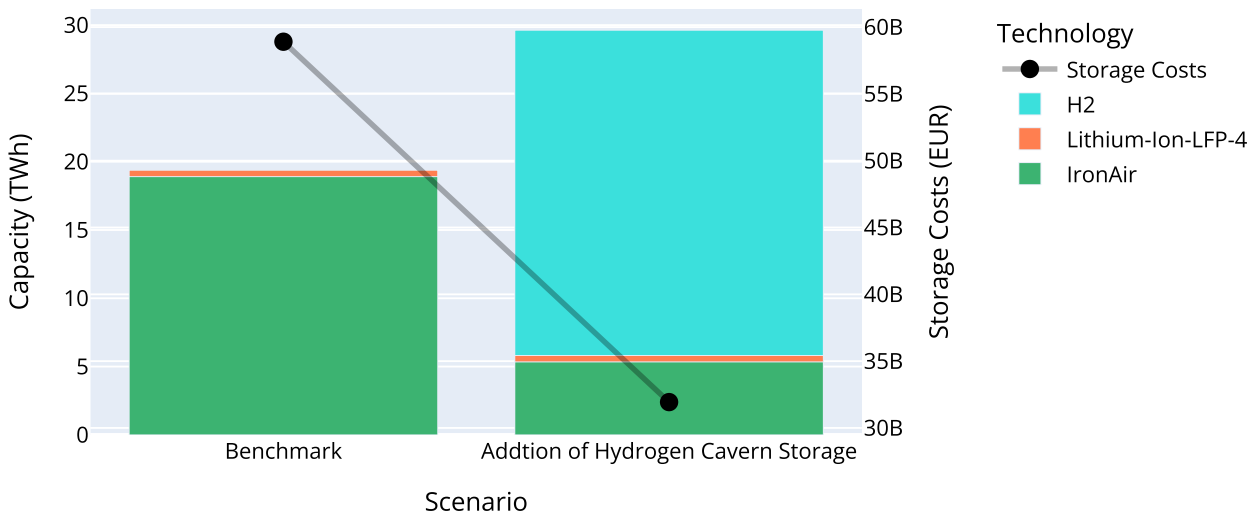

Figure 4.15: The influence of the addition of hydrogen cavern storage on storage capacity and costs.

4.4.3 Sensitivity Analysis of External Drivers

This chapter assesses the impact of variations in the External Drivers on the model results.

Grid Expansion Costs When grid expansion becomes more expensive, system costs increase but the required grid expansion itself does not change substantially. The installed capacity of lithium-ion batteries rises slightly, while iron-air deployment remains largely stable (Table 4.7). This indicates that the grid expansion modelled in the benchmark scenario is a necessity rather than a flexible design choice.

In contrast, when grid expansion costs are reduced, the model chooses significantly more grid expansion. This results in almost a halving of both lithium-ion and iron-air battery capacities. Table 4.7 shows this shift clearly. This suggests that part of the battery deployment in the benchmark scenario is motivated by deferring costly grid upgrades. Once grid expansion becomes cheaper, the system pivots back towards transmission infrastructure as a cost-effective solution.

Table 4.7: *Sensitivity analysis summary for Grid Costs. Highlighted values indicate deviations of more than 10% from the benchmark scenario.*

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Grid costs max	20.05	0.59	11.14	483.83
Grid costs min	9.68	0.25	16.43	124.97

CO_2 Emission Target Sensitivity Stricter CO_2 caps lead to substantial increases in iron-air battery deployment and grid investment, while lithium-ion capacities remain unchanged (Table C.4). This aligns with the interpretation that iron-air batteries primarily replace CCGT and coal as baseload providers in low-emission scenarios. Lithium-ion, again, does not play this role and appears to be used for intra-day balancing, which is less impacted by CO_2 constraints.

Demand Growth Table C.6 shows that the model results are largely affected by variations in electricity demand. Increases in electricity demand lead to significant increases in both battery storage deployment and grid expansion requirements, as can be seen in Figure 4.16. The figure shows system's nonlinear response to growing demand: beyond a threshold (located between 242 TWh and 303 TWh) more radical battery investments are required. Grid investments start to increase drastically for a threshold between 303 TWh and 363 TWh.

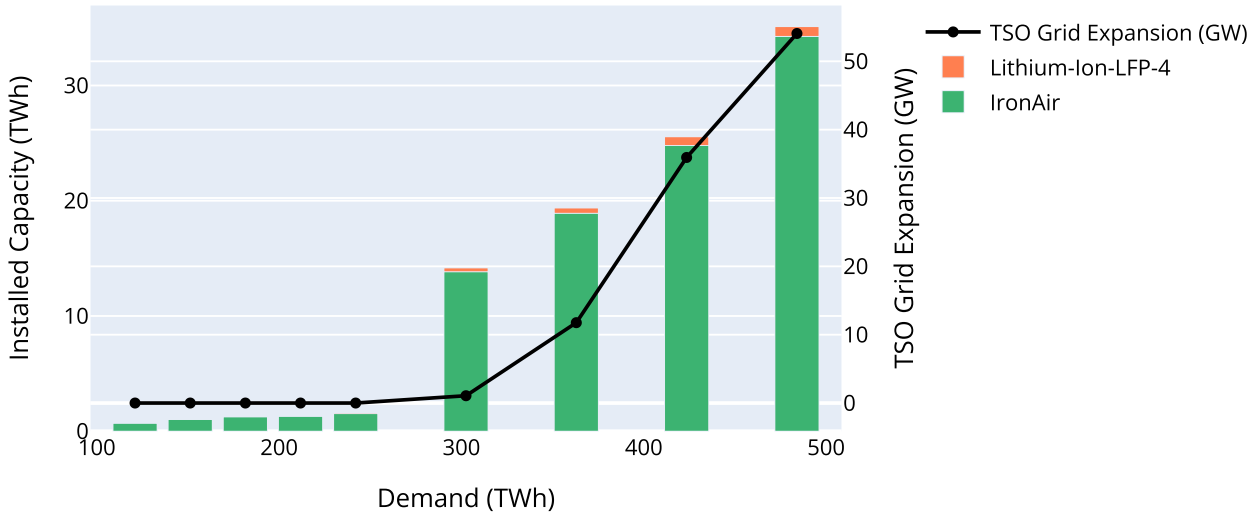

Figure 4.16: Changes in installed battery capacity and required grid expansion plotted over variations in electricity demand.

4.4.4 Testing Robustness Across Input Parameter Ranges

This chapter uses the results of the sensitivity analysis above to determine the ranges of input parameters for which the model results remain robust. However, the model's ability to represent reality is not solely dependent on these Policy Levers and External Drivers inputs. It also depends on how accurately the relationships within the model (the "R" in the XLRM framework) reflect real-world dynamics. These relationships are shaped by internal model assumptions, which are therefore a crucial factor in assessing model validity. The influence of these assumptions is discussed in Chapter 6.2. By doing so, all the components of the XLRM framework are addressed.

Table 4.8 shows the input parameter ranges over which the results of the 2040 scenario remain robust. The focus is solely on the required grid expansion, as we consider this to be the most critical outcome metric and for reasons of clarity and readability of the table. Variations in other performance indicators, such as the installed capacity of iron-air or lithium-ion storage, are not taken into account here. The table shows that changes in lithium-ion and iron-air parameters do not significantly influence the total required grid expansion. This metric does change substantially when grid costs are lower than their benchmark value. Besides, a CO_2 target or electricity demand other than the benchmark scenario also causes significant changes in required grid expansion.

Table 4.8: Overview of sensitivity test scenarios and their impact on required grid expansion. The table presents variations in input parameters and whether changes within their reported minimum and maximum values significantly affect the modelled grid expansion (changes in storage mix and total system costs have been neglected). If the variation does not lead to a deviation of more than 10% from the benchmark scenario, the full range is robust. The full version of this table is presented in Confidential Appendix A.

Scenario name	Abbre-viation	Full name	Benchmark value	Min value	Max value	Robust for full parameter range?	Robustness condition[1]
Lithium-ion	Costs	Total project CapEx	€ 300 / kWh	€ 250 / kWh	€ 355 / kWh	Yes	min $\leq$ costs $\leq$ max
Lithium-ion	FOM	Fixed Operating and Maintenance costs	0.35 % / year	0.2 % / year	2.5 % / year	Yes	min $\leq$ FOM $\leq$ max
Lithium-ion	RTE	Round Trip Efficiency	84.55 %	83 %	86 %	Yes	min $\leq$ RTE $\leq$ max
Lithium-ion	LT	Lifetime	12 years	10 years	16 years	Yes	min $\leq$ LT $\leq$ max
Iron-air	Costs	Total project CapEx	Confidential	Confidential	Confidential	Yes	min $\leq$ costs $\leq$ max
Iron-air	FOM	Fixed Operating and Maintenance costs	Confidential	Confidential	Confidential	Yes	min $\leq$ FOM $\leq$ max
Iron-air	RTE	Round Trip Efficiency	Confidential	Confidential	Confidential	Yes	min $\leq$ RTE $\leq$ max
Iron-air	LT	Lifetime	Confidential	Confidential	Confidential	Yes	min $\leq$ LT $\leq$ max
Grid	Costs	Total project CapEx for grid expansion	5.9 million € / km	1.26 million €/ km	10 million €/ km	Partly	Benchmark $\leq$ costs $\leq$ max
CO_2 target		Limit of CO_2 emissions	13 megatons	10 megatons[2]	16 megatons[3]	No	Target = Benchmark
Hydrogen cavern storage			No integration	Integration	n.a.	Yes[4]	Benchmark and inclusion of hydrogen storage
Demand		Electricity demand	3 times[5]	1 time[5]	4 times[5]	No	Demand = Benchmark

[1] The notation "min $\leq x \leq$ max" indicates that the required grid expansion does not change significantly for any parameter value within the full range from 'min' to 'max'.
[2, 3]: These values have been chosen based on an educated guess of ±25%.
[4]: The storage mix does change substantially due to the addition of hydrogen, but the required grid investments do not.
[5]: These values are the multipliers with respect to the 2023 electricity demand of 121 TWh per year. The benchmark value (with a multiplier of three) is an estimation for the electricity demand in 2040 (see also Chapter 3.6).

5 Qualitative Interview Results

This chapter presents the results of three semi-structured interviews conducted to understand the business implications and implementation challenges of SDES and MDES technologies. The interviewees were selected based on their expertise and relevance to the Dutch electricity grid context, as detailed in Chapter 3.7. Not all questions were posed to every participant, due to differences in expertise and background. Questions concerning regulations were asked to both ACM and TenneT employees, as both encounter regulatory matters in the course of their work. Questions with a stronger focus on the technical aspects of storage technologies or the future transmission network were directed exclusively to TenneT, given their specific expertise in these areas.

The chapter discusses two main topics. It starts with the differences between various flexible assets such as demand-side response and battery storage and discusses the incentive issues in asset deployment, as discussed in Chapter 2.4.2. This data is used to address the fourth sub-research question, which examines the business implications and barriers to implementation. Thereafter, it discusses the comparison between this study's modelling results and those of the Netbeheer Nederland scenarios, as outlined in Chapter 4.4. This information is used to determine which modelling assumptions have the biggest impact on a potential mismatch between modelling results and reality, and therefore contributes to the third sub-research question that examines the influence of modelling assumptions.

5.1 Ownership Challenges and Differences Between Flexible Assets

This section discusses the relevance of MDES by comparing it to other flexible assets and discussing implementation barriers.

Different Asset Characteristics and Grid Flexibility needs

TenneT notes that the energy system is transitioning from a largely plannable, fossil-based setup to one dominated by renewable electricity. This shift demands a greater degree of flexibility to cope with variability in generation and demand. The TSO requires flexibility in many different ways; ranging from fast reserves in FCR markets to compensating for the lack of inertia due to a decreasing number of thermal power plants in the grid. Therefore, all types of flexible assets will be needed to support this transition. Storage (including both SDES and MDES systems) is one of the options to facilitate this flexibility need, yet not the only one.

TenneT also recognises the importance of multi-day storage technologies to fill the gap that exists between one-day and two-week supply lulls. Currently, expensive power-to-gas technology is used to fill this gap. However, if battery technology advances into MDES it becomes possible to fill the gap with batteries, which is a more cost-effective solution. Next to that, one participant commented that SDES technologies are not ideal for storing wind energy, as wind usually lasts longer than two to four hours, thereby acknowledging the need for multi-day energy storage as well.

Ownership and Market Responsibility

All three participants agreed that the responsibility for the deployment and operation of flexible assets should lie with market actors rather than grid operators. This structure is considered more efficient and enables better utilisation of battery functionalities, especially as market parties can access multiple revenue streams across electricity markets. In contrast, if grid operators were given an exemption to install and operate batteries, their use would be restricted to congestion management, leaving the prohibition to trade on electricity markets intact. Using a battery solely for congestion management does not require constant operation, for example as congestion at certain substations may only occur few times per year. Limiting the battery use to congestion management alone would underutilise its full potential and lead to inefficiencies, as the battery could also be used to trade on electricity markets in the meantime.

Current Incentives Interviewees are uncertain about whether market parties are currently sufficiently incentivised to install flexible assets for congestion relief. They point out that it is difficult to assess whether this is the case, and it is something only known in hindsight. The ACM employee indicates that the market will, at a certain price, always be willing to bear responsibility for the deployment of flexible assets. Besides, they point out that the regulations have been changed recently in favour of flexible grid usage and that it takes time for the market to respond and make use of the available tools. This is partly due to the fact that market parties must be aware of these new tools, but also because the development and adaptation of new products and systems takes time. Lastly, the ACM employee indicates that it is difficult to require existing customers with fixed contracts to behave flexibly, as they currently lack sufficient incentives to do so. TenneT employees indicated that market actors may require support if the market does not function properly and the right incentives are not in place, especially during the transition phase of the energy system. Besides, they indicate that additional measures, such as a capacity remuneration mechanism, can be introduced if system adequacy cannot be guaranteed.

Coordination One of the participants emphasised that in addition to well-functioning markets and appropriate incentives, greater coordination between stakeholders is essential. Specifically, government guidance on the spatial deployment of flexible assets is lacking. Batteries are currently being deployed in congested areas, even where grid expansion is already planned. Coordination is needed to ensure a stable energy system that can run on renewables at all times.

Grid-Friendly Behaviour One participant remarked on the difficulty of ensuring that batteries operate in a grid-supportive manner. Because large-scale battery systems are still relatively new, there's a lack of long-term operational data, and their behaviour can potentially lead to congestion if not managed properly. For example, large storage facilities can create a constant risk of congestion, particularly when the ratio between grid capacity and storage capacity is unbalanced and the facilities are allowed to charge/discharge at full capacity at any moment.

An ideal situation would guarantee grid-friendly behaviour without compromising the flexibility that batteries can offer. However, this is difficult to achieve. New regulations such as the TDTR prevent actors from feeding electricity into the grid during peak hours and thereby promotes grid-friendly behaviour, but it also limits the flexibility these actors can provide. A system that enforces grid-friendly behaviour without sacrificing flexibility would therefore be optimal, but is difficult to realise in practice. Hence, grid operators must consider worst-case behaviour of actors, which limits the available grid capacity. Capacity that is scarce and needed to connect renewable energy farms and flexible assets to the grid.

5.2 Grid Expansion versus Battery Implementation

Interviewees with a technical background were asked to comment on the comparison between the modelling results of this study and the scenarios from Netbeheer Nederland (2023c), as discussed in Chapter 4.4.1. These two models are renamed Model A and Model B, respectively, and their comparison is presented in Table 5.1. This table is used as starting point to understand the potential trade-off between transmission grid expansion and the implementation of BESS. Interviewees agreed that battery systems can help reduce the need for grid expansion, although not entirely eliminate it. Reasoning behind this is discussed in the paragraphs below.

Table 5.1: *Comparison of model outcomes highlighting a potential trade-off between transmission grid expansion and BESS implementation*

	Model A	Model B
Total generator capacity (on-/offshore wind, solar, coal, etc)	**156.6 GW**	**129.8 GW**
Total flexible assets	**217.7 GW**	**46.8 GW**
> Batteries	217.7 GW	22.7 GW
> Interconnection	–	12.8 GW
> Demand Side Response	–	2.0 GW
> Power-to-heat/gas	–	9.3 GW
Required TSO grid expansion	**8.4 GW**	**64.8 GW**

Cost-optimisation versus market trends Interviewees indicate that the Netbeheer Nederland scenarios are not based on cost-optimisation but rather serve as system forecasts grounded in market trends. This approach is taken because grid operators are not permitted to plan the energy system, but only the grid. The energy system is expected to evolve autonomously through market forces. Grid operators aim to maintain the resilience and robustness of the grid while remaining technologically neutral. Therefore, their future scenarios include various types of flexible assets, as these enhance system robustness due to their differing characteristics and ensure non-discrimination among technologies. However, it is difficult to predict the future installed capacity of these flexible assets, as this depends on market forces. Consequently, it is also challenging to estimate the extent to which we can rely on them to prevent future grid investments.

Security of supply Besides, they indicate that a system relying solely on batteries as flexible assets carries a relatively high risk of energy unavailability. In grid planning scenarios, conservative figures are often used to ensure that uncertainties in assumptions (technology costs, adoption rates) do not result in under-planned grid expansions. Security of supply must not be at risk due to such uncertainties.

Interconnection The Netherlands' interconnectedness with surrounding countries means that some degree of grid investment remains essential. The Netherlands will be a net producer due to the large potential with offshore wind in the North Sea. Energy can be harvested and transported to Germany and Belgium, which requires grid capacity.

Asset price versus market price of flexibility One interviewee noted that the savings achieved through avoided grid expansion cannot be reinvested in battery systems directly due to regulatory constraints. Current regulations prohibit grid operators from owning or operating batteries, meaning any flexibility must be procured via congestion management mechanisms. These mechanisms allow grid operators to buy flexibility from market parties. This presents a challenge, as compensation demanded by market actors for providing flexibility services is not equal to the the cost price of the asset, but rather a market price of the delivered service. The price that these actors will ask must compensate for their missed revenue, and will therefore be higher than the cost price of the asset.

6 Discussion

This chapter reflects on the key findings of this research, evaluates the applied research approach, and interprets the modelling and interview results in the broader context of the Dutch energy transition. Furthermore, it explores the policy implications and presents recommendations for overcoming the identified regulatory and incentive barriers. Finally, the chapter discusses the study's limitations.

6.1 Summary of Key Findings

This research set out to investigate to what extent SDES and MDES technologies can defer transmission grid expansion investments in the Netherlands under conditions of increased renewable energy penetration. The findings of both the quantitative modelling and the qualitative interviews provide a comprehensive view on the technical potential and practical limitations of this deferral.

The modelling results clearly demonstrate the complementarity between SDES and MDES technologies. SDES, such as lithium-ion batteries, are well-suited to address high-frequency fluctuations caused by solar PV generation, whereas MDES technologies, like iron-air batteries, effectively handle the multi-day variability of wind generation. By combining both technologies, the system benefits from both short-term flexibility and resilience against prolonged renewable generation deficits.

While BESS technologies can indeed reduce the need for TSO grid expansion, this effect is not unlimited. The model indicates that significant transmission investments can still be avoided when storage assets are deployed at scale; however, factors such as increasing electricity demand and the importance of security of supply ultimately require some level of grid expansion to ensure system adequacy. In essence, storage can shift but not eliminate the need for transmission upgrades.

Moreover, the degree to which TSOs can rely on BESS for congestion management depends strongly on market dynamics. The deployment of storage assets is primarily market-driven, and private actors are more likely to install BESS for arbitrage opportunities in wholesale and balancing markets rather than for targeted congestion relief. Whether these storage assets become available to TSOs for congestion management purposes depends on the market structure and the incentives provided. Hence, the design of market rules and regulatory frameworks is crucial. Incentive schemes that stimulate the installation and optimal utilisation of flexible assets are vital to achieve a cost-effective and efficient energy system where storage can support congestion relief.

6.2 Reflection Upon Research Approach

This research applied a quantitative modelling approach to assess the impact of SDES and MDES on transmission grid investment deferral. Using the PyPSA-EUR optimisation model provided clear and quantifiable results, allowing for a direct comparison between different storage deployment scenarios. However, it is important to acknowledge that a model remains a simplification of reality. While it offers valuable insights into system behaviour under certain assumptions, it inevitably abstracts from many real-world complexities. Particularly in the context of energy system planning, dynamics such as stakeholder incentives, regulatory restrictions, and market structures play a crucial role but are not fully captured within the model boundaries. This creates a risk that the quantitative results could suggest definitive solutions, even though important external factors may influence the practical feasibility of the modelled scenarios.

Recognising these limitations, the inclusion of qualitative interviews added significant value to this research. By engaging with experts from the field, the interviews enabled a critical evaluation of the model outcomes and allowed for the exploration of implementation barriers that are otherwise difficult to quantify. In this way, the qualitative component complemented the quantitative analysis and provided a more holistic understanding of the potential and challenges of integrating flexible assets into the Dutch electricity grid.

Although the mixed methods approach strengthened the research, it also introduced certain limitations. Due to time constraints, only a limited number of stakeholders could be interviewed. This naturally restricts the generalisability and representativeness of the qualitative findings. Nevertheless, the interviews still proved to be highly valuable. The modelling phase served as a solid preparation for the interviews, providing a clear framework for discussion and ensuring that interview time was used effectively. In return, the interviews offered rich and nuanced insights that helped to contextualise and critically assess the modelling results, thereby enhancing the overall robustness of the study.

It is also important to reflect on the modelling scope itself. The PyPSA-EUR model operates on a total energy system level, optimising the entire system by balancing generation, storage, and transmission investments to minimise overall system costs. This system-wide perspective is highly relevant when determining the optimal deployment levels of SDES and MDES technologies across the full energy system. However, if the sole aim were to assess how batteries could operate for congestion relief at the level of a specific TSO substation or transmission line, a more focussed modelling approach would have been more appropriate. Such an approach could simulate the operational behaviour of storage assets strictly for local congestion management, for by assessing the impact of BESS systems upon one TSO substation or line. Yet, as became clear from the expert interviews, TSOs are unlikely to own or operate batteries purely for congestion relief purposes, as this would not be an efficient use of resources. Instead, flexibility assets are typically installed and operated by market parties with multiple revenue streams in mind. Therefore, while the system-level focus of PyPSA-EUR remains appropriate for this research, it is essential to acknowledge that the storage capacities implemented in the model are not dedicated solely to congestion relief but contribute to overall system optimisation.

Model Validity

A critical element in evaluating the research approach is the assessment of model validity. While the quantitative model offers valuable insights into system-wide outcomes, its reliability ultimately depends on both the chosen input parameters and the underlying modelling assumptions. To better understand the robustness of the findings, a sensitivity analysis (see Chapter 4.4) was performed.

The sensitivity analysis demonstrates that the results for the 2040 scenario are generally robust across the full range of lithium-ion and iron-air battery characteristics that were considered. Changes in these technology parameters do not lead to significant differences in the required transmission grid expansion. However, certain scenarios do exhibit notable shifts in the balance between SDES and MDES deployment, indicating that while total grid investments remain fairly stable, the distribution between specific storage technologies can be sensitive to input variations. The addition of hydrogen cavern storage likewise does not materially affect the extent of grid expansion but does substantially reduce the installed capacity of iron-air batteries, suggesting a clear substitution effect between long-duration storage technologies.

In contrast, the validity of the results is more sensitive to certain external factors. The outcomes remain robust only when grid expansion costs fall within the €5.9 to €10 million per kilometre range, and when the CO_2 emissions target and electricity demand are fixed at 13 megatons and 363 TWh, respectively. Within these boundaries, the model provides reliable insights. However, this robustness should not be mistaken for full real-world representativeness. The model's validity is inherently limited by its simplifying assumptions regarding weather data, demand patterns, operational uncertainties, and system flexibility. The remainder of this section elaborates on how these assumptions may shape the model outcomes.

Weather Patterns Assuming that future weather patterns are identical to those of 2023 neglects climatic changes. For instance, if Dunkelflaute events become more frequent or longer in duration, the model would underestimate the need for longer-duration storage systems such as MDES, which are specifically designed to deal with extended periods of low renewable generation.

Demand profile The future demand profile is modelled as a scaled version of today's hourly demand and therefore assumes no structural changes in the demand pattern, which may be unrealistic. For example, increased adoption of electric vehicles and electric cooking appliances may intensify peak loads in the evening, without significantly affecting baseload consumption. Ignoring such trends may lead to inaccurate estimations of the required grid or storage capacity.

Cost-Optimisation and Hindsight Approach By focusing solely on cost optimisation, the model configures the energy system in an extremely efficient, but potentially fragile, way. For example this may result in storage units being operated from 100% to 0% capacity, which is effective usage of the capacity but leaves no buffer for unexpected deviations in demand or supply. In the real world, such deviations are common due to forecasting errors or short-term fluctuations. Because the model knows supply and demand in advance, it effectively takes a hindsight-based approach and does not account for operational uncertainty. This puts the security of supply at risk, which is something grid operators must manage constantly.

Flexible Grid Usage The model assumes the grid can be used flexibly, which implies that generators can dispatch electricity if the grid has sufficient capacity and must curtail if it is full. This contrasts with the real-world system, where firm contracts often reserve grid capacity in advance, regardless of whether it is actually used. As a result, grid congestion can occur even when there appears to be enough physical capacity. Additionally, the model may suggest it is more economical to overbuild renewable generation and curtail the excess output instead of reinforcing the grid. However, TSOs do not have the mandate to make such trade-offs, as these decisions span different stakeholders.

Other Types of Flexible Assets The model does not include flexibility options such as interconnection, demand-side response, or power-to-x. This simplification ignores the fact that the Netherlands is tightly integrated with neighbouring countries and that these flexible assets can significantly reduce the need for both grid expansion and storage deployment. Besides, the assumption that SDES and MDES technologies are represented by lithium-ion and iron-air batteries respectively does not account for new technology breakthroughs that could shift the cost-optimal technology mix in the near future. Moreover, storage costs in the model are limited to capital investment, while in reality, the flexibility services provided by these assets often come at a premium—making actual storage costs higher than modelled.

Space Constraints Space constraints for deploying storage are also left out of scope. This helps to simplify the analysis and ensures the model's optimisation of storage capacity is not influenced by spatial limitations, it overlooks the practical limitations of installing large volumes of batteries, especially in a densely populated country like the Netherlands.

Overnight Approach The modelling approach assumes that all system changes can be implemented overnight. This neglects the staged nature of real-world infrastructure deployment, where investments are made iteratively and influenced by regulatory processes, permitting timelines, and supply chain limitations. As a result, the model may overestimate the speed at which the energy system can transition.

Generator Technologies Finally, although the type of generation mix could influence which type of battery technology is best suited, the model does not include a sensitivity analysis for generator parameters. The composition of the storage mix may be subject to change, based on the installed generator capacities and future technological advancements.

6.3 Interpretation of Results

Quantitative Modelling Results

The value of these modelling results lies in their ability to demonstrate the theoretically most cost-effective mix of technologies. Importantly, the results confirm that the effect of energy storage is indeed one of deferral, not elimination, of transmission expansion. The sensitivity analysis showed that increased electricity demand ultimately leads to greater transmission needs, and while storage can significantly reduce the scale of expansion required, it does not fully eliminate the necessity. Expert interviews were used to increase the understanding of these modelling results and their implications.

The interviews showed that the model identifies the most cost-effective energy system without considering which actors are responsible for implementing the assets. This is causes a mismatch with reality, because:

1. TSOs are not permitted to own or operate battery systems. Consequently, they would need to procure these services from market parties, paying the market price for flexibility rather than the asset cost assumed in the model. This implies that savings on grid investments (funds held by TSOs) cannot be directly reinvested in storage deployment, as market actors must operate the batteries. TSOs can request help from market parties using congestion management services, however this adds further complexities and additional pricing dynamics that are not represented in the model.

2. TSOs allow the market to determine which technologies are installed, meaning they do not actively plan for the most cost-effective energy system. Instead, they observe market trends and determine the required grid expansion on technology adoption estimates, including projections of battery deployment. While batteries can theoretically reduce the need for network reinforcement, TSOs cannot rely solely on these forecasts, given their uncertainty. They must prioritise robustness, resilience, and security of supply and therefore maintain sufficient transport capacity regardless of projected storage levels. Moreover, our model uses a cost-based objective and does not account for the risk of unserved energy. Interviewees indicated that an energy system solely relying on battery storage has an increased risk of energy not being served. As a result, even with increased battery deployment, network investments remain necessary.
3. The most cost-effective use of the transmission network implies installing as little new capacity as possible, due to the high cost of expansion. The model therefore prefers to over-install wind and solar capacity and allow for curtailment when the grid is saturated, rather than expanding transmission infrastructure. However, in the current energy system, this trade-off is not within the TSO's control; TSOs must ensure grid adequacy regardless of the cost-effectiveness of curtailment. Moreover, the model optimises for a single year and does not anticipate future developments. As such, even a modest future increase in electricity demand would necessitate further grid expansion.
4. The future composition of the energy system is not determined by TSOs or regulators (at most by the Ministry of Climate and Green Growth), but largely by the market. Whether the future system will resemble the modelled, cost-effective scenario depends on the regulatory environment and the incentives provided to market actors.

The modelling results should therefore be interpreted primarily in terms of the role that SDES and MDES technologies and the transmission grid can fulfil within the future energy system. While the precise cost-optimal installed capacities may vary depending on future developments, the underlying function of these technologies remains consistent. The true value of the results lies in identifying which technologies will form part of the future energy mix and how they complement one another in balancing supply and demand. This highlights the importance of technological diversity, as each technology serves a distinct role in managing different forms of variability. Such a diversified mix is essential to ensure the resilience and reliability of a decarbonised energy system dominated by renewable energy sources.

Qualitative Interview Results regarding Implementation Barriers

The qualitative findings suggest that, from a system efficiency perspective, the deployment and operation of flexible assets such as SDES and MDES should primarily be the responsibility of market parties rather than grid operators. Allowing market parties to own and operate these assets enables them to optimise revenues by participating in multiple market segments, including wholesale, balancing, and congestion markets. This approach ensures that storage assets are fully utilised and contribute effectively to system-wide flexibility, rather than being restricted to a single function such as congestion management. In contrast, direct ownership of storage assets by TSOs would likely lead to underutilisation, as regulatory restrictions prevent them from fully participating in energy markets. Even with exemptions, operational limitations would remain.

The interviews suggest that market parties are currently able to capture value streams for SDES by participating in several markets that reward short-term flexibility. Instruments such as the TDTR, which aims to limit peak injections into the grid, may further support business cases for SDES by creating incentives to avoid peak hours. However, it remains uncertain whether these mechanisms are equally effective in supporting the deployment of MDES. Since MDES primarily provides long-duration flexibility across multiple days, it is less clear whether current price signals or regulatory instruments sufficiently reward the specific value these assets offer. The question remains whether the existing market structure provides adequate incentives for both SDES and MDES deployment, or whether additional mechanisms may be needed in the future to stimulate investment in (long-duration) storage capacities that are critical for managing the intermittency of renewable energy sources.

The findings also indicate a need for improved spatial coordination between government, TSOs, and market actors. Without clear guidance on optimal locations, flexible assets risk being installed in areas where grid expansion is already planned, limiting their system-wide benefit. Stronger spatial planning frameworks or locational incentives may help ensure that both SDES and MDES are installed where they can contribute most effectively to grid stability and system efficiency.

Finally, while these interviews provide valuable insights, the limited number of participants means that the findings should be interpreted with caution. In particular, the absence of market party and policymaker perspectives limits the ability to fully assess how investment decisions around MDES might evolve under current or future market conditions.

6.4 Implications and Policy Recommendations

Regulators and Policymakers

Results show that the current grid is capable of facilitating an increased penetration of renewables when handled in a fully flexible way and integrated together with BESS. Grid capacity used to be handled in a rigid way, which causes some grid capacity to be left unused. This has resulted in scarcity and even hinders economic growth. The results show that integration of renewable energy sources to meet 2023 electricity is possible with current transmission grid capacity, if BESS are utilised and under the assumption that grid capacity is not rigidly assigned. Therefore, it is recommended that the regulatory environment incentivises market actors to adopt the various types of flexible assets, including SDES and MDES, and facilitates flexible grid usage.

The regulatory environment plays a large role in incentivising market actors, as the value of storage that they perceive depends on the regulations. For instance, the TDTR regulation allows TSOs to curtail electricity transport during 15% of the time, mainly targeting peak hours. One could argue that this regulation encourages the adoption of SDES technologies, as these peaks are usually intra-day. In such cases, the adoption of MDES technologies is not incentivised by this new legislation. This could create a discrepancy between the value of storage that individual market actors perceive, and the value it has for the total energy system.

Proper incentives and market structures will influence the adoption of these technologies. This influences market trends and allows grid operators to utilise the flexibility that these technologies offer and thus decreases the need for grid expansion. Yet, the degree to which grid operators can rely upon grid investment deferral by these technologies depends on these market trends and market adoption of the technologies. Therefore, regulators and policymakers must ensure that their regulations support the assets and technologies that contribute to the most cost-effective energy system. This focus should extend not only to SDES, but should include all types of flexible assets (MDES and seasonal storage solutions) since they all have a different role in our future energy system.

Transmission System Operators

The expansion of the grid remains necessary in scenarios of increasing demand, even with the integration of BESS. However, these flexible assets have been shown to reduce the required extent of expansion. Due to regulatory constraints, TSOs must rely on market parties to provide flexibility options. This reliance limits the degree of coordination that TSOs can exercise. Nevertheless, the social prioritisation principle (in Dutch: *maatschappelijk prioritiseren*) allows TSOs to prioritise parties that can alleviate congestion and thereby create additional grid capacity. It is therefore recommended that TSOs communicate where flexible assets would be most beneficial to the grid and make use of their prioritisation rights to enhance grid capacity. Still, extensive agreements are necessary to ensure that these parties behave in a grid-supportive manner.

Renewable Energy Farms and Industrial Actors

Given the scarcity of grid capacity and the time required to expand it, it is likely that flexible grid usage will be increasingly promoted and incentivised through regulations. Adding flexibility options helps reduce strain on the grid and is therefore recommended. This approach decreases dependence on the grid while maintaining continuous operations. The type(s) of flexible asset(s) to install depends on the supply and demand characteristics of a given process. For instance, wind farms are advised to install MDES technologies, whereas solar farms benefit more from SDES solutions. These technologies reduce grid usage during peak hours, thereby lowering curtailment and even creating additional revenue opportunities.

Battery Storage Developers

Further investments in R&D for cost-effective multi-day and seasonal storage technologies is advised. Such investments will help broaden the range of available flexibility solutions and support a more resilient and cost-effective energy system. Especially the total project CapEx (in €/kWh) is important systems with longer discharge durations, as they can perform fewer charge-discharge cycles, thereby reducing potential revenue.

Moreover, battery producers should focus on selling their batteries to market participants rather than to TSOs, as current regulations do not permit TSOs to operate batteries. Additionally, TSOs have shown little interest in doing so, as it is considered inefficient. Instead, market parties should install these batteries and offer congestion management services to TSOs.

6.5 Limitations

The modelling approach and underlying assumptions directly influence the quantitative results. The inclusion of other forms of flexible assets, the simulation of sector-coupled scenarios, or the integration of spatial constraints for battery siting could increase the accuracy and realism of the outcomes. Furthermore, the chosen cost-optimisation framework abstracts from the actor dynamics that characterise real-world decision-making; not all decisions in the energy system are purely cost-driven, and multiple stakeholders with differing interests shape investment decisions. These modelling boundaries are discussed in more detail in Chapters 6.2 and 6.3. It is important to note, however, that the model was intentionally designed to explore cost-optimal system configurations at the energy system level, rather than simulate individual actor behaviour.

In the qualitative part of the study, several implementation barriers were identified through expert interviews. However, due to the limited number of interviews conducted, the findings are unlikely to represent a complete overview of all possible barriers. The limited sample size also made triangulation of the interview insights challenging, as there was insufficient data to fully verify and cross-validate findings across different stakeholder groups. Additionally, no market parties were interviewed. While this was initially justified by their relatively low position in the power-interest matrix discussed in Chapter 2.4.3, the interview outcomes suggest that market parties are expected to play a central role in the deployment of flexible assets. Their absence limits the completeness of the findings, as their perspective is highly relevant to assess the practical feasibility and investment dynamics in future storage deployment.

Furthermore, the Ministry of Climate and Energy Policy (KGG) was not included in the interviews. The focus of this research was primarily on the current regulatory framework and operational challenges rather than on the formation of future policy. Nevertheless, the Ministry holds the authority to shape future market designs and create targeted policies that may incentivise or accelerate the deployment of flexible assets. Including their perspective would have enriched the analysis of possible future regulatory pathways.

Despite these limitations, this research provides meaningful insights into the potential role of flexible assets for transmission grid investment deferral and offers a valuable starting point for further research into the actor-specific and policy dynamics that will shape future storage deployment.

7 Conclusions

This chapter summarises the key findings of this research by answering the main research question and its corresponding sub-questions. The outcomes of both the quantitative modelling and qualitative interviews are integrated to provide a comprehensive perspective on the role of SDES and MDES technologies in deferring transmission grid investments in the Netherlands. Finally, this chapter outlines possible directions for future research, addressing the identified knowledge gaps and methodological limitations that emerged throughout the study.

7.1 Key Characteristics of SDES and MDES systems

Sub-Research Question 1: *What are the key characteristics, technological distinctions, and regulatory barriers associated with SDES and MDES systems?*

Effectively sizing the capacity and power characteristics of battery storage facilities requires a match between the discharge time of the battery system and the frequency of fluctuations in the power output it is designed to store and discharge. Wind energy typically exhibits lower frequency fluctuations compared to solar generation, the latter tends to vary on shorter timescales. As such, both SDES and MDES systems are necessary to effectively accommodate the differing characteristics of wind and solar generation.

This research selected lithium-ion batteries and iron-air batteries as representative technologies for SDES and MDES, respectively. Lithium-ion batteries offer high power and efficiency ratings, a long operational lifetime, and fast charging times. These features largely correspond to the suitability requirements for grid-scale SDES systems, as discussed in Chapter 2.2.1. In contrast, MDES systems place greater emphasis on energy capital costs, making iron-air batteries a fitting choice for this category. Although iron-air technology has not yet been widely adopted, it was chosen due to its potential alignment with the needs of multi-day storage. It should be noted that other technologies—such as salt batteries and flow batteries—also show promise in this space.

The stakeholder analysis conducted as part of this research revealed underlying incentive issues in the installation of flexible assets for congestion relief. Grid operators are currently not permitted to own batteries, which disables them from operating these batteries for congestion relief. Market parties, on the other hand, are driven by a profit maximisation approach and therefore seek to operate batteries on imbalance and other energy markets. However, participating in these markets does not always support the goal of relieving grid congestion. This regulatory tension and its implications are addressed more extensively under the fourth research sub-question, which includes insights from interviews with high-power, high-interest actors.

7.2 The Impact of Energy Storage upon Grid Investment Deferral

Sub-Research Question 2: *How do different energy storage scenarios — SDES, MDES, and a combination – affect the deferral of transmission grid expansion investments under increased renewable energy penetration?*
Sub-Research Question 3: *How do variations in model input parameters and modelling assumptions influence*

the outcomes of energy storage scenarios for deferring transmission grid investments?

The PyPSA model results illustrate the most cost-effective energy system for a 2040 scenario, where electricity demand has tripled compared to 2023 levels. Within this scenario, the deployment of $19.40\ TWh$ of capacity via SDES and MDES technologies reduces the need for TSO grid expansion to $11.8\ GW$. In contrast, a scenario without any storage requires $86.2\ GW$ of additional transmission capacity. This leads to a cost saving of €$1\ 613$ billion in grid investments. Furthermore, annual energy system costs are reduced from €$1\ 934$ billion per year to €321 billion per year. These yearly savings are not only due to the reduced transmission grid expansion, but also because of more efficient utilisation of renewable energy sources as less curtailment is required due to the ability to store electricity and fewer generation assets need to be installed because battery systems can be used to supply baseload electricity during periods with low wind and solar output.

This research shows that SDES and MDES technologies serve distinct yet complementary roles in deferring grid expansion and reducing system costs. SDES, represented by lithium-ion batteries, is optimised for managing short-term, high-frequency fluctuations—such as solar generation peaks—due to its rapid response and high power output. In contrast, MDES, modelled using iron-air batteries, is better suited to address multi-day or seasonal mismatches in renewable generation, particularly wind, thanks to its large energy capacity and longer discharge duration. While each technology individually contributes to grid investment deferral in the 2040 high-demand scenario, the most cost-effective outcome is achieved when both are deployed together, reducing required transmission expansion from $86.2\,GW$ to $11.8\,GW$ and lowering annual system costs by over €130 billion compared to MDES-only deployment. These findings highlight that a mixed deployment of SDES and MDES improves asset utilisation and decreases system costs.

The sensitivity analysis demonstrates that the model results for grid investment deferral are generally robust across a wide range of input parameters for both lithium-ion and iron-air technologies. Variations in technology costs, efficiency, or lifetime do not substantially alter the required transmission grid expansion, although they do affect the composition of the storage mix. For example, lower iron-air costs result in a shift towards higher MDES deployment, but the total transmission capacity required remains relatively stable. The addition of hydrogen cavern storage reveals a similar substitution effect, reducing MDES deployment without significantly impacting grid expansion.

The robustness of the outcomes is, however, more sensitive to certain external drivers. The results hold within a grid expansion cost range of €5.9 to €10 million per kilometer, and depend on fixed assumptions for electricity demand (363 TWh) and CO_2 emissions targets (13 megatons). Beyond these boundaries, the model outcomes may deviate. More importantly, while the sensitivity analysis ensures internal consistency of the model, it does not capture real-world uncertainties related to operational dynamics, spatial grid constraints, or actor behaviour. As such, the quantitative outcomes should primarily be interpreted as an indication of the system-wide role and function of SDES and MDES technologies, rather than precise forecasts of installed capacities. These limitations underline the relevance of complementing quantitative modelling with qualitative insights to assess the practical feasibility of storage deployment under actual market conditions.

7.3 Business Implications and Implementation barriers

Sub-Research Question 4: *What are the business implications and remaining implementation barriers associated with using BESS for grid congestion relief?*

The findings imply that the successful deployment of battery energy storage systems for congestion relief relies primarily on market parties taking responsibility for installing and operating these assets. By allowing market parties to participate in multiple market segments—such as wholesale, balancing, and congestion markets—storage assets can be utilised in a cost-efficient way, maximising their value across the system. This approach ensures that batteries are not limited to a narrow congestion management function, but contribute to broader system flexibility. In contrast, direct ownership by grid operators, while theoretically possible under exemptions, would likely result in underutilisation due to regulatory restrictions on energy market participation.

However, whether market parties are sufficiently incentivised to invest in flexible assets remains uncertain. While instruments such as the TDTR aim to promote grid-supportive behaviour, they may not yet provide strong enough financial signals to trigger large-scale (MDES) storage deployment for congestion management. If current incentives prove inadequate, additional regulatory adjustments may be required to better align private investment interests with the flexibility needs of the system.

The results also highlight spatial coordination as a critical implementation challenge. Without clear policy direction on optimal locations for flexible asset deployment, market parties risk installing batteries at locations at which grid expansion is already planned, potentially undermining system efficiency. Stronger coordination between government, TSOs, and market actors may be needed to ensure that the system-wide benefits of storage are fully realised.

Finally, while these findings offer valuable insights into the business implications and barriers to BESS deployment, the limited number of interviews conducted means that additional perspectives would further strengthen the understanding of practical feasibility and policy needs.

7.4 Future Research

Future research could focus on increasing model accuracy by refining the assumptions made during the modelling process. This would result in a more realistic representation of the most cost-effective energy system and could provide valuable input for policy development. However, it is important to note that such a cost-optimisation approach will inherently differ from the methodologies typically employed by grid operators, who base their projections on current market trends rather than purely on cost efficiency. Hence, while a more detailed and comprehensive model can improve insights, its usefulness remains limited to a certain extent. Ultimately, the model only presents the composition of the most cost-effective energy system, but the actual real-world implementation is driven by market forces and influenced by objectives beyond cost-effectiveness—such as security of supply and actor dynamics within the energy system. Including such considerations in the model would be highly complex but is necessary to enhance realism and practical relevance.

An interesting direction for future research lies in the implementation of storage technologies, especially MDES and seasonal storage. While SDES is currently more widely adopted, modelling results demonstrate that MDES and seasonal storage will be essential for providing baseload capacity as the Netherlands transitions away from gas and coal-fired generation. To support the practical implementation of these technologies, further research should address the following challenges:

- **Ensuring grid-friendly behaviour without compromising flexibility:** current regulations limit the access of storage technologies to the grid during peak hours, which in turn restricts their potential to provide valuable flexibility. Research is needed into how grid-friendly behaviour can be incentivised or enforced— preferably through simplified contracting mechanisms—while preserving the flexibility these assets can offer. If successful, this could alleviate the need for TSOs to plan for worst-case scenarios, thereby relieving grid congestion and facilitating greater deployment of SDES and MDES. Pilot projects could be useful to explore practical solutions for this.
- **Assessment of incentives for MDES and seasonal storage technologies:** although the modelling results underscore the future importance of these technologies, it remains unclear whether current regulatory and market incentives are sufficient to stimulate their deployment. Given the typically long timelines associated with legislative change and contract adaptation, it is crucial to evaluate whether existing mechanisms adequately encourage the adoption of MDES and seasonal storage.
- **Improving understanding of use-cases for MDES in industry and renewable energy farms:** expanding knowledge about the specific applications of MDES across different sectors—such as industrial users and renewable energy farms—could help drive adoption. This research suggests a stronger alignment between MDES technologies and wind energy, though this finding is based primarily on frequency analysis. More detailed research is needed to identify suitable industries, optimal technologies, and implementation strategies. For example, investigating the feasibility of deploying MDES offshore would be particularly relevant in light of the Netherlands' substantial offshore wind potential. Moreover, the sensitivity analysis in Chapter 4.4.2 highlighted the cost advantages of hydrogen cavern storage, warranting further investigation into its feasibility and a broader comparison of MDES and seasonal storage technologies.
- **Study of implementation barriers:** a broader investigation into the practical obstacles associated with deploying storage technologies—such as spatial constraints and regulatory hurdles—is needed. Such a study should also explore viable strategies for overcoming these barriers to ensure successful implementation.

7.5 Answering the Main Research Question

Main Research Question: *To what extend can Short-Duration Energy Storage (SDES) and Multi-Day Duration Energy Storage (MDES) technologies defer transmission grid expansion investments in the Netherlands under conditions of increased penetration of renewable energy sources?*

This research demonstrates that SDES and MDES technologies can play a significant role in deferring the need for transmission grid expansion in a future energy system dominated by renewable sources. Using a cost-optimisation model based on PyPSA-Eur, the results indicate that the deployment of $19.4\ TWh$ of storage capacity can reduce the required expansion of the Dutch transmission grid from $86.2\ GW$ to just $11.8\ GW$ by 2040. This is based on electricity demand tripling when compared to the 2023 demand. This translates to an investment saving of €$1\,613$ billion. Additionally, annual energy system costs are reduced from €$1\ 934$ billion to €321 billion. These cost savings are not only attributable to reduced grid investment but also stem from more efficient use of renewable generation: storage reduces curtailment, mitigates the need for overcapacity, and enables batteries to deliver electricity during periods of low wind and solar output.

Importantly, the modelling confirms that energy storage facilitates a deferral of grid expansion, not a full elimination. As electricity demand continues to grow, grid expansion remains a necessity, even in scenarios where storage is extensively deployed. The impact of SDES and MDES thus lies in their ability to delay and downscale investments, creating a window of opportunity to develop infrastructure more gradually and cost-effectively.

Both SDES and MDES serve complementary roles. SDES, represented in this study by lithium-ion batteries, is effective at managing intra-day fluctuations, particularly those associated with solar generation. MDES, represented by iron-air batteries, addresses multi-day supply lulls and is better aligned with wind power variability. Together, these technologies provide a balanced and flexible response to renewable intermittency. The results suggest that a combined deployment of both types of storage yields the highest system benefits.

However, the investment deferral observed in the model does not automatically translate into real-world deferral, due to several modelling assumptions. The model assumes perfect coordination and rational cost-based decision-making, but reality is shaped by a regulatory environment and complex stakeholder dynamics. For example, current Dutch regulation prohibits TSOs from owning or operating batteries. As a result, the flexibility must be procured from market actors—who are incentivised not by system efficiency, but by profit opportunities in energy markets. This creates a disconnect between the modelled ideal and actual deployment. Moreover, TSOs must maintain a high standard of reliability and cannot fully depend on uncertain projections of battery adoption. Consequently, even if batteries reduce theoretical grid needs, TSOs are likely to pursue grid expansion in practice to ensure robustness and security of supply.

This market structure could potentially hinder the adoption of flexible assets. Policymakers and regulators should ensure that market actors are properly incentivised to install MDES and seasonal storage solutions, and that regulations promote grid-friendly behaviour without compromising the flexibility these assets can offer. The value that market actors place on storage technologies is influenced by regulatory instruments such as the TDTR. These instruments should guide the market toward the most cost-effective energy system composition.

In conclusion, SDES and MDES technologies can significantly defer the need for transmission grid expansion under increased renewable energy penetration. The modelling outcomes highlight the scale of cost savings and system efficiency improvements that can be achieved through strategic deployment of storage. However, realising this potential depends on the regulatory environment and behaviour of market actors. While energy storage can substantially reduce the scale and urgency of grid expansion, it cannot entirely replace it. Next to that, the inclusion of other flexible assets is needed to ensure a robust and resilient energy system that is fully based upon renewables, without compromising the security of supply.

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A Confidential Appendix

This confidential appendix is only accessible to thesis supervisors and examiners.

B Interview Protocol

Part A: Responsibility & Implementation of Flexible Assets (20 min)

Objective: *Understand preference for type and ownership of assets.*

Flexible Assets:
Batteries
Demand-Side Response (DSR)
Interconnection
Power-to-heat
Power-to-gas

A1. When you look at the available flexible assets, which are favoured by your institute for alleviating congestion, and why?

A2. What is the benefit of energy storage for the TSO grid?

A3. Who should be in charge of installing and operating those preferred assets?

A4. Are the current market rules and incentives sufficient for that actor to install them?

Part B: Grid Expansion versus Implementation of Batteries (20 min)

Objective: *Understanding the potential trade-off between transmission grid expansion and the implementation of BESS.*

Background: *Flexible assets such as interconnection and DSR still depend on transmission grid capacity during periods of peak supply and demand. However, when batteries are deployed in a decentralized manner, this dependency is significantly reduced. According to Model A, the installation of 217 GW of BESS would require only an additional 8.4 GW of transmission grid capacity to meet the projected 2040 electricity demand with renewable energy sources. In contrast, Model B suggests a scenario with only 22.7 GW of BESS and a substantially higher expansion of 64 GW in TSO grid capacity, thus representing a model with significantly less BESS deployment and greater reliance on TSO expansion.*

	Model A	Model B
Total generator capacity (on-/offshore wind, solar, coal, etc)	**156.6 GW**	**129.8 GW**
Total flexible assets	**217.7 GW**	**46.8 GW**
> Batteries	217.7 GW	22.7 GW
> Interconnection	–	12.8 GW
> Demand Side Response	–	2.0 GW
> Power-to-heat/gas	–	9.3 GW
Required TSO grid expansion	**8.4 GW**	**64.8 GW**

B1. Which model is more realistic?

B2. Model B is one of the scenarios from Netbeheer Nederland (2023c), whereas model A represent the PyPSA modelling results of our study. What creates this difference between the two models? Is favouring grid expansion over batteries (model B) a choice based on the traditional planning mindset of grid operators, an outcome due to current regulations, or an actual technical necessity?
   a. Is this grid expansion focus due to the regulations that prevent TSOs from operating batteries?
   b. Current regulations do not incentivize batteries to be used for congestion relief. Why not?
   c. What creates the difference between the two models?

B3. If we follow the battery deployment of model A, would that indeed reduce the required grid expansion?
   a. Are there other limits not taken into account?
   b. Are there hidden downsides to battery storage?
   c. Is this future proof?
   d. Does this make decentralised battery storage more attractive than the other flexible assets?
   e. Why do we need other assets and therefore grid expansion?

B4. How do you see these strategies (relying on decentralised batteries, expanding grid capacity) evolve over the next decade?

Wrap-up (5 min)

1. If you could change one aspect tomorrow to speed up congestion relief, what would it be?

- Check for additional remarks;
- Explain that the transcript will be shared so the participant can comment on it;
- Thank the participant.

C Additional Figures and Tables

C.1 Research Approach

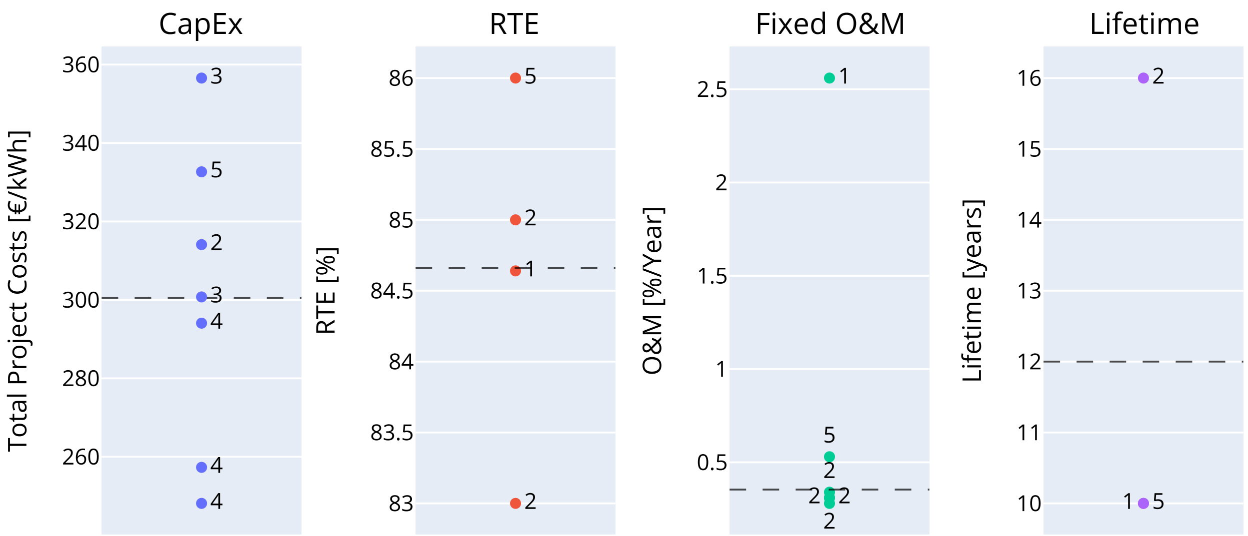

Figure C.1: *Comparison of existing values in the literature for key characteristics of grid-scale lithium-ion storage. Note that this plot shows a subset of the CapEx projections, only those for 2024 and beyond are displayed. The complete overview is presented in Figure 2.3. Besides, the Fixed O&M value of 2.56 % per year has been considered an outlier and is excluded from the analysis. Certain sources present multiple values and are therefore represented more than once in the graph.*
[1] Data from Giovanniello and Wu (2023); [2] Data from Viswanathan et al. (2022); [3] Data from Cole and Karmakar (2023); [4] Data from IRENA (2024); [5] Data from Mongird et al. (2020).

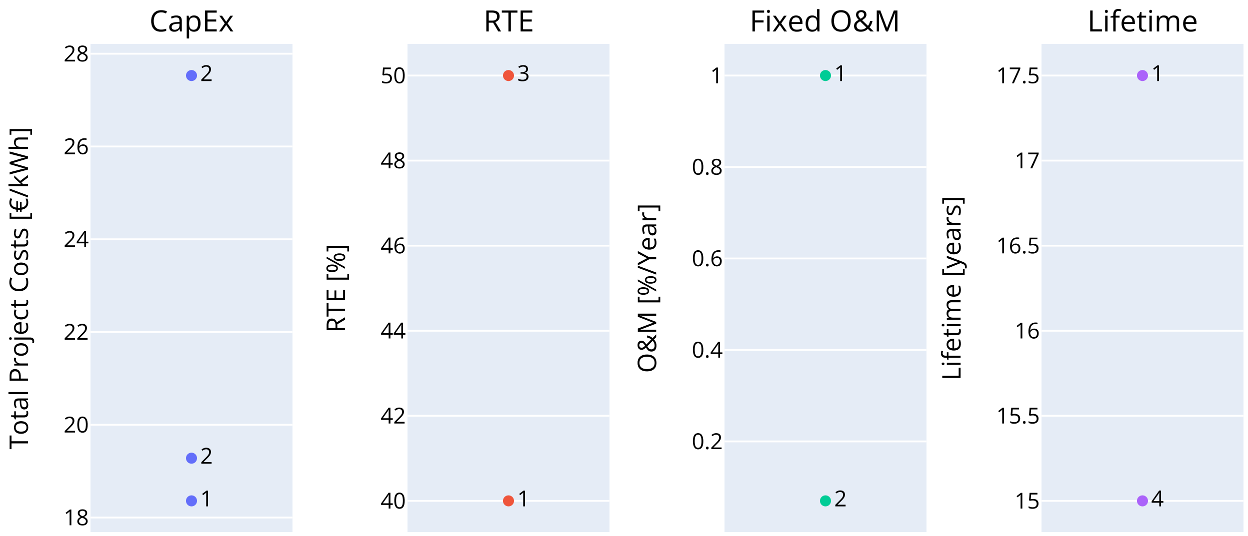

Figure C.2: *Comparison of existing values in the literature for key characteristics of iron-air storage. Note that this plot shows a subset of the CapEx projections, only those for 2025 and beyond are displayed. The complete overview is presented in Figure 2.4. Certain sources present multiple values and are therefore represented more than once in the graph. A confidential version of this graph is presented in Appendix A.*
[1] Data from Form Energy (2023); [2] Data from McKinsey and Company (2021); [3] Data from Argyrou et al. (2018); [4] Data from Narayanan et al. (2012).

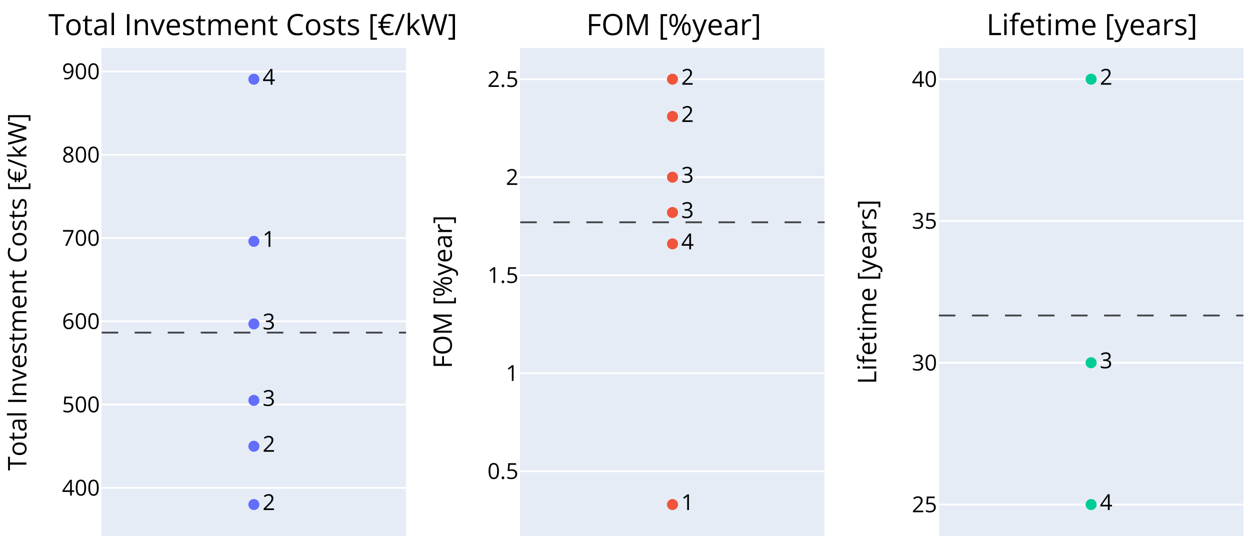

Figure C.3: *Overview of grid-scale solar technology parameters.* ***Note****: This analysis includes both fixed solar and solar-tracking technologies, as well as cost estimations from various years. Hence, some sources appear multiple times in the plot. The FOM value from IRENA (2024) varies substantially; but is not excluded since it relies on existing data rather than future assumptions and models and therefore deemed accurate.*
[1] Data from IRENA (2024); [2] Data from Danish Energy Agency (2025); [3] Data from Eveloy et al. (2025); [4] Data from Rahman et al. (2022)

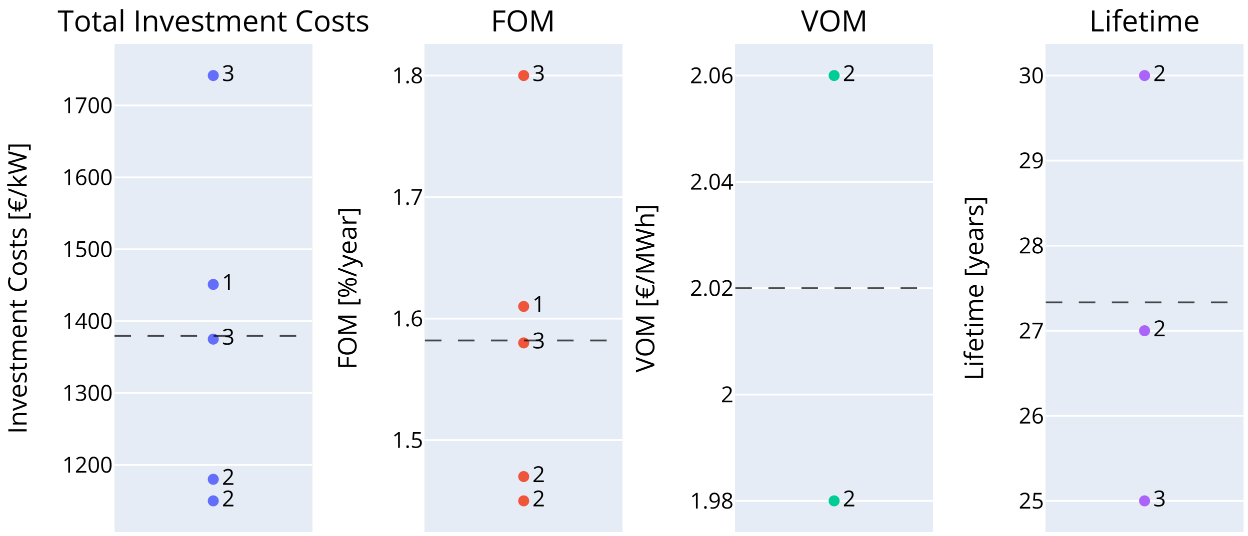

__Figure C.4:__ Overview of onshore wind technology parameters. VOM represents the Variable Operating and Maintenance costs. Certain sources present multiple values and are therefore represented more than once in the graph.
[1] Data from IRENA (2024); [2] Data from Danish Energy Agency (2025); [3] Data from Eveloy et al. (2025);

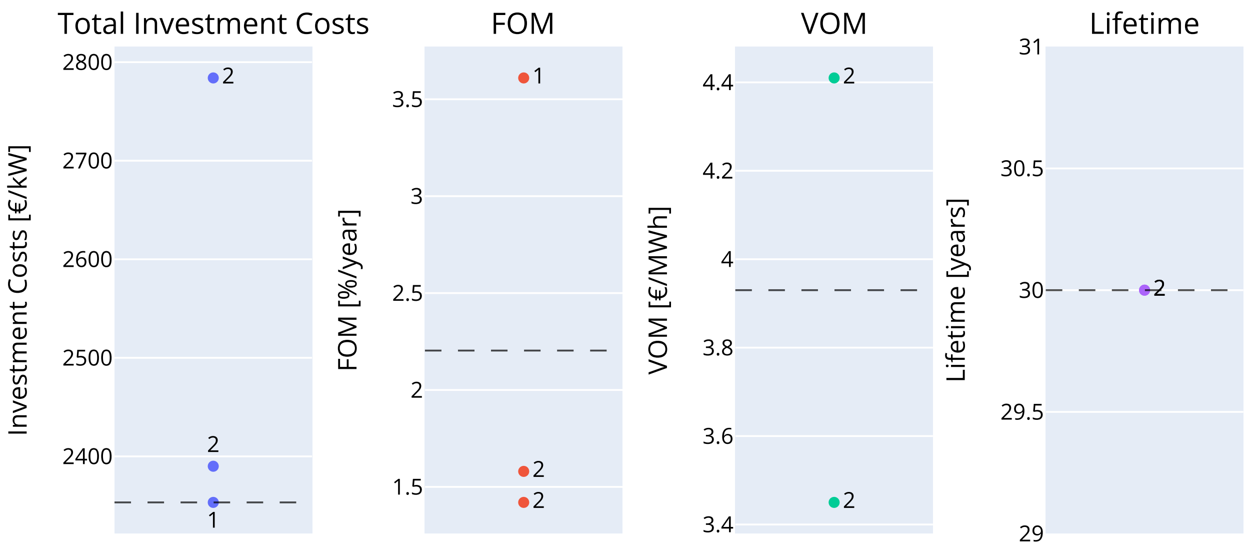

__Figure C.5:__ Overview of offshore wind characteristics. Certain sources present multiple values and are therefore represented more than once in the graph. __Note:__ The investment costs vary substantially based on sea conditions and type of turbines. IRENA (2024) has been used as final value for the total investment costs, since their analysis resulted in an average investment cost for offshore wind projects in the Netherlands.
[1] Data from IRENA (2024); [2] Data from Danish Energy Agency (2025).

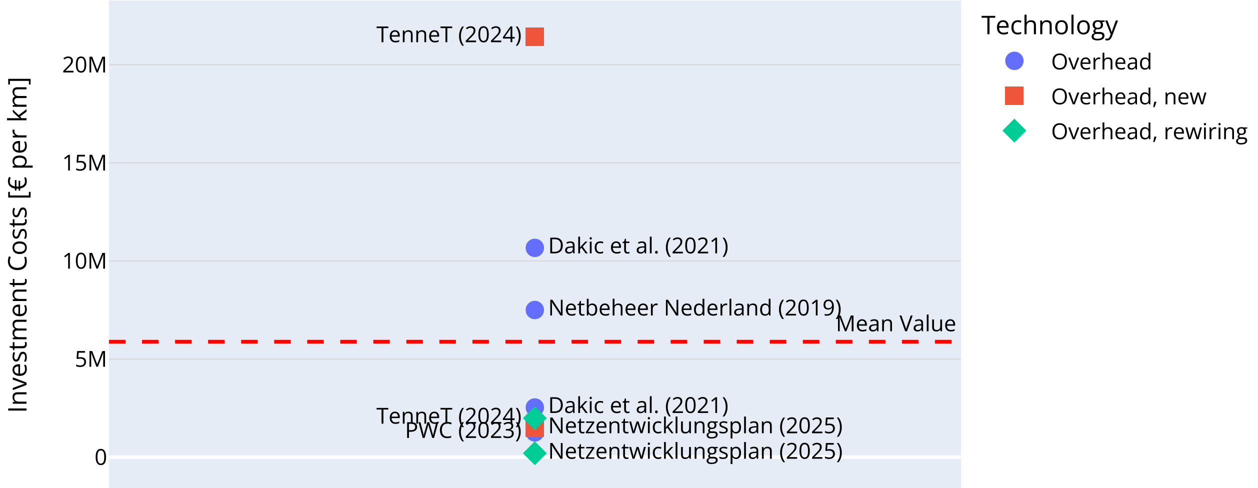

Figure C.6: Total project costs for expanding grid capacity by rewiring or installation of new 380kV, two circuits, overhead AC transmission lines. Certain sources present multiple values and are therefore represented more than once in the graph. ***Note 1:*** *M = Millions.* ***Note 2:*** *Additional information from RVO (2017, 2024) and TenneT (n.d.-a) was used to find the final €/Km values for the expansion projects of TenneT (2024).*

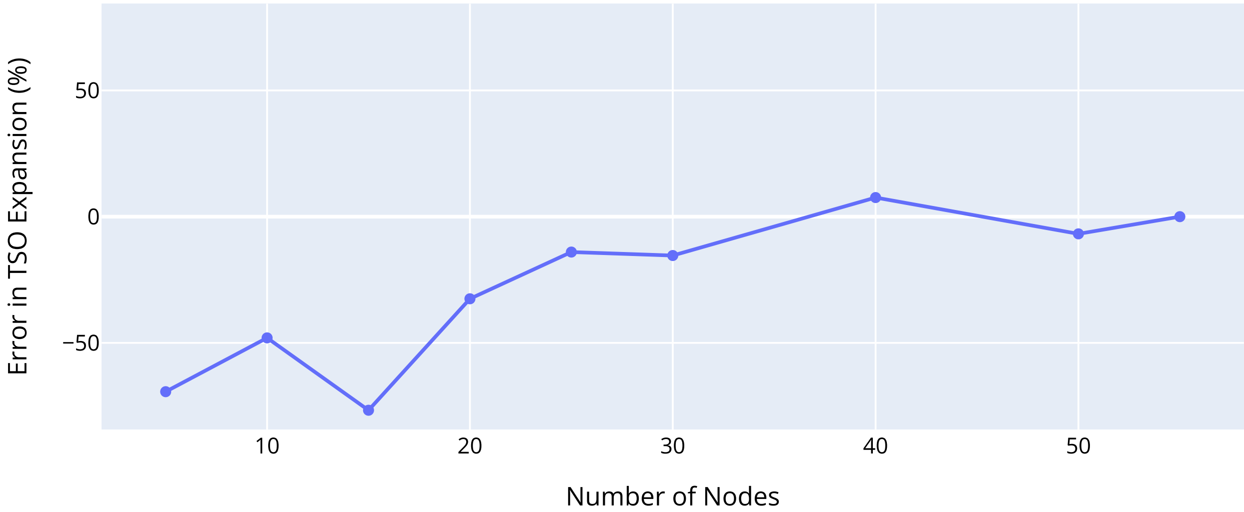

Figure C.7: Error in modelled TSO expansion results plotted against the number of nodes, assuming no error at the highest spatial resolution (55 nodes). Nodes serve as clustering units; hence, a higher number of nodes corresponds to a finer network resolution. Our study adopts 55 nodes for the simulation, representing the maximum level of detail.

C.2 Modelling Results

This chapter gives an overview of all modelling results.

2023 demand scenario

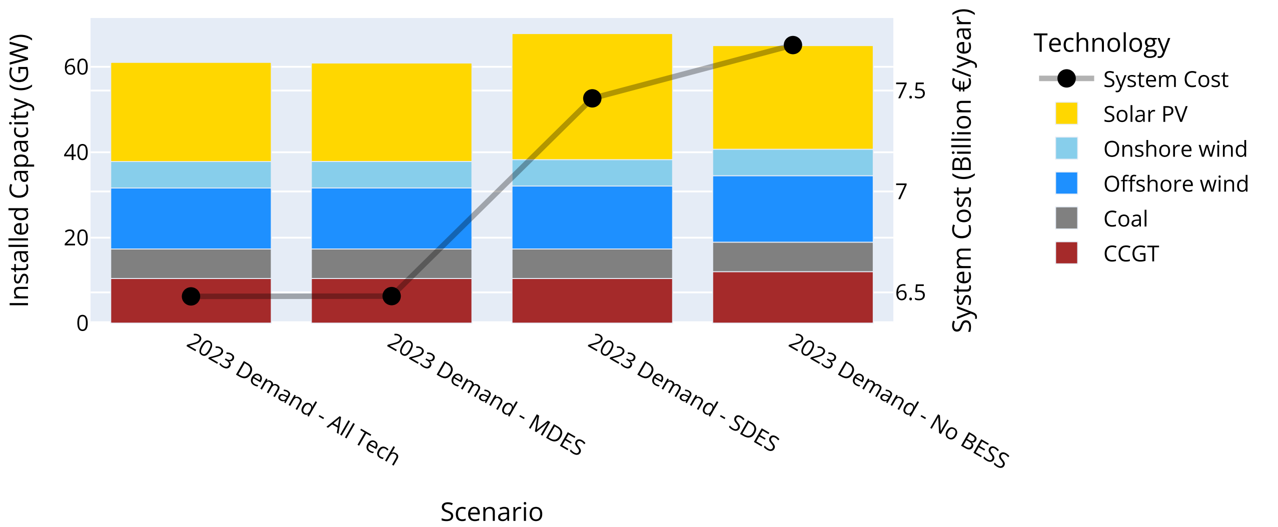

Figure C.8: Optimal generation capacities for 2023 demand scenarios

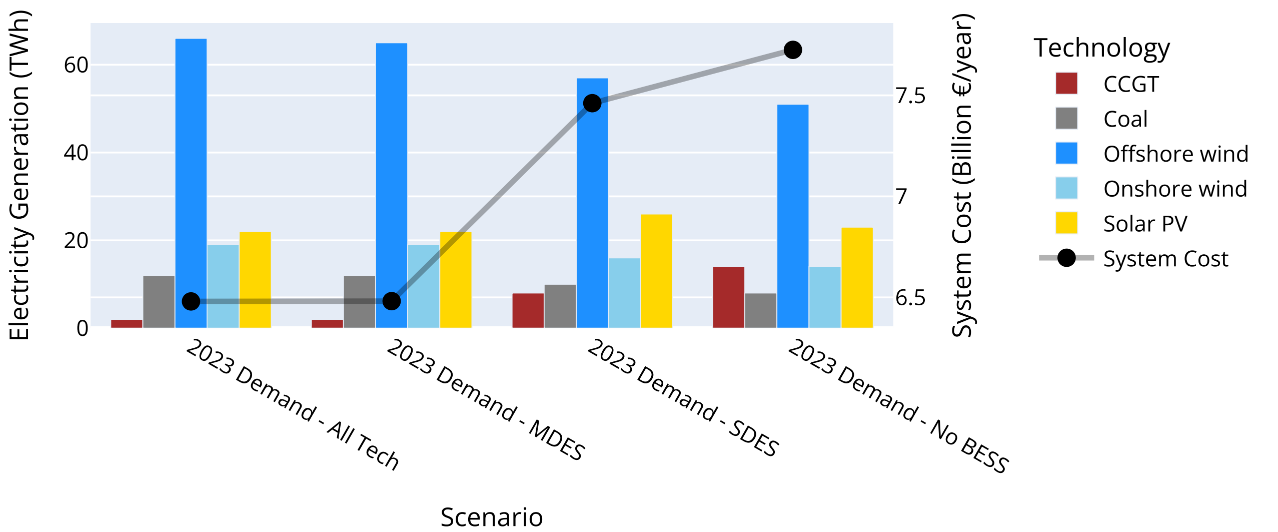

Figure C.9: Total electricity generation for 2023 demand scenarios.

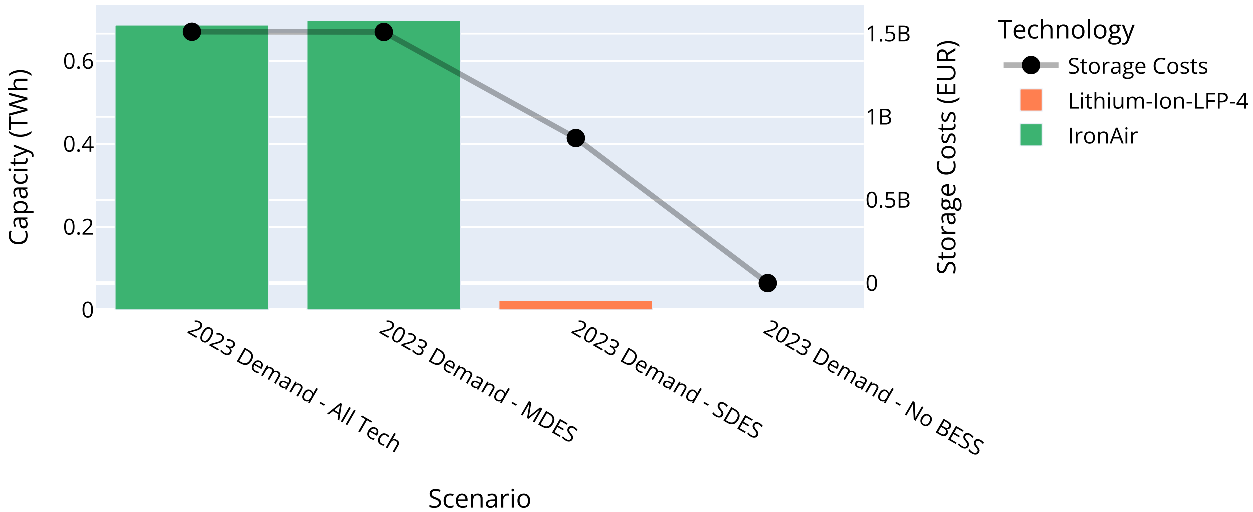

Figure C.10: *Optimal storage capacities for 2023 demand scenarios.*

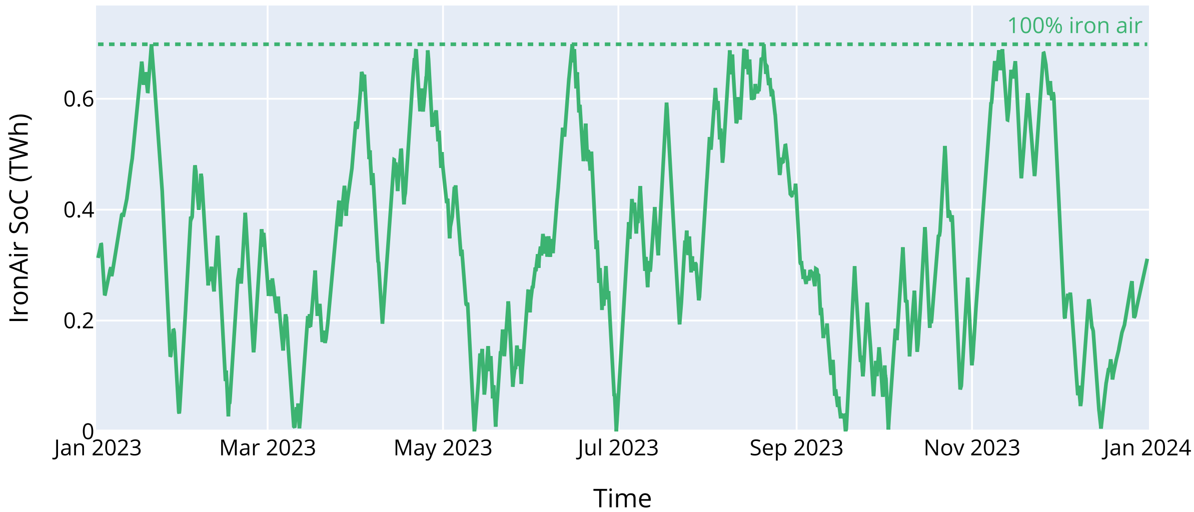

Figure C.11: *State of charge of batteries for MDES-only scenario with 2023 demand*

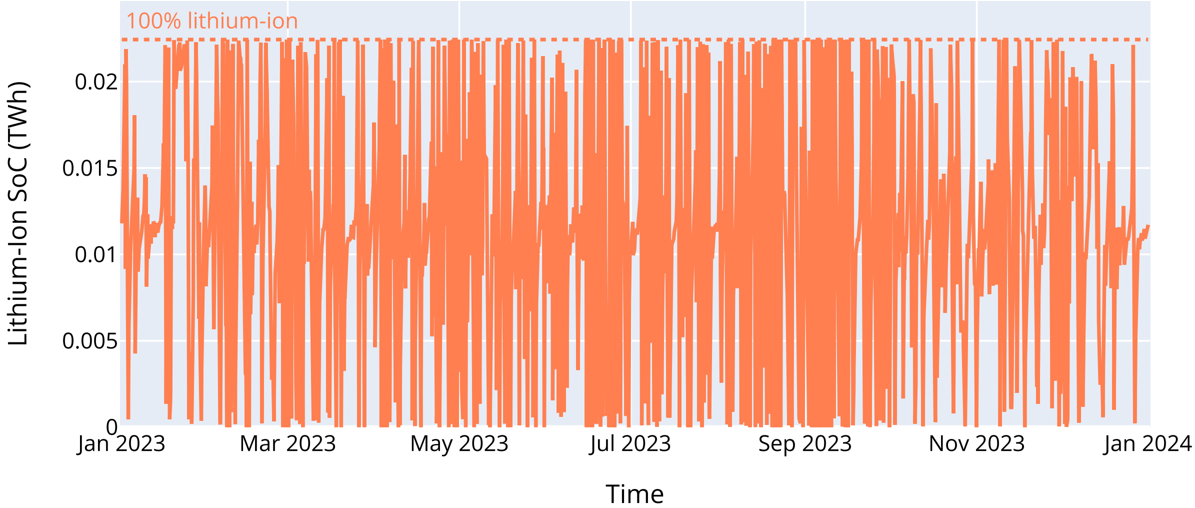

Figure C.12: *State of charge of batteries for SDES-only scenario with 2023 demand*

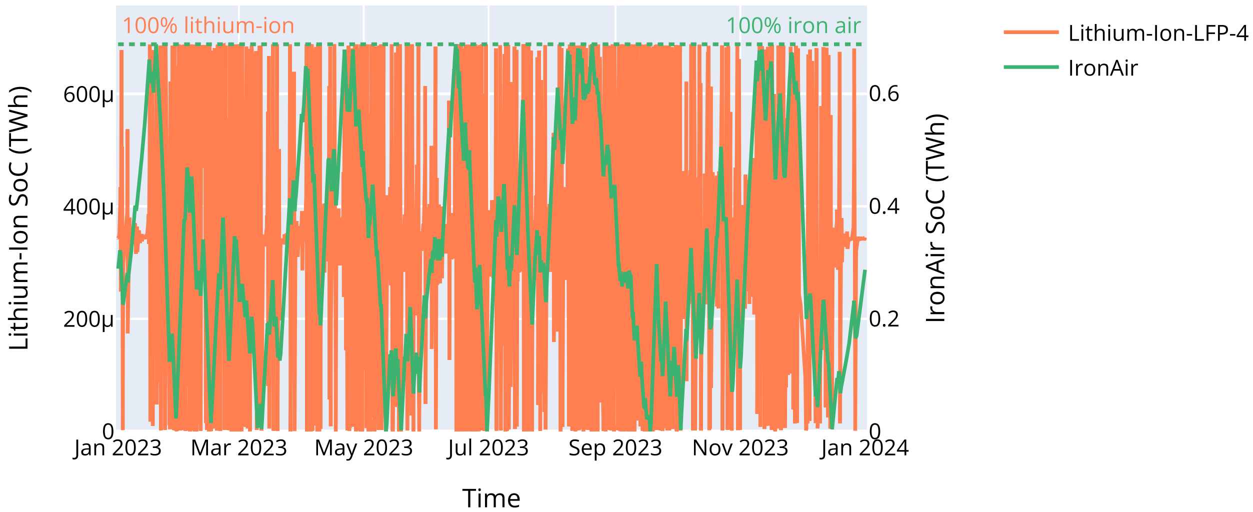

Figure C.13: *State of charge of batteries for a scenario with both SDES and MDES with 2023 demand*

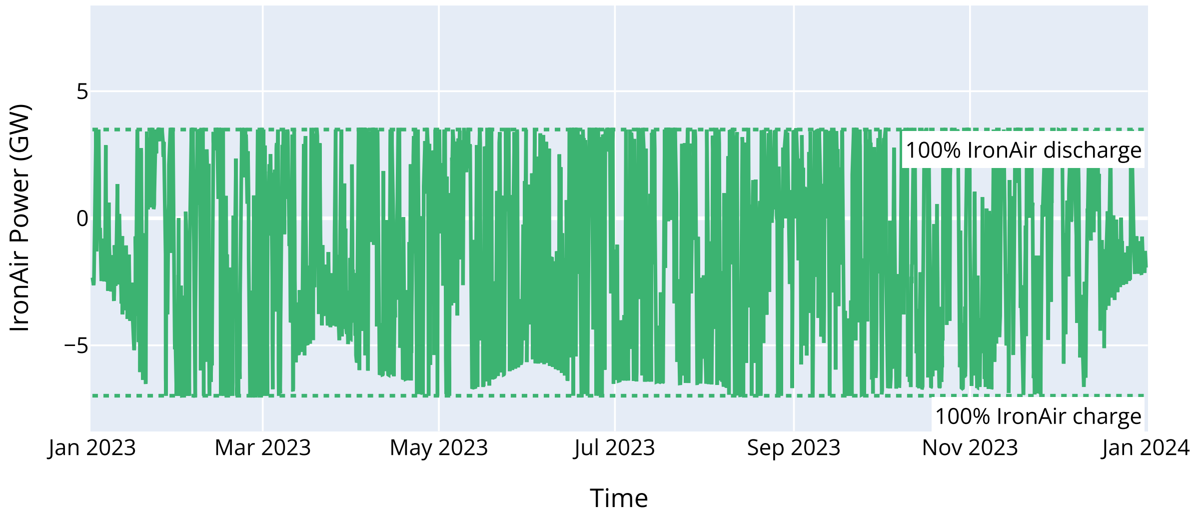

Figure C.14: *Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for MDES-only scenario with 2023 demand.*

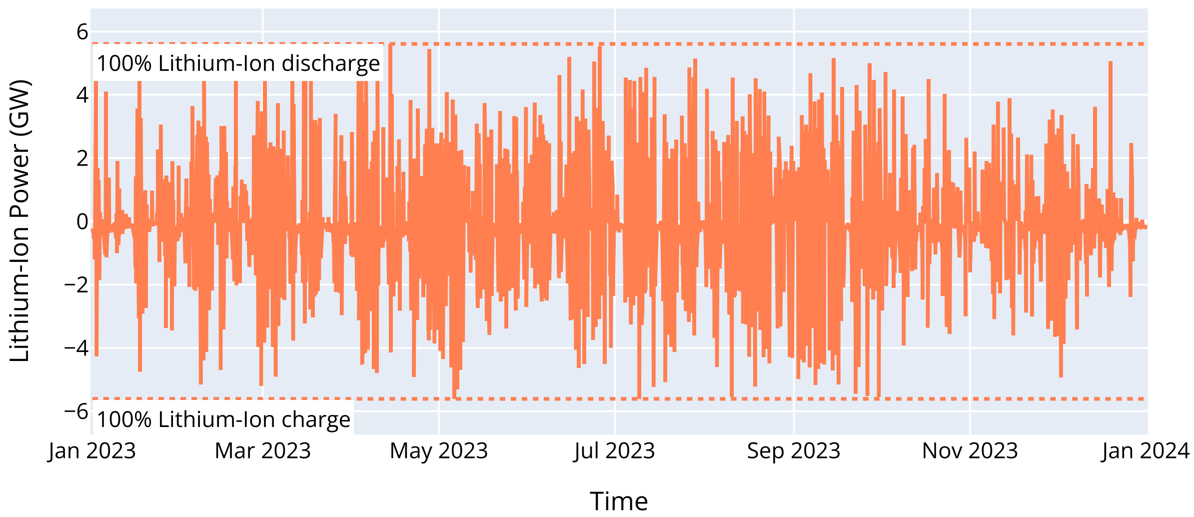

Figure C.15: *Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for SDES-only scenario with 2023 demand.*

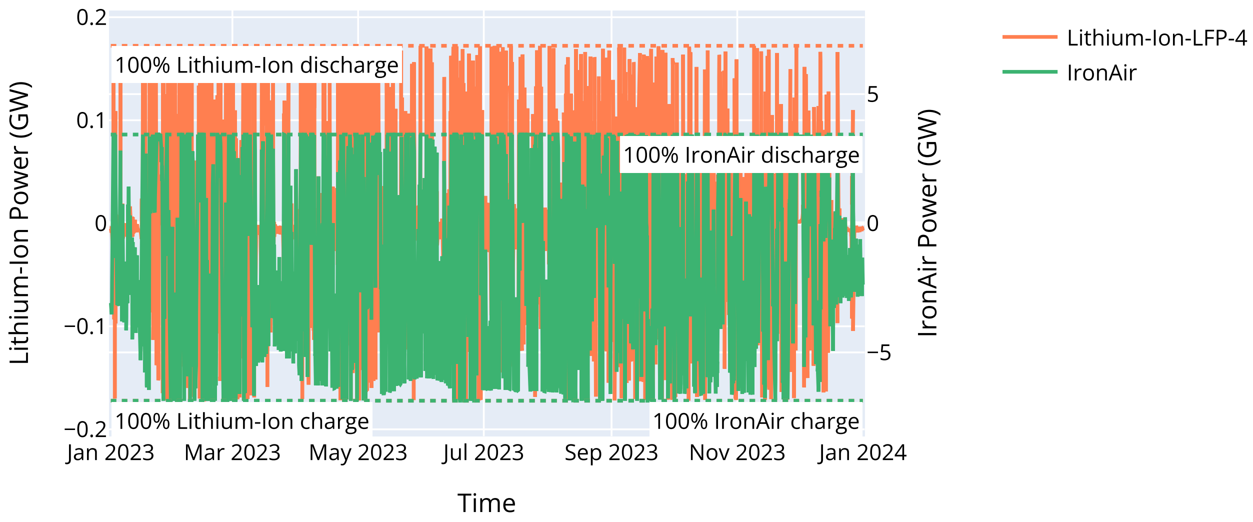

Figure C.16: *Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for a scenario with both MDES and SDES with 2023 demand.*

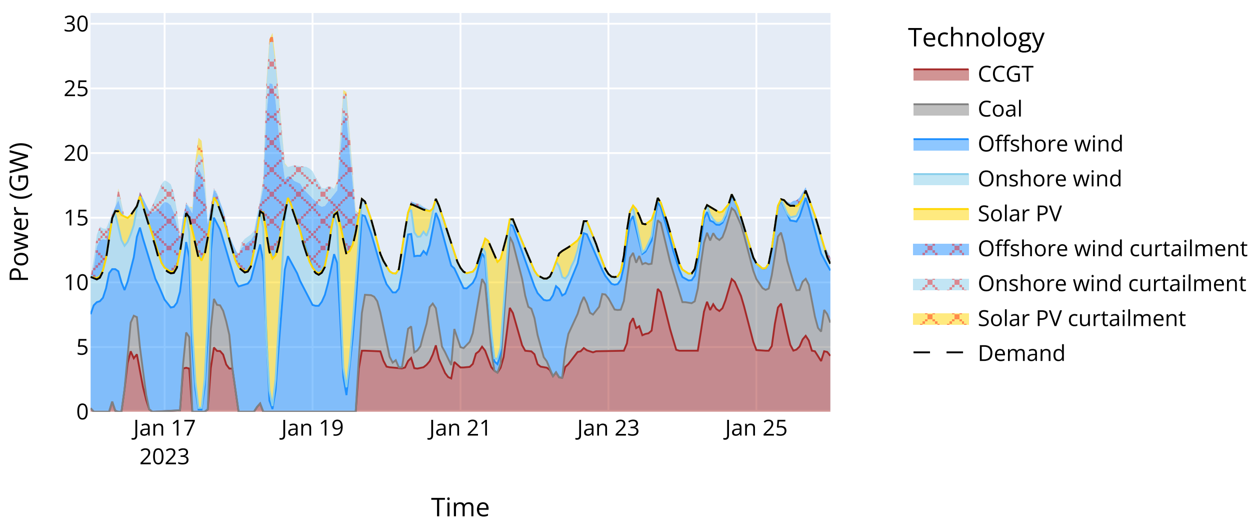

Figure C.17: *Energy Dispatch for 7 days in January with above-average electricity demand, no battery storage scenario with 2023 demand.*

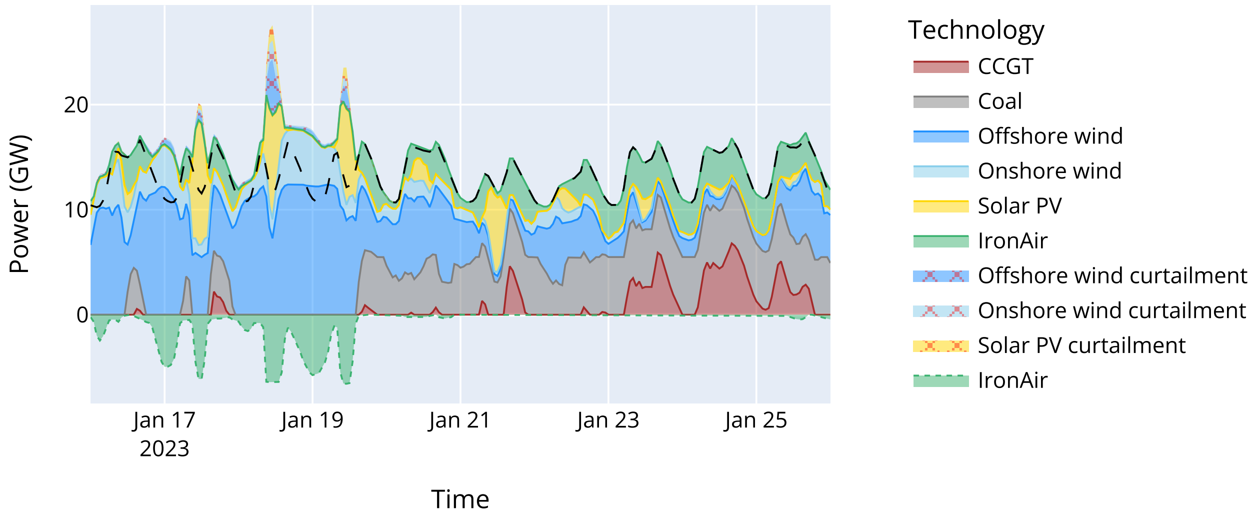

Figure C.18: *Energy Dispatch for 7 days in January with above-average electricity demand, MDES-only scenario with 2023 demand.*

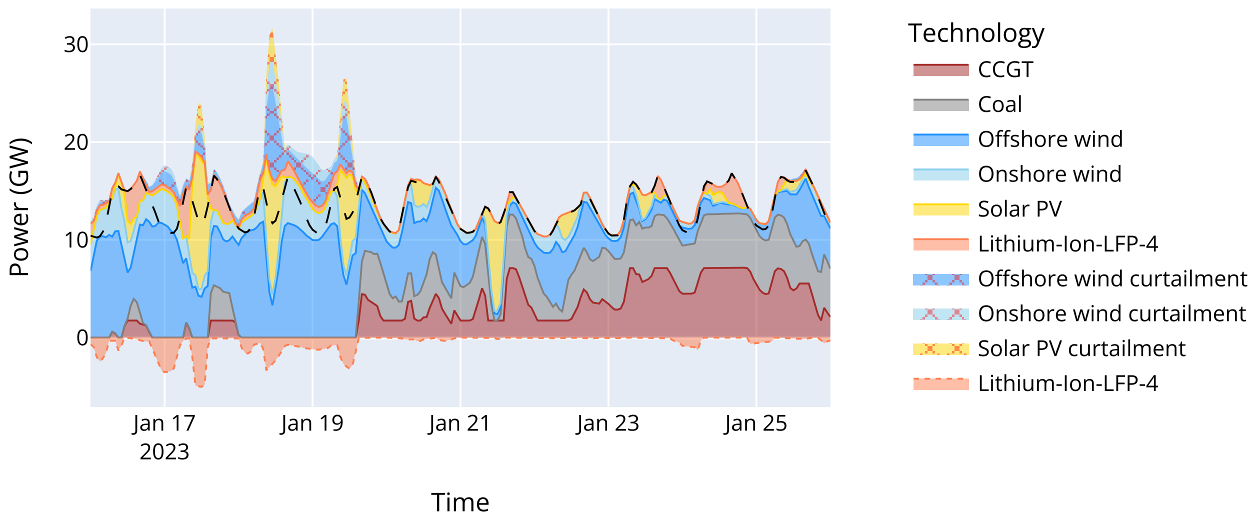

Figure C.19: *Energy Dispatch for 7 days in January with above-average electricity demand, SDES-only scenario with 2023 demand.*

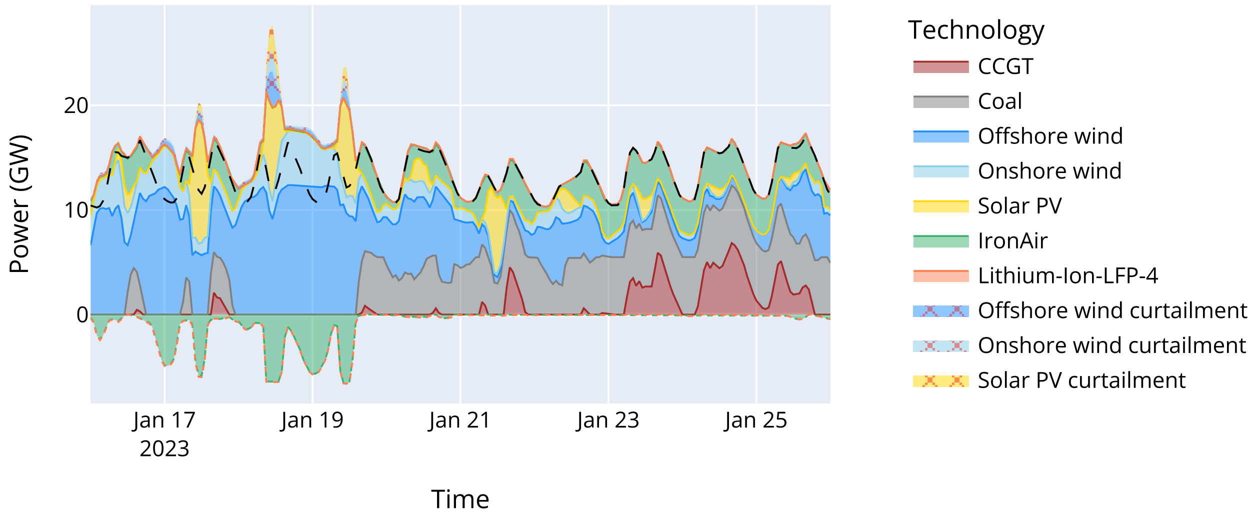

Figure C.20: Energy Dispatch for 7 days in January with above-average electricity demand, both MDES and SDES scenario with 2023 demand.

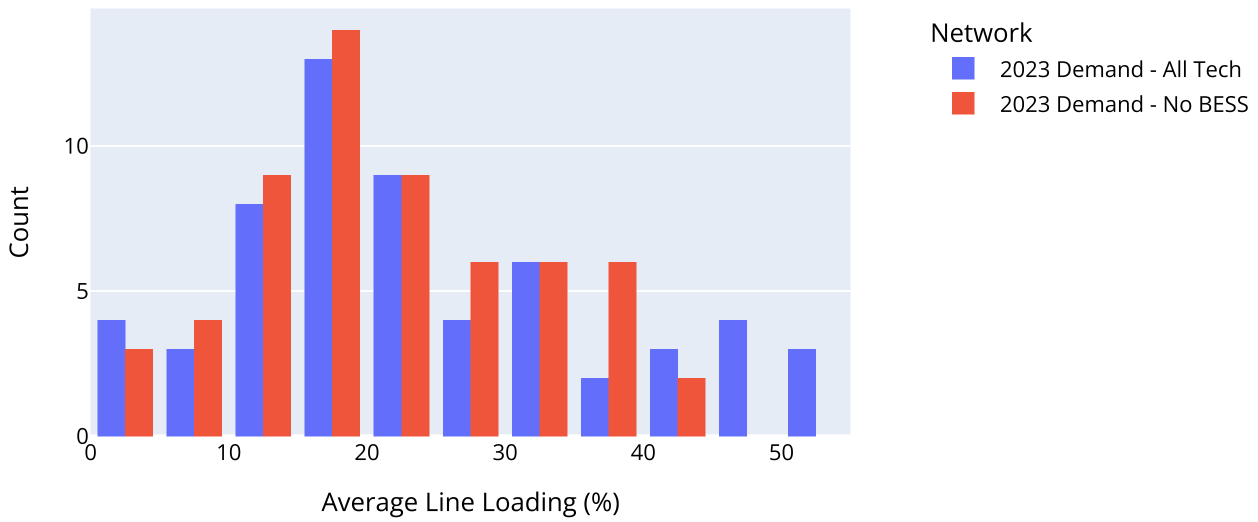

Figure C.21: Histogram of average HVAC line loading across all transmission lines. For each line, its loading is averaged over the simulation period and assigned to the corresponding loading percentage bin.

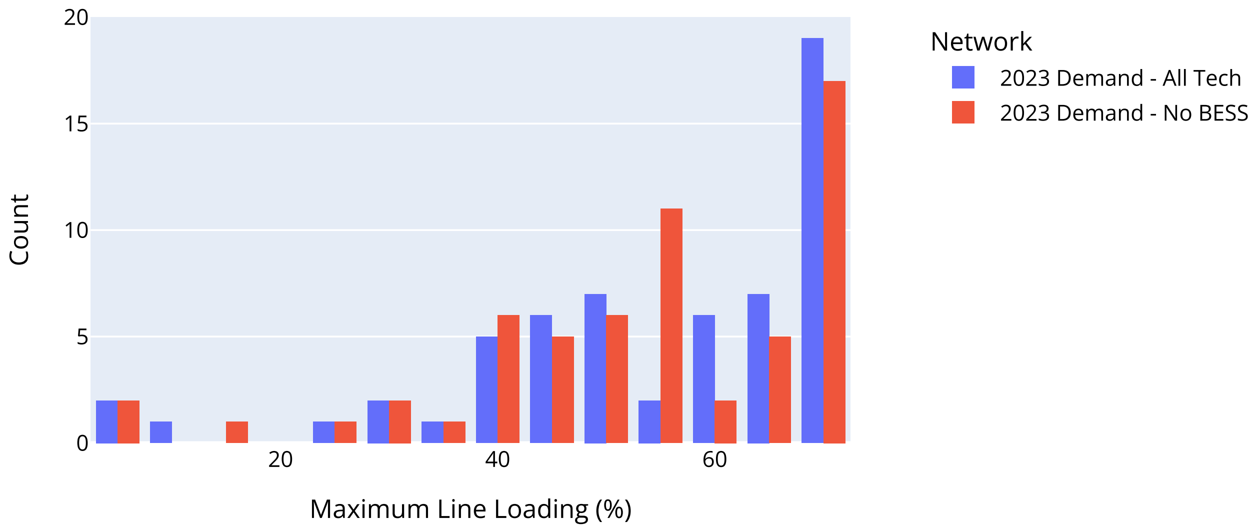

Figure C.22: Histogram of maximum HVAC line loading across all transmission lines. For each line, the highest loading observed over the simulation period is determined and assigned to the corresponding loading percentage bin.

2040 demand scenario

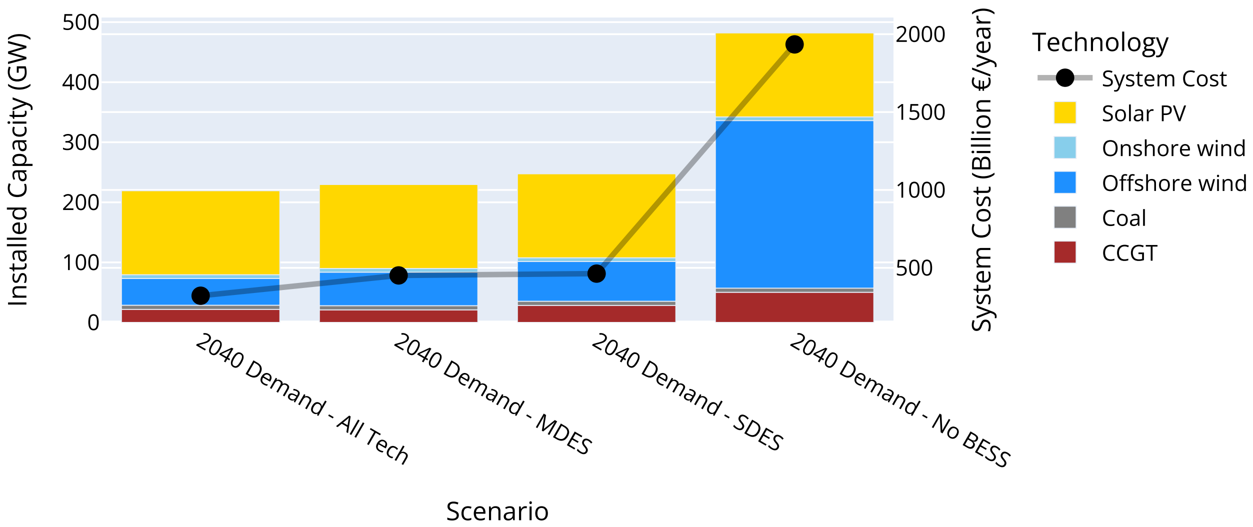

Figure C.23: Optimal generation capacities for 2040 demand scenarios

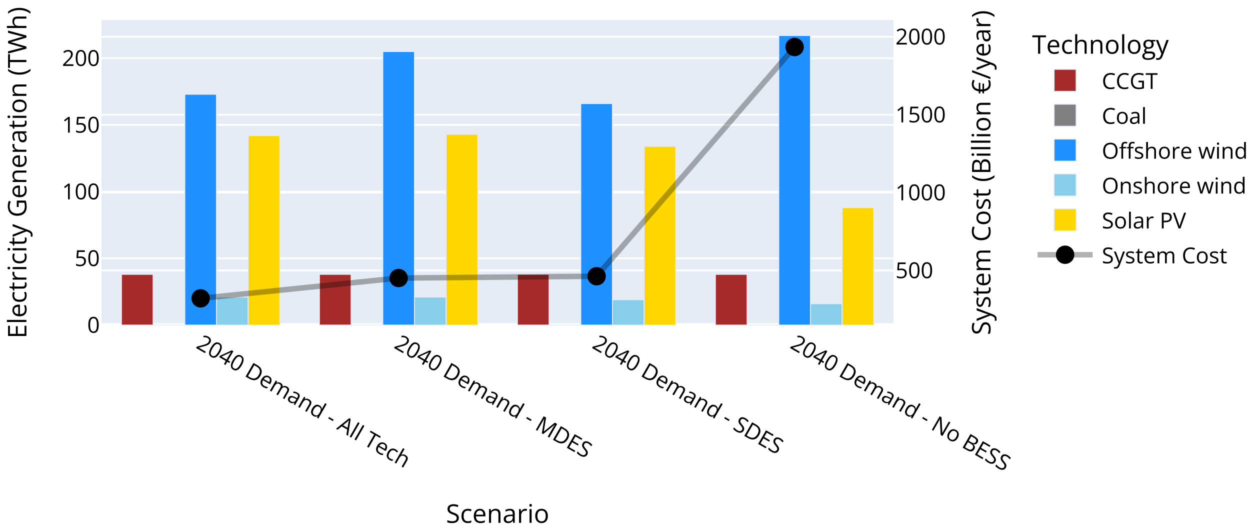

Figure C.24: Total electricity generation for 2040 demand scenarios.

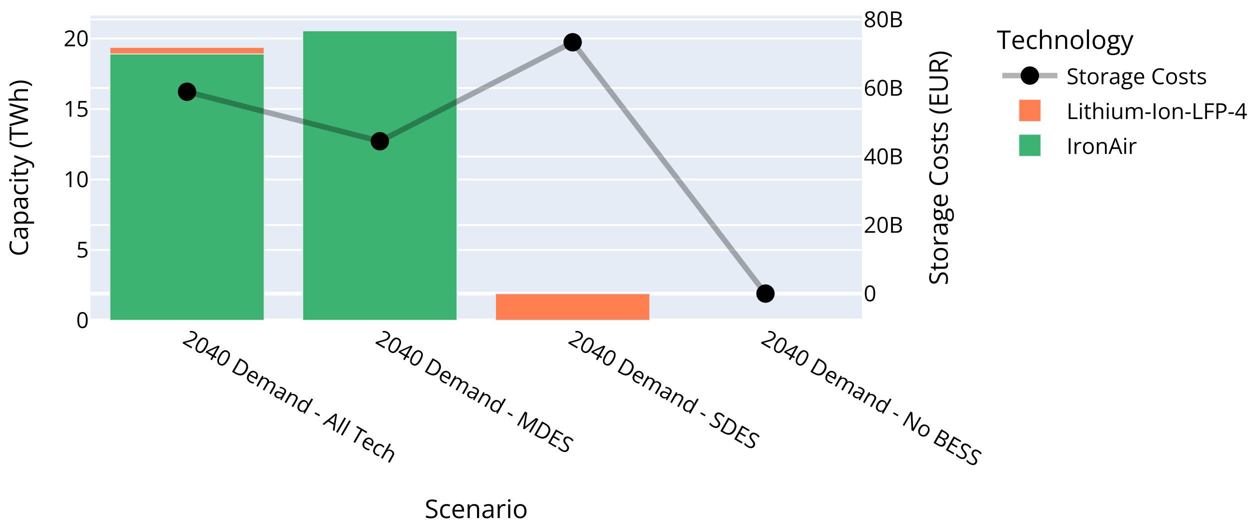

Figure C.25: Optimal storage capacities for 2040 demand scenarios.

Figure C.26: *State of charge of batteries for MDES-only scenario with 2040 demand*

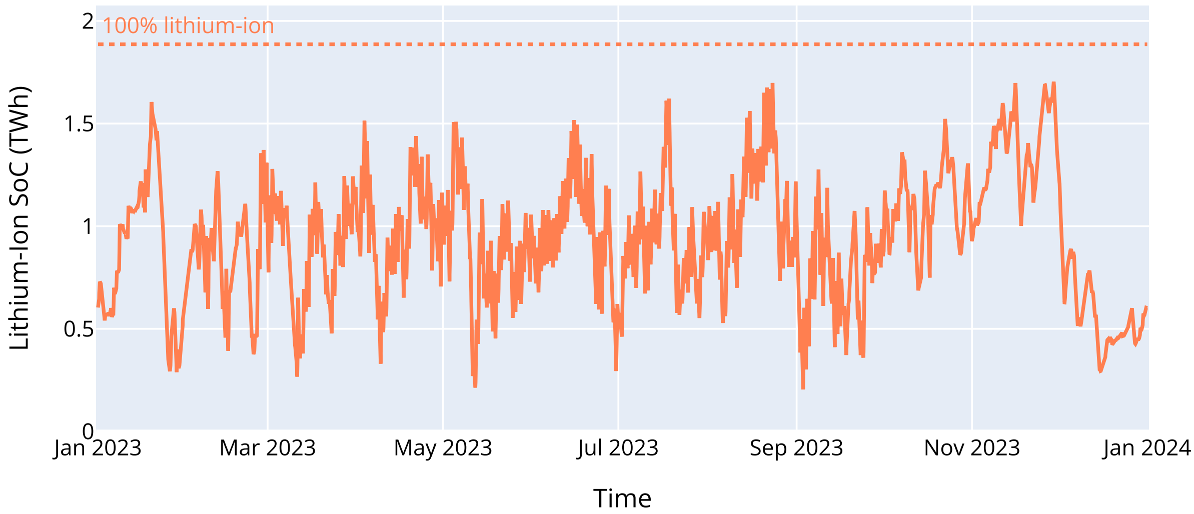

Figure C.27: *State of charge of batteries for SDES-only scenario with 2040 demand*

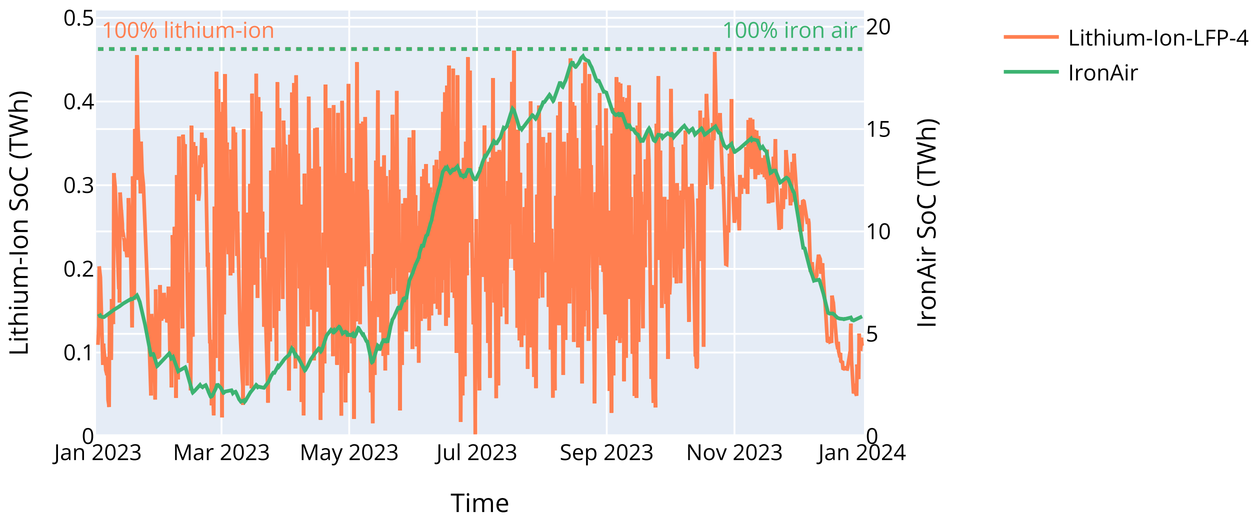

Figure C.28: *State of charge of batteries for a scenario with both SDES and MDES with 2040 demand*

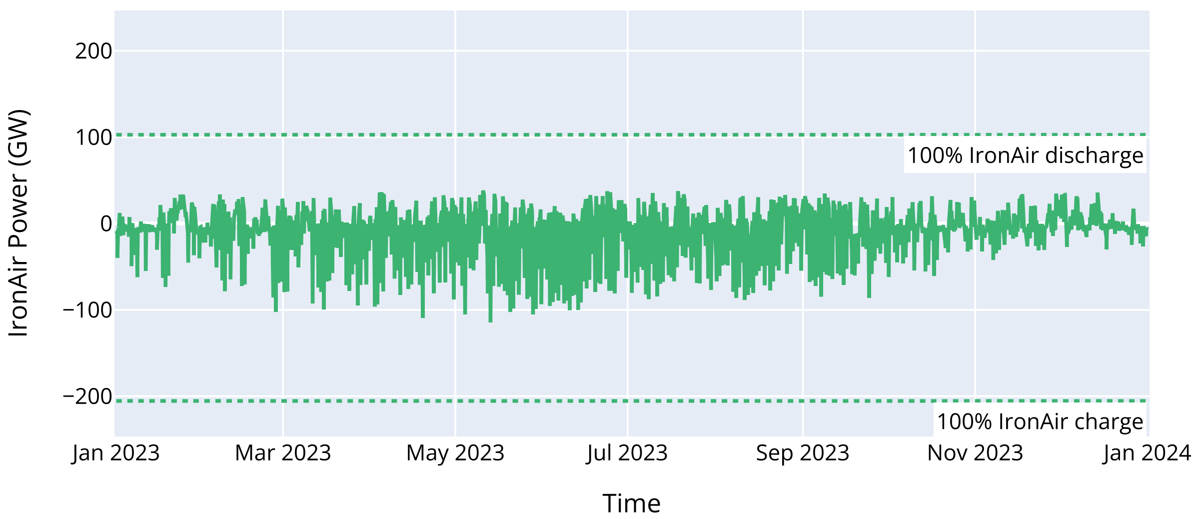

Figure C.29: *Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for MDES-only scenario with 2040 demand.*

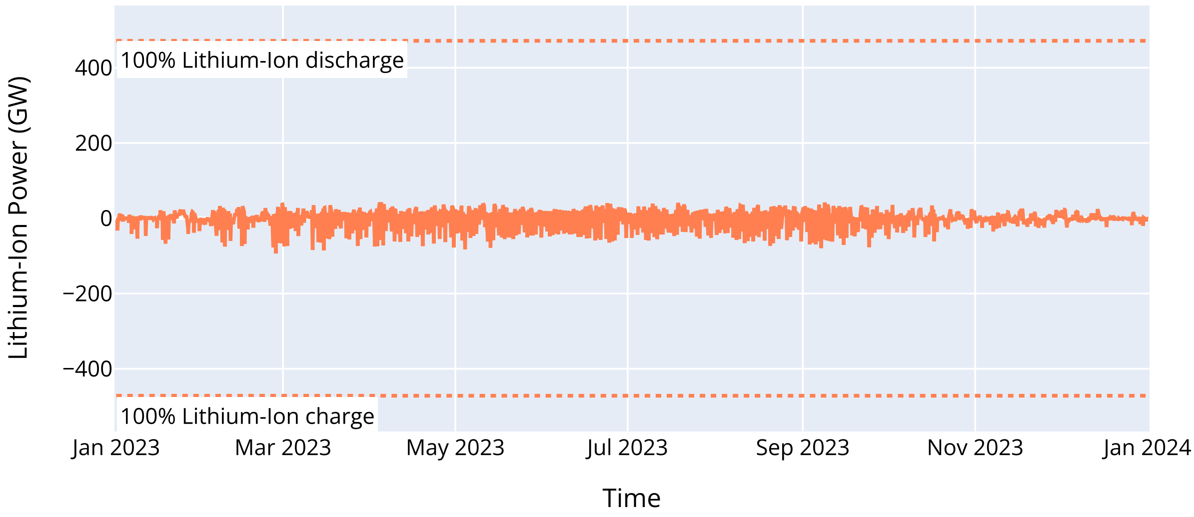

__Figure C.30:__ Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for SDES-only scenario with 2040 demand.

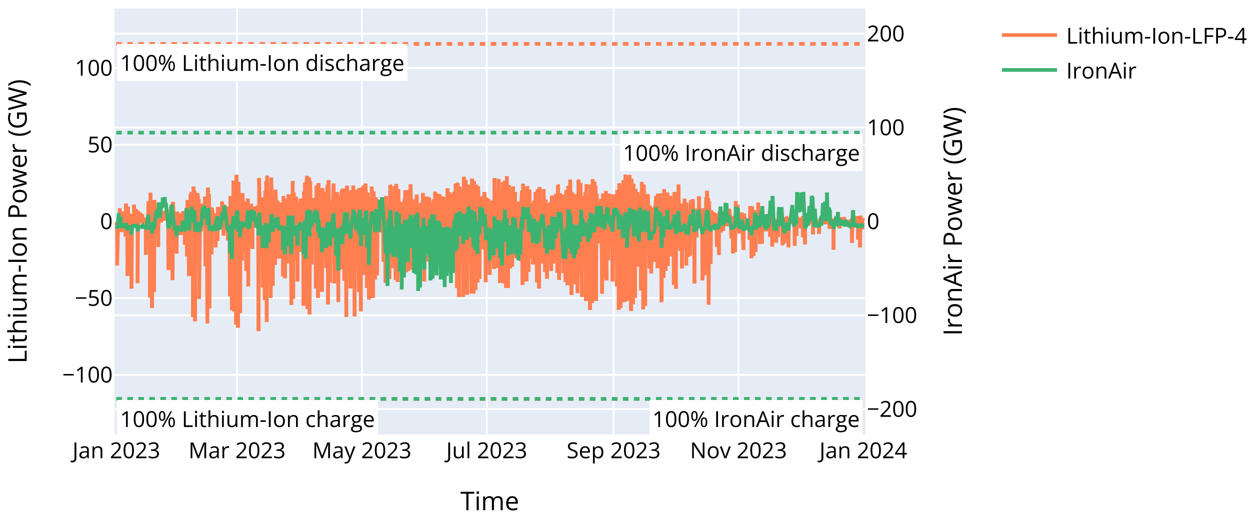

__Figure C.31:__ Battery power discharged to the grid (positive y-axis) and power charged from the grid (negative y-axis) for a scenario with both MDES and SDES with 2040 demand.

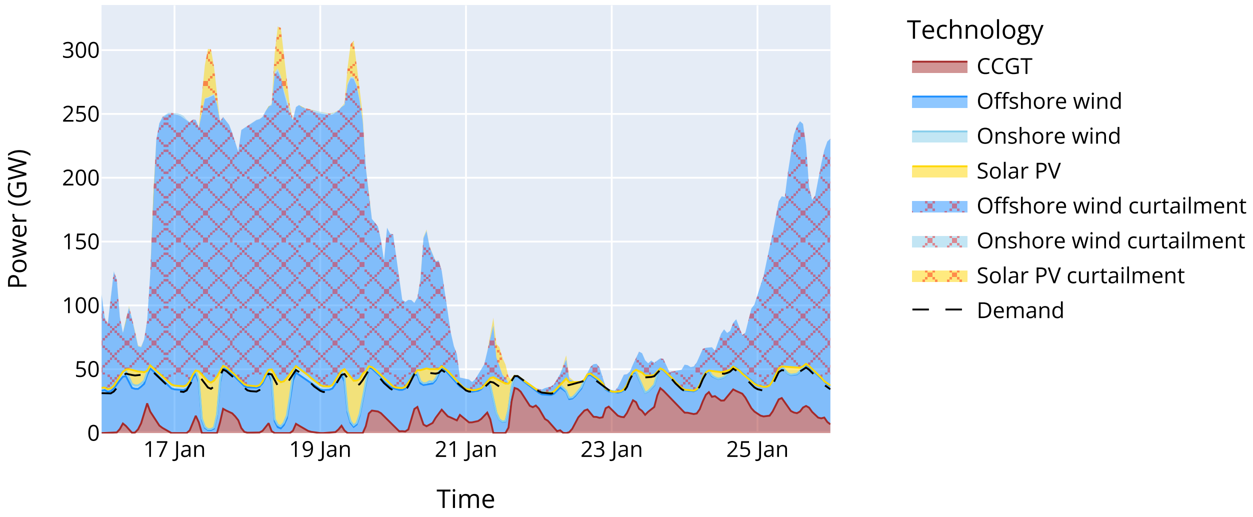

Figure C.32: *Energy Dispatch for 7 days in January with above-average electricity demand, no battery storage scenario with 2040 demand.*

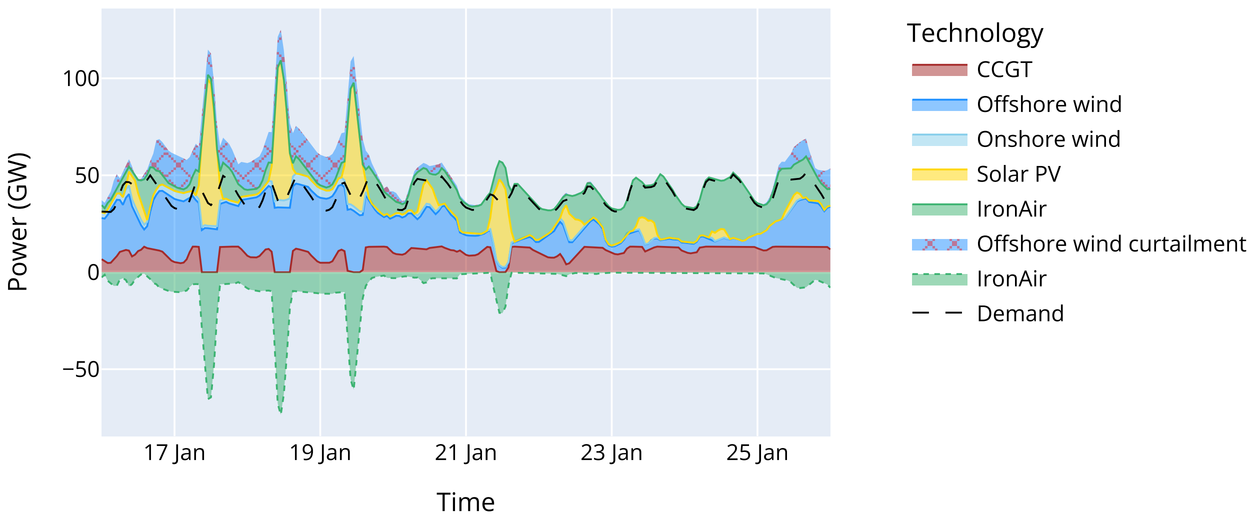

Figure C.33: *Energy Dispatch for 7 days in January with above-average electricity demand, MDES-only scenario with 2040 demand.*

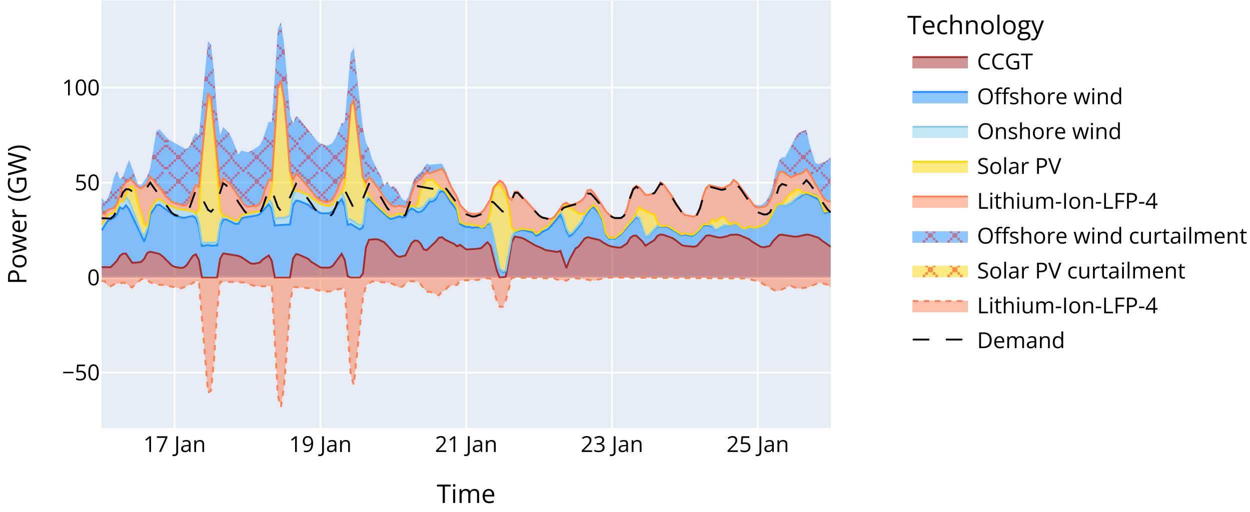

Figure C.34: Energy Dispatch for 7 days in January with above-average electricity demand, SDES-only scenario with 2040 demand.

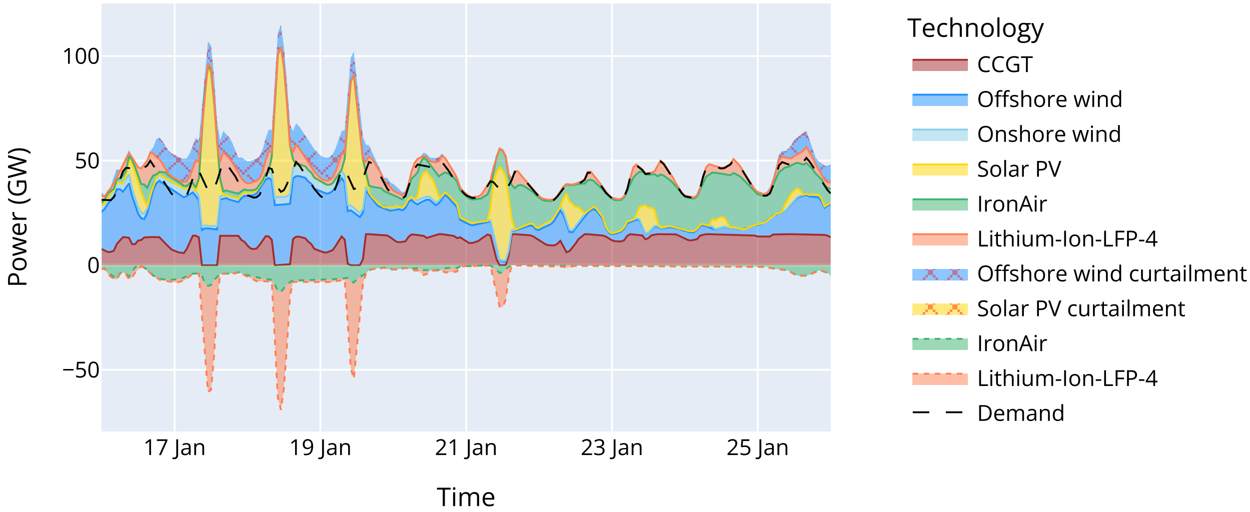

Figure C.35: Energy Dispatch for 7 days in January with above-average electricity demand, both MDES and SDES scenario with 2040 demand.

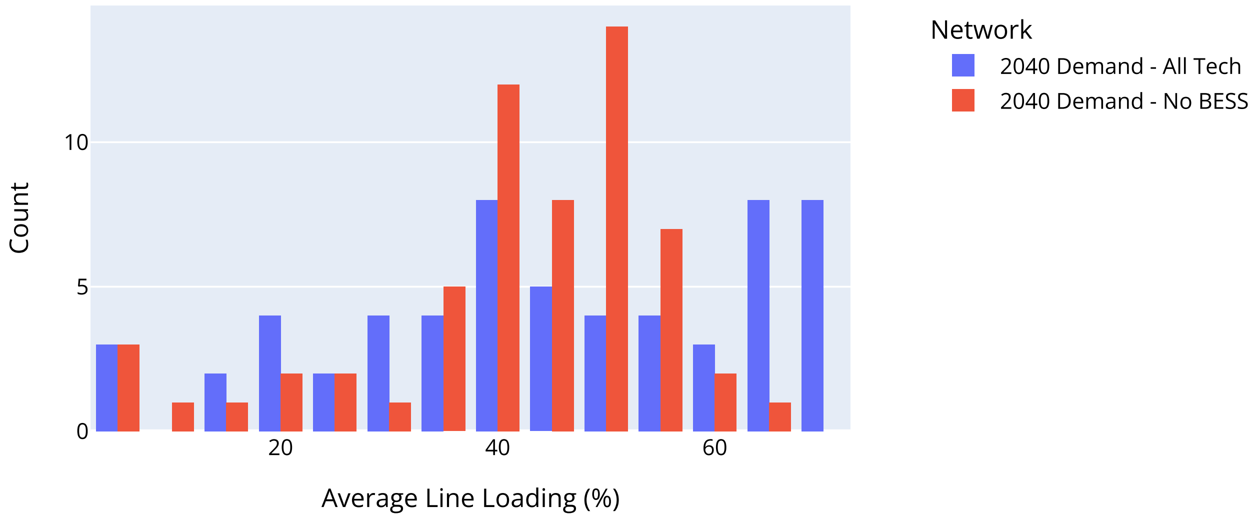

Figure C.36: Histogram of average HVAC line loading across all transmission lines. For each line, its loading is averaged over the simulation period and assigned to the corresponding loading percentage bin.

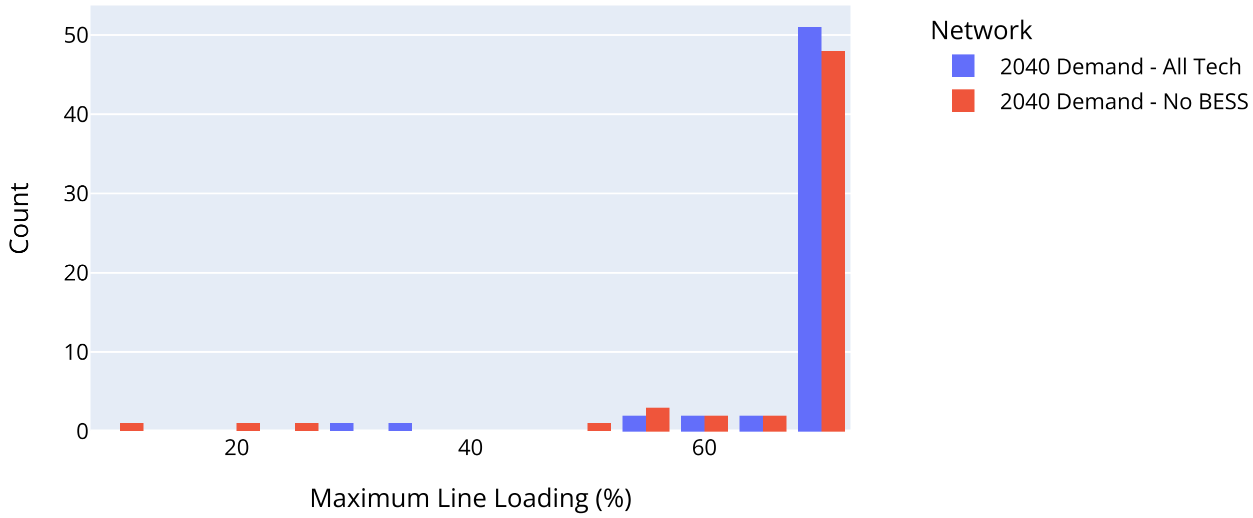

Figure C.37: Histogram of Maximum Line Loading Across All Transmission Lines. For each line, the highest loading observed over the simulation period is determined and assigned to the corresponding loading percentage bin.

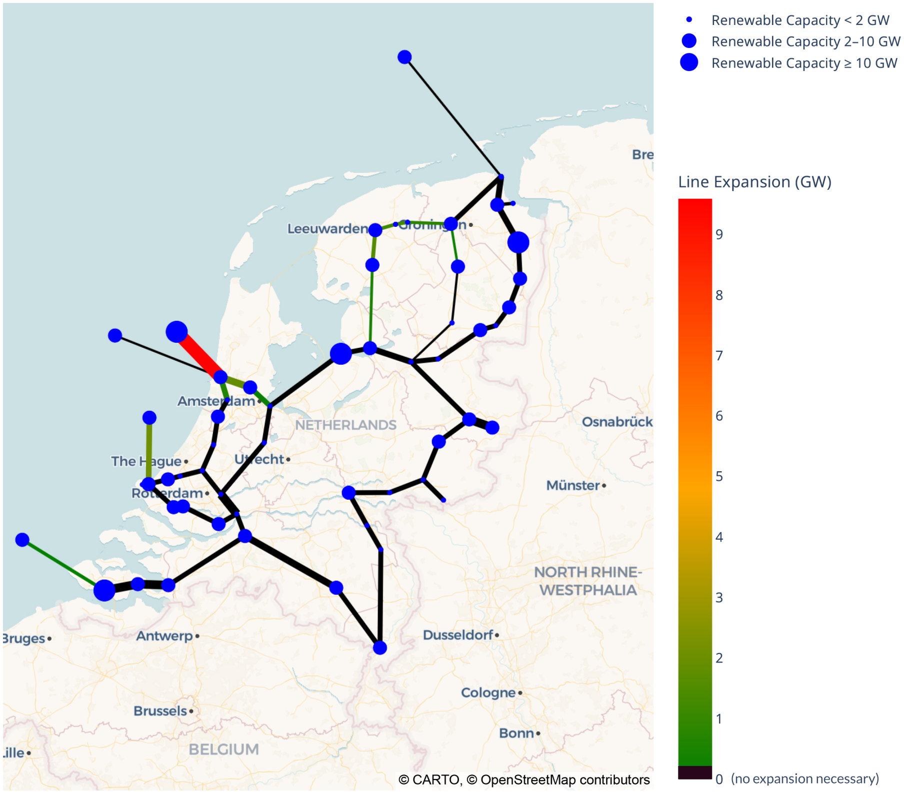

Figure C.38: *Expansion of TSO network for a scenario with only MDES storage. The colour of the line represents the required expansion. The width of the line represents the optimal line capacity.*

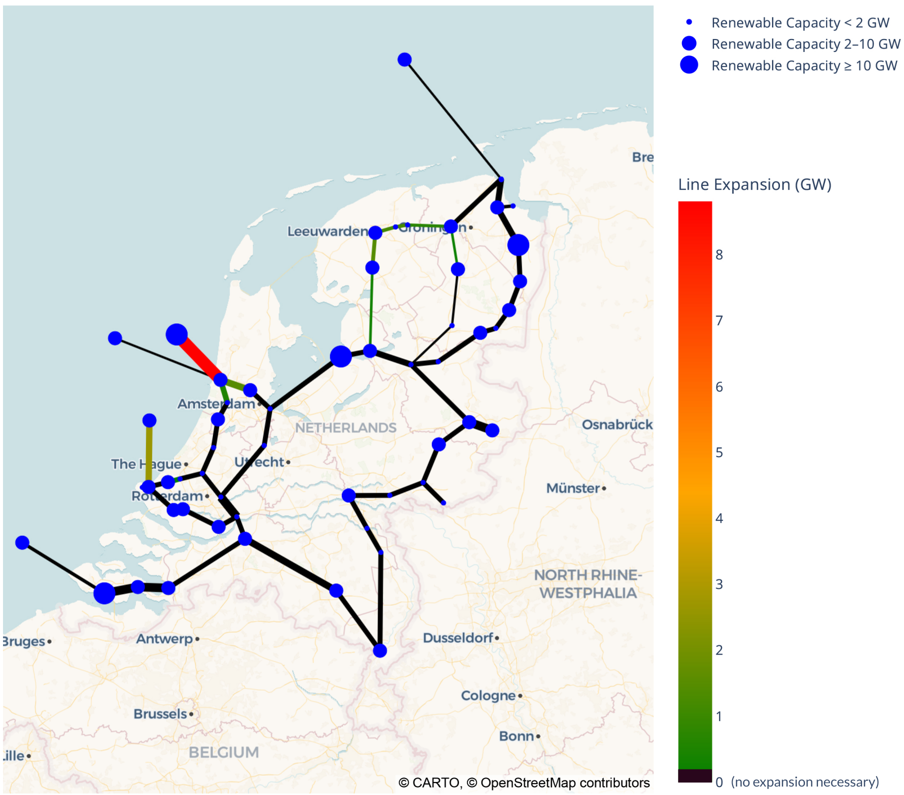

Figure C.39: *Expansion of TSO network for a scenario with only SDES storage. The colour of the line represents the required expansion. The width of the line represents the optimal line capacity.*

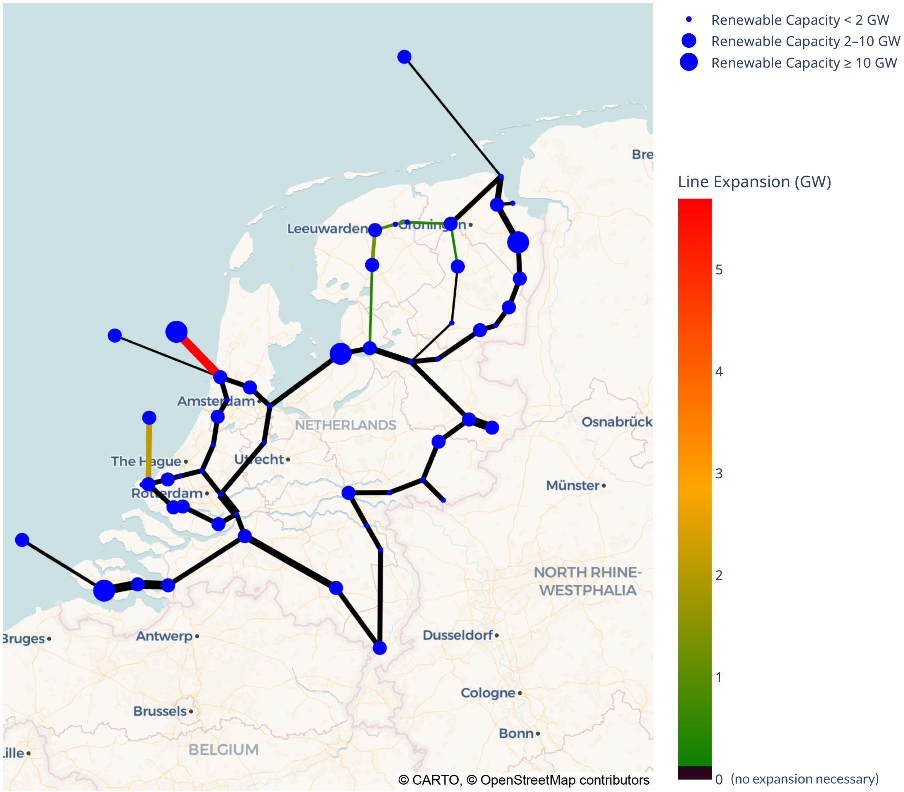

Figure C.40: *Expansion of TSO network for a scenario with both SDES and MDES storage. The colour of the line represents the required expansion. The width of the line represents the optimal line capacity.*

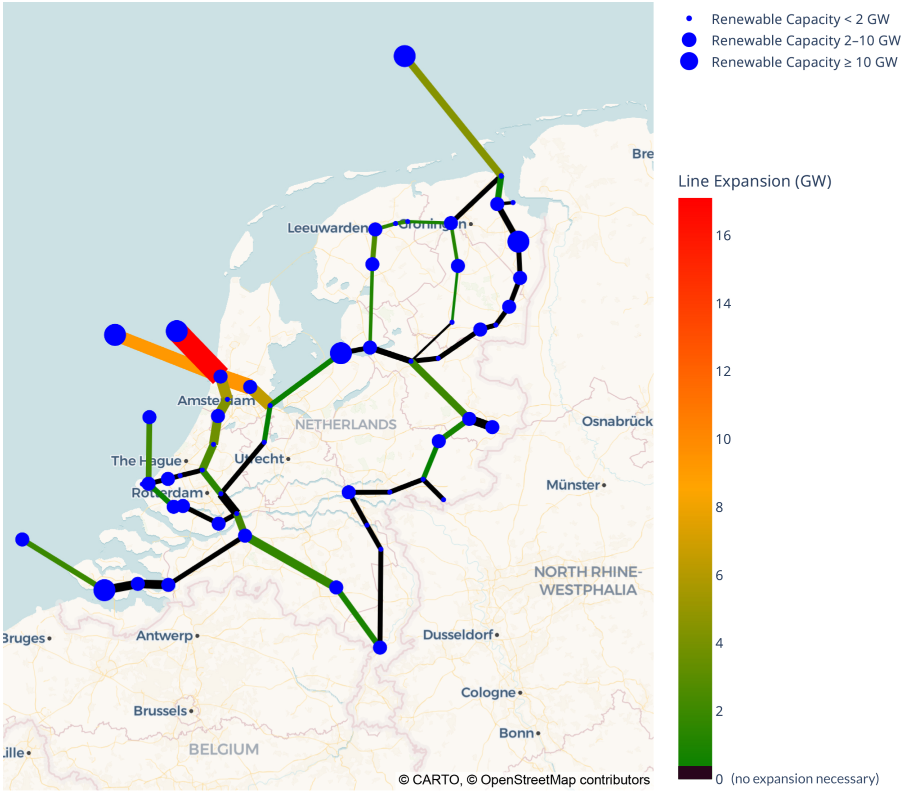

Figure C.41: *Expansion of TSO network for a scenario with no battery storage. The colour of the line represents the required expansion. The width of the line represents the optimal line capacity.*

C.3 Sensitivity Analysis Results

Table C.1: *Sensitivity analysis summary for lithium-ion parameters. Highlighted values indicate deviations of more than 10% from the benchmark scenario.*

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Costs max	19.05	0.43	11.85	324.12
Costs min	18.79	0.51	11.62	317.82
FOM max	19.02	0.43	11.83	323.84
FOM min	18.89	0.47	11.75	320.76
RTE max	18.85	0.47	11.46	316.87
RTE min	18.98	0.45	12.09	325.42
lt max	18.81	0.51	11.64	318.06
lt min	19.01	0.44	11.82	323.19

Table C.2: *Sensitivity analysis summary for iron-air parameters. Highlighted values indicate deviations of more than 10% from the benchmark scenario.*

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Costs max	17.75	0.48	11.84	334.84
Costs min	19.53	0.45	11.71	312.36
FOM max	18.72	0.47	11.78	323.42
FOM min	19.01	0.46	11.74	319.59
RTE max	19.40	0.41	10.99	309.47
RTE min	18.48	0.54	12.52	336.24
lt max	19.12	0.46	11.72	318.47
lt min	18.67	0.47	11.78	324.37

Table C.3: *Sensitivity analysis summary for Grid Costs. Highlighted values indicate deviations of more than 10% from the benchmark scenario.*

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Grid costs max	20.05	0.59	11.14	483.83
Grid costs min	9.68	0.25	16.43	124.97

Table C.4: Sensitivity analysis summary for CO_2 target. Highlighted values indicate deviations of more than 10% from the benchmark scenario.

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
CO_2 target strict	23.52	0.50	15.21	399.27
CO_2 target loose	15.43	0.44	8.32	252.60

Table C.5: Sensitivity analysis summary; addition of Hydrogen Cavern storage. Highlighted values indicate deviations of more than 10% from the benchmark scenario.

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark	18.91	0.46	11.76	320.97
Addition of Hydrogen Cavern Storage	5.34	0.47	12.24	307.12

Table C.6: Sensitivity analysis summary for changes in electricity demand. Highlighted values indicate deviations of more than 10% from the benchmark scenario.

Scenario	Iron-air installed capacity (TWh)	Lithium-ion installed capacity (TWh)	Required grid investment (GW)	Total system cost (Billion €/yr)
Benchmark (Demand - 3x)	18.91	0.46	11.76	320.97
Demand - 1x	0.69	0.00	0.00	6.48
Demand - 1.25x	1.03	0.01	0.00	9.66
Demand - 1.50x	1.25	0.03	0.00	14.04
Demand - 1.75x	1.29	0.06	0.00	19.32
Demand - 2x	1.53	0.09	0.00	25.11
Demand - 2.5x	13.84	0.33	1.07	79.68
Demand - 3.5x	24.79	0.76	35.93	746.55
Demand - 4x	34.26	0.85	54.07	1365.39

D Thesis planning

Activity	Start	Duration	Milestones at the end of activity
Input parameter research	17 feb	3 weeks	Information about future technology costs, renewable penetration levels and costs of grid investment
Modeling and fetching conceptual results	10 mrt	2 weeks	Initial results on impact of SDES and MDES on grid investment deferral, for one scenario
Adapting results based on insights and feedback	24 mrt	3 weeks	Results are conform expectations of supervisors and answer the research questions
Performing sensitivity tests and fetching all final results	21 apr	3 weeks	Impact of SDES and MDES for mutliple scenarios has been analysed
Conducting interviews with TSOs to assess implications	21 apr	4 weeks	Answer to how the findings of this research can be used and which implementation challenges they might face
Reporting	28 apr	3 weeks	
Preparing for defense presentation	2 jun	3 weeks	
Defence	30 jun	1 week	

Figure D.1: List of phases and their associated milestones.

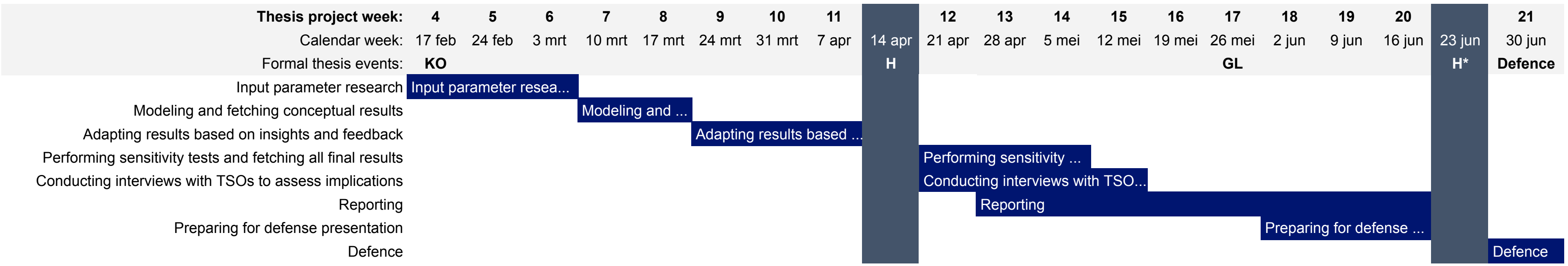

*Figure D.2: Gantt Chart of thesis phases. **Thesis events legend:** KO = kick off, H = holiday, H*= buffer days/ holiday, GL = green light meeting.*

E Disclaimer on the Use of Artificial Intelligence

Several Artificial Intelligence (AI) tools were used during the development of this thesis, while following the guidelines of the TU Delft. AI has been used to:

1. Create Python code to analyse the PyPSA-Eur output and develop figures.
2. Find additional academic sources, yet always as supplement to searches on websites such as Google Scholar and Scopus. AI was used to find sources, but was never the source itself.
3. Rephrase paragraphs.

I consent that I bear full responsibility for the final content of this thesis. AI has never been used as a source, just as a tool, and all AI output has been checked before usage.