Battery systems to support the Dutch regional power networks

A techno-economic analysis of the influence of system location on the value of a battery system for regional network operators

S.C. Slot

Master of Science Thesis

TU Delft Delft University of Technology

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For the degree of Master of Science in Sustainable Energy Technology
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S.C. Slot

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Thesis committee:
Dr.ir. R.A. Hakvoort - TU Delft
Prof. Dr. F.M. Mulder - TU Delft
Ir. Thijs Scholten - CE Delft
Ir. Frans Rooijers - CE Delft

Faculty of Electrical Engineering, Mathematics and Computer Science (EEMCS) · Delft University of Technology

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Executive Summary

Around the world, power systems are transforming rapidly. To reduce CO_2 emissions and halt climate change, the largest share of electricity will soon have to be generated by carbon-free sources. Wind- and solar-powered generation is set to become dominant both globally and in the Netherlands. However, integrating additional renewable generation capacity into existing power networks presents a challenge to network operators. Wind and solar generation are characterised by increased variability, causing higher peak loads on power networks. Moreover, the energy transition also increases demand loads through electrification. Combined, these effects are causing power networks in the Netherlands to become congested, limiting the possibilities for integrating more renewable generation capacity into the networks.

There are two main ways to reduce congestion: increasing the network capacity or decreasing the network load. The network capacity can be increased by upgrading the grid, which is often expensive and time-consuming. The load on the network can be decreased by curtailment– discarding the excess generation in moments of overload, often resulting in costs for network operators. Another solution would be to shift the transport of excess generation to a moment with sufficient network capacity. Battery systems could provide this function, as they are well-equipped to storing electricity for a short (<24 hours) period.

This thesis studies how batteries could provide a solution for integrating additional renewable generation into congested regional networks in the Netherlands. There are different ways to integrate a battery system into the network, and the value the battery system can provide to the network will likely depend on how and where it is integrated. This integration can be defined by two key characteristics: the physical location of the battery's connection to the regional network and the type of renewable generator connected to the battery system and network. The combination of the connection location and the connected renewable generator is called 'system location' in this study, because these combinations of connection and renewable generator are elements that can be found in many power systems.

To determine where batteries could provide the most value, the influence of system location on the value a battery system can pose to the regional network operator is researched. The viewpoint of the regional network operator is used for the valuation of the system because the operator is the party that will decide which solution to implement when integrating additional

renewable generation. To analyse the influence of system location on the value of the battery system, eight different system locations are studied, with batteries connected to the network either at the site of the renewable generator or at a regional HV/MV substation, combined with four different additional renewable generation scenarios.

With assistance from Liander (a DSO), a case study is formulated around substation Waalsprong, which is at risk for congestion in the near future. Two different models are designed to dispatch the battery systems. The first is developed for a battery sized to resolve all projected congestion on the substation. Results demonstrate that to fully solve the projected congestion, large (>25 MWh) volumes of storage capacity are necessary for all system locations. To improve on this large and inefficiently used battery system, a second dispatching model is developed. This model combines battery operations with curtailment and minimises curtailment costs for the network operator over an entire year. The model uses predicted curtailment costs, based on EPEX prices and subsidies. For the case of Waalsprong, the combined battery and curtailment model achieves its goals: curtailment costs are reduced between 65-80%, depending on the system location. The volume of curtailed electricity is reduced by at least 60% in every scenario. Additionally, connecting the system at the generator site has resulted in higher battery revenues from charging and discharging.

To determine the economic feasibility of the battery systems, a cost-benefit analysis is performed from the perspective of the network operator. Four solutions for integrating additional renewable generation at substation Waalsprong are compared: grid upgrades, curtailment, the large battery solving all congestion and the battery + curtailment system. Results indicate that curtailment is always the least-cost option for Waalsprong, but it should be noted that curtailment is only allowed on a temporary basis under current regulations. Of the other solutions, the battery + curtailment system results in fewer costs for the network operator for all solar generation scenarios. In contrast, for wind or combined wind/solar generation, grid upgrades result in fewer costs. The connection location of the battery system has a limited impact: for the solar scenarios, connecting the system at the generator is slightly advantageous.

To put this research into a broader perspective, an analysis was made of stakeholders, regulations and barriers connected to battery systems in the Netherlands. Current regulations ban network operators from owning and operating batteries. Therefore, private parties would have to provide this service to network operators. This shed new light on the influence of system location on battery value: due to high transportation and connection tariffs, private parties operating a battery will always do so at a generator location.

Based on the overall research findings, recommendations to the network operator and other stakeholders can be made. First, both the regulator and the network operators should be open to other solutions for congested network areas: this research has shown that for Waalsprong, a battery and curtailment system could result in fewer costs than a network upgrade in some scenarios. Second, a regional tendering system for requesting flexible capacity through long-term contracts should be set up, in which battery operators could participate to deliver flexible capacity to DSOs. Third, DSOs should also consider battery systems as a short-term option, while waiting for network upgrades, as a large share of the Dutch network will need to be upgraded in the coming decades. Finally, the Dutch electricity tariffs are in need of a revision: current tariffs create an unlevel playing field for battery systems. This could be corrected by exempting battery systems from some parts of the transportation tariff.

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Glossary

List of Acronyms

CBA	Cost-Benefit Analysis
DSO	Distribution System Operator
FCR	Frequency Containment Reserve
HV	High-Voltage
MV	Medium-Voltage
LV	Low-Voltage
Li-Ion	Lithium Ion
TSO	Transmission System Operator
SoC	State of Charge
VRES	Variable Renewable Energy Sources

Preface

This thesis is the result of months of hard but enjoyable work, ranging from weeks of modelling to stakeholder interviews to diving deep into laws and regulations. Going in, I knew next to nothing about battery systems, and I had some but limited knowledge of the Dutch power system. Learning about both topics has been a fascinating journey. Over the course of this thesis, I have become increasingly convinced of the substantial role batteries will play in our future power systems - a fact of which I was sceptical when starting out.

Of course, 2021 was not a regular year. For my thesis, COVID has been both a blessing and a curse. There were fewer distracting elements, which sped up the process, but working on an individual project from home was challenging and frustrating at times.

Luckily, I had a great support team. To my first supervisor from Delft University of Technology, Rudi Hakvoort, thank you for your valuable feedback, guidance and advice along the way. Although I have enjoyed your constantly changing zoom-backgrounds, and I'm happy we got to meet in person at least once before my graduation. To my supervisor from CE Delft, Thijs Scholten, thank you for your extensive support. Your sound advice on my research approach and the structuring of the problem researched in this thesis have been invaluable. I would also like to thank Frans Rooijers and Fokko Mulder for their feedback and interesting input during our shared discussions - getting to know both your visions on the Dutch energy system has been inspirational.

This thesis marks the end of my time at Delft University of Technology, which has been an incredible chapter of my life. During my Masters in Sustainable Energy Technology, I've managed to find the topic I am most passionate about. I aim to continue to work in this exciting field, and I hope I will be able to make a meaningful contribution to solving the challenges of the energy transition.

Chapter 1

Introduction

Last August, the sixth Intergovernmental Panel on Climate Change (IPCC) report was released, stating, "It is unequivocal that human influence has warmed the atmosphere, ocean and land." (IPCC, 2021). To limit global warming to 1.5 - 2 °C, greenhouse gas emissions must be reduced drastically in the coming decades. One of the first priorities in reducing greenhouse gas emissions is the decarbonisation of global power systems. As shown in figure 1-1, the power sector has historically been responsible for the largest share of global CO_2 emissions, and its emissions are still rising. In 2018, electricity and heat production accounted for 42% of global CO_2 emissions (International Energy Agency, 2019).

Carbon-free ways of generating electricity are on the rise: large-scale solar and wind power generation plants are increasingly becoming a part of our landscape and power system. Many countries and regions have set targets for reducing emissions and increasing renewable energy production. For example, the European Union has set ambitious goals for 2030: at least a 40% reduction in greenhouse gas emissions[1] and at least 30% of consumed energy coming from renewable sources (The European Parliament and the Council of the European Union, 2019a). Last year marked a turning point: 2020 was the first year during which carbon-free electricity generation overtook fossil-fired generation in Europe. Carbon-free sources generated 38% of Europe's electricity, and fossil-fired generation only 37% (Buck, Redl, Hein, & Jones, 2020). This increase in carbon-free electricity was mainly caused by significant increases in wind and solar generation: wind generation grew by 9% and solar generation by 15% in Europe in 2020 (Buck et al., 2020).

As global concerns about CO_2 emissions and climate change grew, so did concerns in the Netherlands. In 2019, the climate agreement was finalised, including an ambitious renewable electricity generation goal: in 2030, 70% of all electricity will be supplied by renewable energy sources (Rijksoverheid, 2019a). Considering that in 2019 only 13% of electricity was generated by solar and wind, it is clear that the Netherlands still has a long way to go before reaching its 2030 goal (Centraal Bureau voor Statistiek, 2021). The climate agreement plans to reach 70% by realising at least 49 TWh of annual offshore wind electricity generation

[1] From 1990 levels, this number is likely to be raised to 55%.

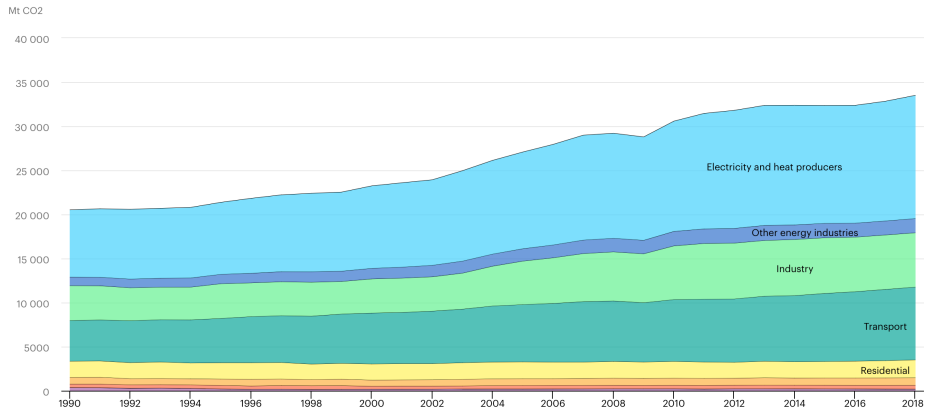


Figure 1-1: Global CO_2 emissions by sector, 1990-2018 (International Energy Agency, 2019)

and 35 TWh of onshore renewable electricity generation (likely a combination of wind and solar PV) (Rijksoverheid, 2019a). This overhaul of the Dutch power system is not without challenges: unfortunately, integrating large shares of solar and wind generation into existing electricity networks is not a simple task.

1-0-1 Challenges of Variable Renewable Energy Sources

Electricity generation from solar and wind is highly dependent on weather conditions and is thus variable in time. As a result, these electricity sources are often called Variable Renewable Energy Sources (VRES). The International Energy Agency estimates that globally, VRES will make up 90% of the net increase in power capacity through 2025. Of these renewable power additions, 60% of capacity will come from solar PV and 30% from wind (IEA, 2020b).

Although the rise of solar and wind-powered electricity generation is crucial in reducing greenhouse gas emissions, replacing traditional electricity sources with these new sources is not an easy task. The variable and uncontrollable nature of VRES generation poses a stark contrast to traditional coal-fired generators that are relatively easy to turn on, shut off or run at a desired capacity.

Integrating a higher share of VRES into the current power systems is challenging in multiple ways. A distinct feature of power systems is that historically, large amounts of storage have not been available. Because of this, supply and demand must always be matched almost instantaneously (Lund, Lindgren, Mikkola, & Salpakari, 2015). With a rising share of uncontrollable, intermittent power supply, it becomes harder to balance supply and demand, which is also volatile (Brunner, Deac, Braun, & Zöphel, 2020).

Another factor complicating the integration of VRES in power systems is the availability of network capacity. The variable output from solar and wind generation puts a significant strain on existing power networks. Traditional generators supplied a steady output, and power networks were optimised to ensure security of supply. However, increasing power network capacity is expensive, so networks were designed to carry only the capacity generated. In contrast, VRES generation is marked by its increased peaks of power production. These peaks may reach many times the average power capacity of a generation unit, and traditional

power networks are often not equipped to handle such loads. Additionally, power systems have to carry the load of increased electrification: to reduce greenhouse gas emissions, electricity consumption will increase across sectors. Examples of this include the rise of electric vehicles and electric heating.

These complications are becoming more and more visible in the Dutch power system. In figure 1-2, areas with limited transport capacity available for generators are indicated in red and orange. This map clearly shows that no new large-scale generators can be integrated into power networks in large areas of the Netherlands (such as Friesland and Flevoland). The red areas are typical areas where electricity generators tend to connect new solar or wind generators: the areas are not too densely populated, and land prices are lower than in urban areas. However, because of this low population density, the original regional networks in these areas were not constructed to withstand large loads. This results in congestion: there is insufficient network capacity available to transport all loads.

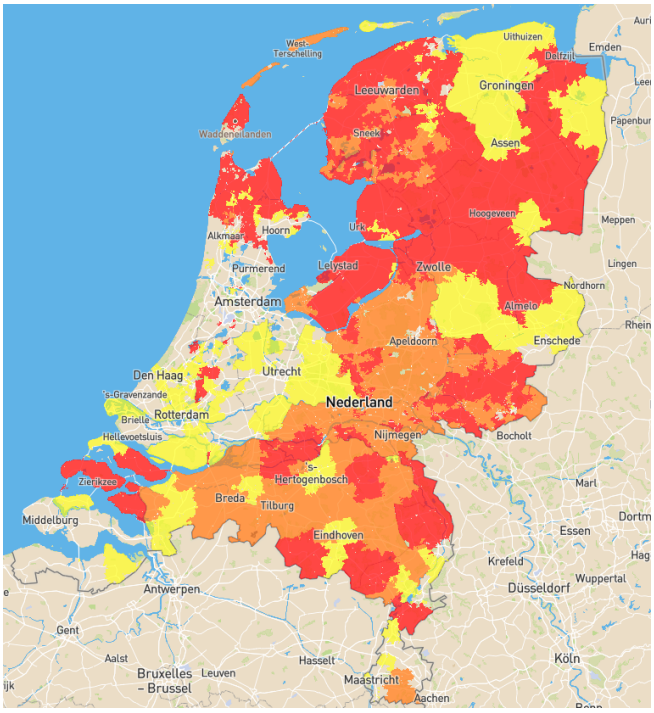


Figure 1-2: Map of available network capacity for large-scale generators in the Netherlands. Red areas: structural congestion, no new transport capacity available. Orange areas: projected structural congestion. Yellow areas: risk of limited transport capacity. Areas without colour: no limitations in transport capacity (yet) (Netbeheer Nederland, 2021).

There are two main ways to solve the problem of congestion: increasing the network capacity or decreasing the network load. The network capacity can be increased by upgrading the grid, which is often expensive and time-consuming. The load on the network can be decreased by curtailment - discarding the excess generation in moments of overload, resulting in curtailment costs which are often carried by the network operators. Another solution would be to shift the transport of the excess of generated electricity to a moment with sufficient network capacity. Energy storage systems could provide this function.

1-0-2 Energy storage systems

In essence, energy storage is nothing more than the shifting of electricity supply in time by converting it to a form in which it can be saved (Lund et al., 2015). Because of the time-shift nature of storage systems, one of the most important features of a storage solution is the timescale it is most suitable for. Figure 1-3 gives an overview of storage technologies classified by their capacity and discharge time.

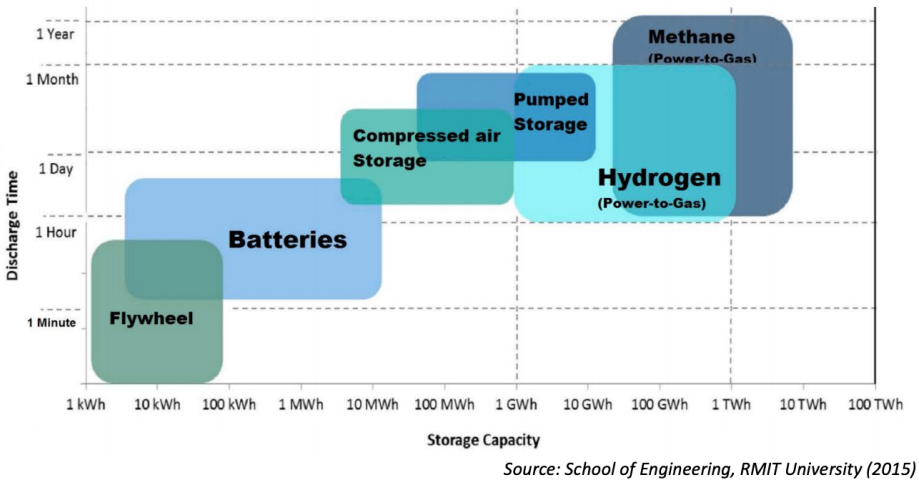


Figure 1-3: Energy storage systems classified by their capacity and discharge time (Zobaa et al., 2018)

Currently, the most common energy storage systems are pumped hydro storage systems: in 2017, these made up 96% of the global electricity storage capacity (IRENA, 2017a). However, interest in battery energy storage systems is rising. In 2019, batteries accounted for 88% of all patenting activity in the electricity storage space (IEA, 2020a). The International Renewable Energy Agency (IRENA) and the International Energy Association (IEA) both expect battery systems to become an essential element in future power systems, mainly because the timescale they operate on is optimal for solving short-term ($<$ 1 day) capacity and balance issues in power networks (IRENA, 2017a), (International Energy Agency, 2018).

Battery systems can solve both the balancing and network capacity issues as follows: firstly, they can store energy during high-supply, low-demand times, supporting the power system balance. This function is depicted in the lower part of figure 1-4. Secondly, battery systems can relieve some of the strain VRES with high capacity peaks put on power networks by shaving the peaks of demand and supply and thus lowering the network capacity required. This function is depicted in the upper part of figure 1-4. In recent years, examples of battery systems integrated in power grids to perform these two functions have steadily grown.

Energy storage systems in the Netherlands

Over the past years, hydrogen has attracted attention as a potential technology for long-term, seasonal storage in the Netherlands. As a result, multiple demonstration projects are currently being developed (De Laat, 2020). However, besides a solution for seasonal fluctuations in

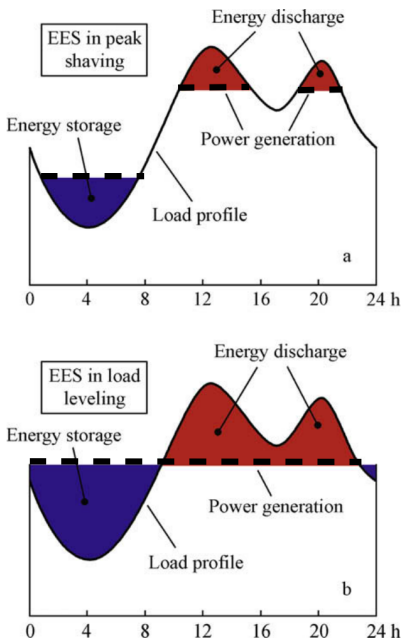


Figure 1-4: Load profile of a large-scale electricity storage system in two modes: (a) Battery system in Peak Shaving; (b) Battery system in load levelling. The dashed black line is the new load, including battery operation. Adapted from (Chen et al., 2009).

supply and demand, the Dutch power system will also need a solution for daily balancing and to reduce peak loads on the grid. Battery systems could provide these functions. Batteries are not yet a fixture in the Dutch power landscape, but the necessity for battery energy storage is often discussed. In "Grid for the Future", Dutch Distribution System Operators (DSOs) sketch multiple scenarios for the energy transition in the Netherlands (Rooijers & Afman, 2017). They expect between 2-60 GW of battery electricity storage to be connected to the grid in 2050, depending on policymakers' choices.

Currently, the largest battery in the Netherlands is a 12 MW battery situated near Lelystad, which provides balancing services to the national network (GIGA Storage, 2019). However, there are no examples of battery systems to reduce regional network congestion (yet). As described in (Zobaa et al., 2018), 'Storage has the greatest value in regions where low price off-peak energy is accessible, and the system is operating close to technical limits'. According to this, storage systems will carry a high value in some regions of the Netherlands. Electricity prices are decreasing during moments of high VRES generation and negative electricity prices have occurred a few times over the past three years (TenneT, 2019). Additionally, figure 1-2 clearly shows that in large parts of the Netherlands, regional power networks are pushing their technical limits. Battery systems could potentially be of great value for (regional) networks in reducing congestion, and integrating additional renewable generation.

1-0-3 Problem statement & research question

To explore the opportunities for battery storage systems in regional networks in the Netherlands, this thesis studies the ways in which battery systems could provide a solution for integrating additional renewable energy sources into congested regional networks in the Netherlands. To maximise the benefits battery systems can provide for the future Dutch (regional) electricity system, it is crucial to know both at which points in the network opportunities are present for battery system integration and with which types of renewable generation battery systems combine best. Research into the combination of these elements, from this point forward called 'system locations', will provide insight into how much value battery systems can deliver to the network and the network operator. This thesis aims to provide insight into the different system locations at which battery energy storage systems can be integrated into the Dutch regional power system by answering the following question:

How does the system location of a battery energy storage system for grid support influence the value such a system can provide to the regional Dutch power network in 2030?

1-1 Research approach

Looking at the research question, the main component of the research is determining the associated costs and benefits of a technological solution to a societal problem. The research question can roughly be divided into two parts: determining the effect a battery system has on the considered power system and then analysing the costs and benefits associated with this effect. A review of previous research shows that both approaches are often used when analysing similar systems (Idlbi et al., 2016), (Li et al., 2016), (Mateo, Reneses, Rodriguez-Calvo, Frías, & Sánchez, 2016).

The approach chosen to answer the research question is two-fold: first, a modelling approach is used, to determine the effects of varying battery system location on the regional power grids. Second, a cost-benefit analysis is performed, to see how varying the location of the battery influences the value the battery system adds to the grid. These activities are all part of different sub-questions; the next section will propose four sub-questions that will need to be answered to formulate an answer to the main research question. Then, a research approach to answer all questions is presented. Finally, the scope and outline of this thesis will be discussed.

1-1-1 Sub-questions

To provide an answer to the main research question, several sub-questions have to be answered first. The sub-questions defined for this research are:

1. *At which system locations can a battery system support the 2030 Dutch regional power networks?*
2. *What are the effects on the regional power grid of implementing a battery system at the system locations?*

3. *What are the costs and benefits of implementing a battery system at the system locations, and how do these compare to other solutions for integrating additional renewable generation?*
4. *How does the institutional setting impact the value of battery systems for the Dutch regional power system?*

Sub-question 1

At which system locations can a battery system support the 2030 Dutch regional power networks?
First, it is crucial to know what the Dutch power system will look like in 2030 and at which system locations battery systems could be implemented to support the integration of additional renewables. That is why for this sub-question (SQ) projections for the 2030 Dutch power system will be analysed, as well as the Climate Agreement and Regional Energy Strategies. Different combinations of battery connection points and renewable generators (system locations) that are likely to occur in the Dutch networks will be introduced.

Second, a case study will be formulated to study the effects a battery system has on a regional network and a regional power station. A Distribution System Operator (DSO) will be asked to provide interesting cases. Criteria for the case study are that it a) is representative of typical elements of the power system, and b) will face problems when integrating a high share of VRES, which can be alleviated by adding a battery system to the network.

Once the case study has been set up, the next step is to model the power station with and without added battery capacity. This part of the SQ will be executed by connecting hourly demand and generation profiles to the determined system. The final part of this SQ will introduce the different generation scenarios for the case study, a visualisation of the network connections in these scenarios and the peak capacity on the network in each of the scenarios.

Sub-question 2

What are the effects on the regional power grid of implementing a battery system at the system locations?
This sub-question will use two different dispatch models to analyse the impact of a battery system on the case study. The first dispatch model will be simple and determine the size of the battery necessary to solve all congestion at the case study location. The second dispatch model will combine battery and curtailment use, because solving all congestion with only a battery system will likely result in needing a substantial battery capacity. It might not be preferable for the battery system to solve for congestion in all situations if that means the total battery capacity is only used for very few hours each year - an issue that a system consisting of a smaller battery combined with curtailment might solve.

During this research phase, the most suitable battery technology will be chosen. For this part, only battery technologies that have been proven to operate at the right scale in real-life applications will be considered. The final step in this SQ is to implement the chosen battery technology at the system locations in the model and determine the reduction in curtailment volume and curtailment costs in the case study, for a range of battery capacities and additional renewable generation scenarios.

Sub-question 3

What are the costs and benefits of implementing a battery system at the system locations, and how do these compare to other solutions for integrating additional renewable generation?
The next step is to evaluate the costs and benefits of integrating the battery system at the different locations. This SQ will do so using a Cost-Benefit Analysis (CBA) approach. To determine if implementing a battery system is beneficial to the network operator, other solutions for handling the excess load from additional renewable generation are also considered. The considered solutions are the large battery solving all congestion, the combined battery and curtailment system, a network upgrade and structural curtailment. It is assumed that whenever the network operator curtails excess generation, he will have to remunerate the generator for this, resulting in curtailment costs. The operator's viewpoint is used for the CBA because the operator will ultimately decide which solution to implement when integrating additional generation into a constrained network.

Sub-question 4

How does the institutional setting impact the value of battery systems for the Dutch regional power system?
This part will examine the institutional setting surrounding battery systems in the Netherlands and the EU, and how this setting influences the value batteries can add to the regional power system. This research will consist of a stakeholder analysis, an analysis of regulations and incentives, and the main barriers to battery system implementation.

First, an overview will be presented of the relevant stakeholders, combined with an analysis of the different possible ownership and operator situations and for battery systems and qualitative business cases for battery systems in the Netherlands. The input for these cases will be gathered during interviews with stakeholders. Second, regulations and incentives regarding battery systems will be analysed. These will include the Climate Agreement, the SDE++, the law on electricity and European regulations. For each of these regulations and incentives, their influence on the likelihood of batteries being integrated into regional grids and the value of battery systems will be assessed.

Third, the main barriers to battery system implementation in regional grids will be determined using information gathered in the first two stages of this sub-question. Then, several dilemmas policymakers concerned with batteries and the energy transition in the Netherlands will face will be presented. To put the conducted research in a broader perspective, the final part of this research question discusses the value of regional batteries in the larger energy system, and identifies four key questions that will influence this value.

Main Research Question

Once the answers to the sub-questions have been determined, it will be possible to answer the final research question. This answer will include a comparison between the different battery system locations, based on their costs, benefits and effect on the regional power system. These results will be discussed within the current institutional frame. Finally, this thesis will make recommendations to ensure the optimal implementation of battery systems in the Dutch electricity system.

1-1-2 Scope

To ensure the study is limited in scope and can be completed within a reasonable time frame, two main assumptions have been made. First, **the battery system will be owned and operated by the regional network operator**. This means that all costs and benefits from the operation of the battery will befall the network operator. Because the battery system is owned and operated by the network operator as an integral part of the network, it is also assumed there are no connection or transportation tariffs for the battery system. Second, **only the effects on the regional network surrounding the battery system are studied**, the interaction of the battery system with the national electricity system is not analysed. The role of battery systems in the larger energy system will be described qualitatively in section 7-6.

1-1-3 Thesis outline

This thesis report consists of multiple chapters, meant to present the process and findings of the conducted research. The following chapters are included:

2. Literature review
This chapter provides background information on the Dutch power system and battery storage technologies. It also reviews existing literature on the integration of battery systems in power networks, and the different functions these systems can have.

3. Battery system locations for supporting the 2030 regional networks
This chapter gives an overview of the projected changes to the Dutch regional networks up to 2030, and it introduces possible system locations for the proposed battery system.

4. Dispatch of the battery system
In the fourth chapter, different models are designed for the dispatch of the battery systems.

5. Case study of an MV-substation: technical analysis
Chapter five introduces a case study of a selected MV-substation. Different load profiles are generated to use in the developed battery models, and the optimal battery sizes and dispatch methods for the case study are determined.

6. Case study of an MV-substation: economic analysis
This chapter compares the proposed battery systems to other solutions for resolving the congestion at the substation, using a cost-benefit analysis from the viewpoint of the DSO.

7. Batteries in the Dutch power system: current and future context
This chapter considers the broader context of batteries in the Dutch power system by analysing stakeholders, regulations and different owner and operator use cases.

8. Discussion
In this chapter, all findings of the research are discussed. Possible limitations to the research and assumptions are also presented.

9. Conclusion
The ninth and final chapter first answers the sub-questions and then formulates an answer to the main research question. Recommendations stemming from the findings and a reflection on the research are also included.

Chapter 2

Literature Review

This literature review was conducted to explore the core concepts relevant to answering the research question and position the research question in the relevant literature. The most important aspects for integrating battery energy storage systems in the Dutch power networks are explored. The structure of this literature review is as follows: Firstly, a thorough background is given on the Dutch power system. Secondly, several technologies used for battery energy storage systems are discussed. Thirdly, research into applications of battery systems in electricity networks is analysed, and different methods of studying battery system integration are discussed.

2-1 The Dutch power system

This section will explain the organisation and functioning of the Dutch power system. It will start by exploring the different activities that make up the power system and explain their most important elements. Then, a rising problem for the Dutch power system will be discussed, and the currently proposed solutions.

2-1-1 Activities in the Dutch power system

In the Dutch power system, there are five main activities. These are generation, transmission, balancing, trading and consumption (Tanrisever, Derinkuyu, & Jongen, 2015). This section aims to explain the most important aspects of each activity and how the activities are integrated to form one functioning power system. The activities are all included in figure 2-1, which is a graphic representation of the Dutch power system.

Generation

The first step in getting power to a consumer is generation. In the Netherlands, the power mix has diversified a lot over the past decades. As shown in figure 2-2, in the early 2000s, most

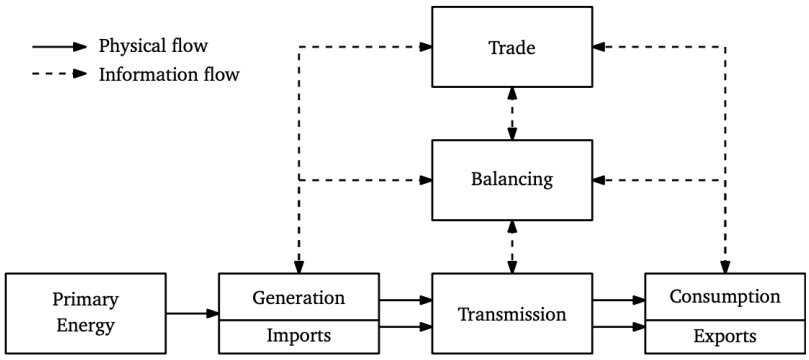


Figure 2-1: The main activities in the Dutch power system (Frunt, 2011).

power was generated using coal and natural-gas fired power plants. In recent years, biomass and wind-powered generation have increased, and coal production has decreased. In 2019 the law 'Wet verbod op kolen bij elektriciteitsproductie' came into force, prohibiting the use of coal for power generation from 2030 onward (Rijksoverheid, 2019b). The projections from 2030 clearly show this, and they also show a steep decline in the use of natural gas. All this lost generation capacity will be compensated by a large increase in solar and wind-powered generation, as shown in figure 2-2.

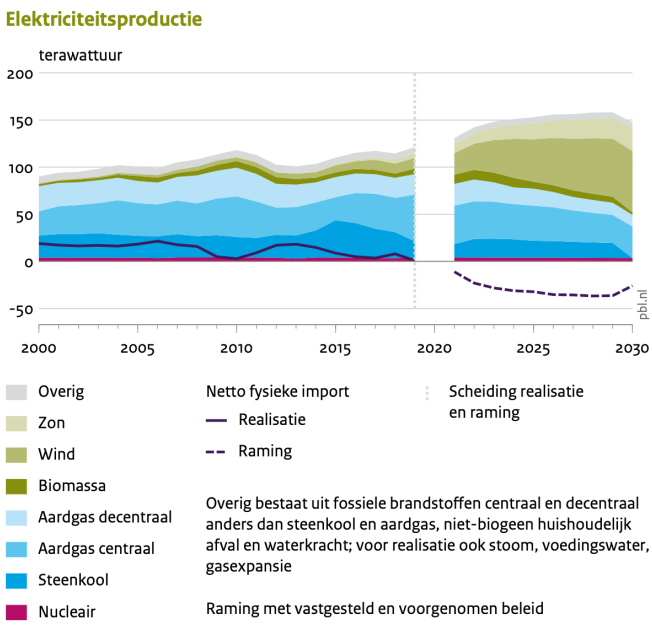


Figure 2-2: Past and projected electricity production in the Netherlands, in annual TWh (PBL, 2020).

Transmission and distribution

Once the power has been generated, it needs to be transported to the consumers. This transport is conducted over the electricity network. The Dutch electricity network, or 'net' in Dutch, has been defined by the law on energy (energiewet) as follows: *'one or more connections for the transport of electricity and the associated transformer-, switching-, distribution- and substations and other devices except when these connections and devices are part of a direct connection or are a part of the installation of a producer or consumer'* (Dutch Government, 1998). The electricity network can be divided into three levels, based on their operating voltage: High-Voltage (HV), Medium-Voltage (MV) and Low-Voltage (LV).

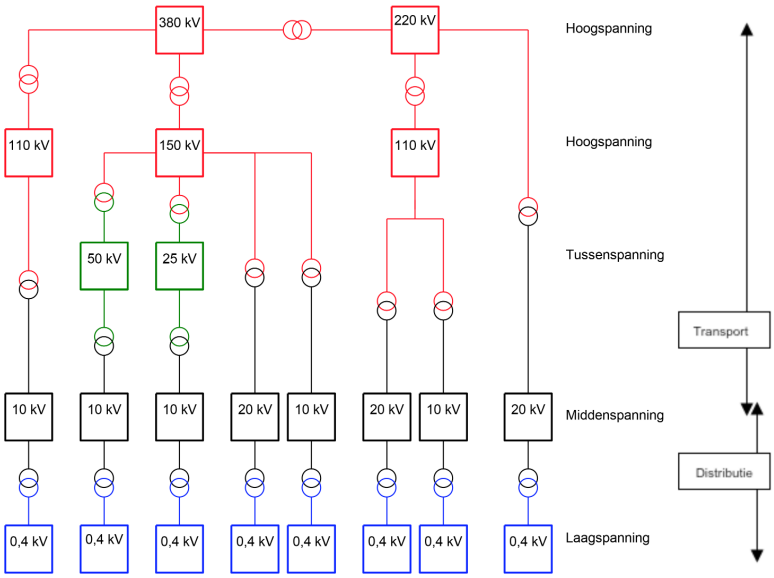


Figure 2-3: Graphic representation of the voltage levels in the Dutch power system (Phase to Phase, n.d.)

- **High-voltage**
  The high-voltage network is mainly used for electricity transmission over large (regional or international) distances. The transmission network operates at a voltage level between 110 kV and 380 kV, to minimize power losses (Phase to Phase, n.d.). TenneT, the Dutch Transmission System Operator (TSO), owns and operates the HV network. The largest electricity generators have a direct connection to the HV network (Tanrisever et al., 2015). The HV network is depicted in the upper, red part of figure 2-3.

- **Medium-voltage**
  The medium-voltage network is used for the regional distribution of electricity from the high-voltage transmission net to regions of consumers (who are most often connected at low-voltage). The Dutch MV networks operate at a voltage level between 3 kV - 50 kV, and the networks are owned and operated by various Distribution System Operators (DSOs) (Frunt, 2011), (Tanrisever et al., 2015). The MV network is depicted in the green and black parts of figure 2-3. The two interconnected circles between the voltage

levels indicate a transformer being used; the voltage must be transformed from the HV level to the MV level.

- **Low-voltage**
  The low-voltage network is used to connect the final consumers to the network. The LV networks operate at a voltage level of 0.4 kV and are owned and operated by the DSOs. Together with the MV networks, they make up the distribution network and deliver power to consumers. There are nine different DSOs in the Dutch power system, which each control their own region in the Netherlands (Tanrisever et al., 2015).

Power is exchanged between the voltage levels to ensure balance at each level. For instance, if in a part of the MV grid there is less electricity generated than consumed, electricity from the HV grid will be transformed to a lower voltage and fed into the MV grid.

Trading

Electricity traders can buy and sell electricity through different power markets, to help match supply and demand. In all of North-West Europe, grids are connected, and markets function in the same way. There are three basic mechanisms for traders to buy and sell power:

- **Bilateral Agreements**
  Bilateral agreements, also called Power Purchasing Agreements (PPAs), are contracts between two parties to trade an agreed-upon power volume at a time and price as stated in the PPA. Because these contracts are often long-term, the power price might be below the regular market price.
- **Day-Ahead Market**
  In this market, electricity is traded any time from 36 to 12 hours before it is actually delivered to the consumer. In this shorter time frame, supply and demand forecasts are more accurate than assumptions made in bilateral agreements. The Day-Ahead Market (DAM) enables parties to adjust for this. All parties wishing to trade submit bid prices for selling and buying electricity to the market operator (In the Netherlands, these are Nordpool and EPEX), which then sorts them into a merit order at the 12-hour mark. The operator's merit order model matches supply and demand in an auction-like way, and the highest accepted marginal bid will determine the price for all bids.
- **Intraday Market**
  In the intraday time frame, forecasting of actual load and supply is even more accurate. This market functions not as an auction but as a continuous market: electricity is traded directly in blocks of 15 minutes, which are called Power Time Units (PTUs).

Balancing

As stated in the introduction, electricity as a commodity has the unique feature that it is hard to store, and therefore supply and demand must be matched closely. Historically, most electricity was generated using coal- or gas-fired generators. These generators use their fuel

to drive a turbine, which generates three-phase power at a frequency of 50 Hz. This frequency is the fundamental grid frequency, and all loads connected to the grid are regulated to this frequency. However, if more electricity is taken from the grid than supplied to it, the grid frequency will decrease, and if the frequency dips too low, a blackout will follow.

Luckily, the system has a defence against frequency deviations: its own inertia. The grid frequency can be compared to the frequency of a spinning flywheel: adding net power supply will make the wheel spin faster and increase its frequency, while adding net power demand will slow the wheel down and decrease its frequency. The wheel's mass determines how fast this change in frequency happens: a heavier wheel will have larger inertia and will be harder to perturb. In the power system, the total of all rotating generators connected to the grid makes up the system's inertia. However, with new RES replacing traditional, inertia-delivering generators, balancing supply and demand becomes more precarious (Wang, Silva, & Lopez-Botet-zulueta, 2016).

Several mechanisms are in place to balance the load and the supply and ensure a stable grid frequency. They all work on the same principle: if the connected demand load is higher than the supply, more power is added to the system. This is called upward reserve power. Conversely, if more supply is connected than the demanded load, power is taken from the system. This is called downward reserve power. There are three different reserve mechanisms in place (Tennet, 2015):

- the Frequency Containment Reserve (FCR), also called primary control.
- the automatic Frequency Restoration Reserve (aFFR), also called secondary control.
- the manual Frequency Restoration Reserve (mFFR), also called tertiary control.

These reserve mechanisms are activated subsequently to solve the frequency violation, starting with primary control and ending at tertiary control. Market parties can put in bids with TenneT for delivering the three kinds of reserve mechanisms.

Consumption

The last step in the Dutch power supply chain is consumption. There are different types of consumers, each with different connection needs. High-consumption industrials are most often connected to the MV network, whereas residential consumers are connected to the LV network.

2-1-2 Rising congestion in the Dutch power system

With increasing renewable generation, high peaks and volatile fluctuations in the power delivered to the network will become more frequent. However, network capacity is limited. Networks were not built to withstand these peaks in production, because expanding network capacity is expensive. In the future, more and more network elements will reach their capacity limits. When there is more demand for transmission capacity than there is transmission capacity available, the network is congested. In this case, it might happen that connected generators or loads will have to be switched off. In the case of generators, this is called generation curtailment. In the case of loads, this can cause a blackout. To prevent these situations,

DSOs can limit new connections in their control areas. In figure 1-2 in the introduction, a map indicating the available transport capacity for generators in the Netherlands is depicted. It is clear from the map that no new large-scale generators can be connected in a large share of the Netherlands because of network capacity constraints. In some areas of the Netherlands, it can now take up to six to eight years to realize a new connection for a large-scale solar PV generator because of network congestion.

There are two basic ways for distribution system operators to deal with congestion: upgrading the network or adjusting the loads on the network. The next section will explain how these actions can solve congestion and when they are applied.

Network upgrades

The Dutch DSOs present their network investment plans every two years, forecasting for the next ten years. In these investment plans, they forecast the loads for the coming decades and find the bottlenecks in their network that will cause congestion. Subsequently, they analyse several possibilities for network upgrades that remedy the congestion and choose the best option by performing a cost-benefit analysis (Stedin, 2020), (Enexis, 2020a), (Liander, 2020). In the past years, more and more attention has been given to the need for network upgrades, and the costs associated with them. For example, TenneT invested €900 million in its networks in 2011, whereas it is currently planning on investing €5-6 billion every year for the next three to five years. Liander invested €475 million in its networks in 2011 and is planning to invest more than 1 billion annually from 2021 (Grol, 2021).

The financial burden of these increasing network costs will be carried by all Dutch power consumers, as network costs are split over all consumers connected to the power network. Why is upgrading the network so expensive? For one, because the Dutch power system is highly reliable: on average, every connection has only 20 minutes of non-availability per year, which is among the lowest in the world (Movares & Netbeheer Nederland, 2020). This is because almost all network components in the Netherlands have been placed under 'N-1' redundancy. The N-1 criterion dictates that the failure of a single component in the network will not lead to the failure of the system. Essentially, because of this criterion, the network is laid out at twice the intended capacity, but the reserve components are only used during failures. Because of the high reliability of the Dutch networks, upgrading them is costly and takes a lot of time: it can take up to seven years to realise a significant upgrade. Indicative time frames for realising a new station in the different network levels have been included in figure 2-4.

Adjusting the network loads

When a network upgrade has not been realised yet, but congestion occurs in a network, the DSO will have to find another solution by adjusting the loads on the network. There are three main ways to do this: curtailment, congestion management and re-directing the power flows.

Curtailment
When congestion is caused by excessive generation or consumption, as is often the case in the Netherlands, a straightforward solution is present: (partially) switching off the generator or

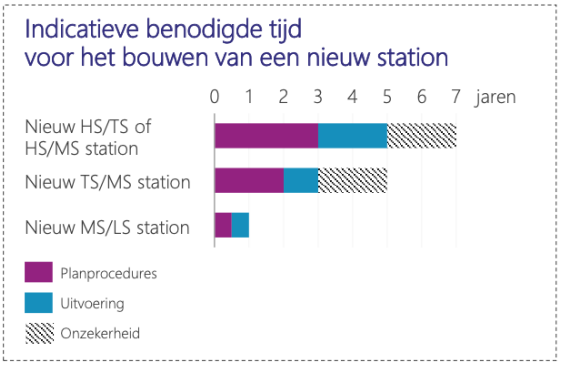


Figure 2-4: Time indications for construction of a new station (Noord-Hollandse Energie Regio, 2020a).

consumer causing the congestion. This remedy is called curtailment. Curtailment of consumer loads is not an option that is used in general by system operators. However, the curtailment of generator loads has gained ground over the past years, as moments of excessive wind or solar generation cause high peaks on the network. These peaks can be managed by reducing the feed-in capacity of these generators to the network temporarily. The impacted parties get remuneration from the DSO for the value of their lost production.

Congestion management

Congestion management is based on the same principles as curtailment: it aims to reduce the peak load on the network by temporarily adjusting generation or demand. In this system, the network operator asks large-scale consumers and generators to place bids for their desired compensation for adjusting their generation or demand at peak load moments.

However, congestion management is not a solution for every congestion area. The authority for consumers & markets (ACM) has imposed strict rules for applying congestion management in the 'Netcode Electriciteit' (Autoriteit Consument en Markt, 2016):

1. The network capacity needs to be sufficient to enable congestion management both technically and safely.
2. The elements partaking in congestion management can be monitored and operated remotely.
3. The period of structural congestion is longer than one year and shorter than four years.
4. There are enough potential participants in the congested area to guarantee a functioning congestion management market.

These four criteria prevent DSOs from applying congestion management in many of their congestion areas (Enexis, 2021). Additionally, DSOs are only allowed to apply congestion management as a temporary measure, until the necessary grid upgrades or changes to the loads to regain full transport capacities have been completed (Autoriteit Consument en Markt, 2016).

Re-directing power flows

The final option to reduce the loads on a certain part of the network is to redirect the power

flows through other parts of the network, with more available capacity. This is a complicated procedure, as it is crucial to know instantaneously which other routes are available and what re-routing the power flow will do to all concerned parts of the regional grid. Additionally, when peaks in renewable generation cause network overloads, re-routing is often not an option. This is because renewable generation peaks will occur simultaneously in most adjacent network regions.

2-2 Battery energy storage systems

This section will give an overview of the latest developments in battery energy storage systems. It will start with an overview of the most relevant technical parameters for battery energy storage system, and then examine the most applied battery types along those parameters. Thereafter, the main functions battery energy storage systems can perform in a power system will be discussed.

2-2-1 Battery system parameters

This section will first explore the technical parameters that define the functioning of a battery energy storage system. As an exhaustive review of battery materials and technologies is not within the scope of this thesis, only four state-of-the-art technologies that are often used for short-term stationary battery energy storage systems are described.

Technical parameters of battery energy storage systems

In a battery, electricity is stored in the form of chemical energy during charging and converted back to electricity during discharging. The process is based on the combination of a reduction and an oxidation reaction (the combination is often referred to as redox). The reduction reaction causes the involved electrode to gain electrons, and the oxidation reaction causes a loss of electrons at the other (Koohi-Fayegh & Rosen, 2020). As a result, the electrons flow through an external circuit, allowing for external electricity use. The processes of charging and discharging are depicted in figure 2-5.

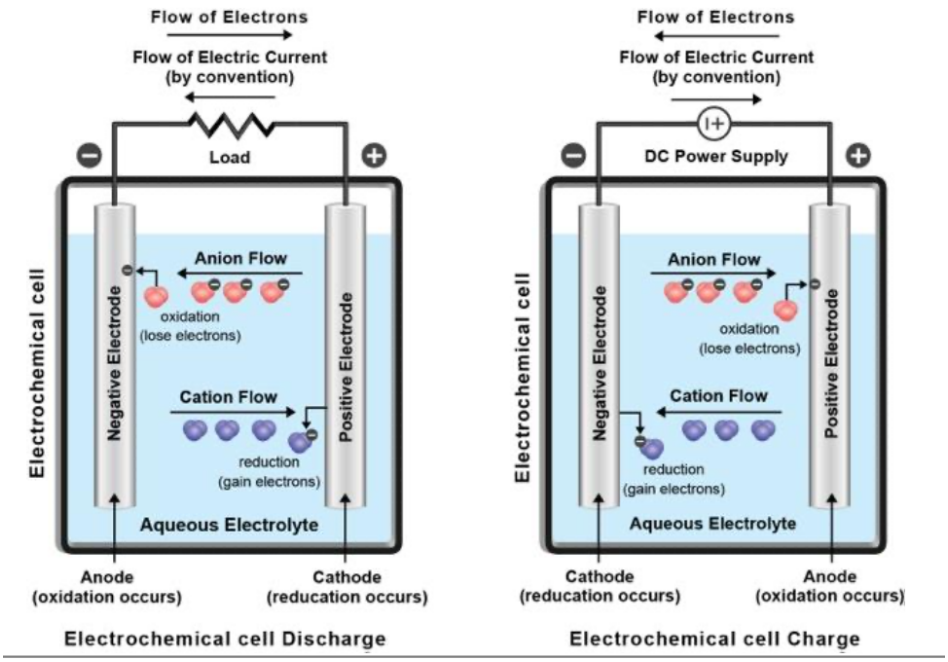


Figure 2-5: Graphic representation of the charging and discharging of a battery (Ghiji et al., 2020)

There are several parameters that determine the operation of a battery. The most important ones are described below.

Capacity: The capacity of a battery C_{bat} is the total amount of electricity it can store. Battery capacity is often described in Ah, indicating the number of hours a battery can deliver one Ampere of current. By multiplying the battery capacity C_{bat} by the rated voltage of the battery V_{bat}, the energy capacity is obtained in Wh (Smets, Jäger, Isabella, van Swaaij, & Zeman, 2016).

State of Charge: the State of Charge (SoC) of a battery is defined as the amount of energy that can be discharged as a percentage of the battery's total capacity (Goodenough & Park, 2013). Batteries often have a range of SoC that ensures optimal operation, known as the SoC limit. Some types of batteries degrade faster when operating at the limits of their SOC.

Energy Density: The energy density of a battery is the amount of energy that can be stored per battery volume or mass, often expressed in Wh/kg or Wh/m^3 (Zobaa et al., 2018).

Cycle life: the cycle life of a battery is defined as the number of charging and discharging cycles the battery can perform until its capacity fades to 80% of its initial value (Goodenough & Park, 2013). The speed at which battery capacity fades is influenced by many factors, of which the most important are temperature and the SoC (Smets et al., 2016).

C-rate: the C-rate is a measure for the rate at which the battery can be discharged, relative to its capacity. It is calculated by dividing the maximum capacity discharged in one hour by the battery's total capacity. Therefore, a C-rate of 1 indicates that the battery can fully discharge in one hour (Smets et al., 2016).

Cycle efficiency: The cycle efficiency of a battery is the ratio between electrical energy output and electrical energy input. Because both conversion steps are included, it can be described as the 'round-trip' efficiency (Díaz-gonzález, 2016).

Storage duration: The storage duration is the amount of time a battery can effectively store energy for. This time is limited because batteries always experience a certain amount of self-discharge (measured as a percentage of their total capacity). The rate of self-discharge and thus the effective duration of storage depends heavily on the battery material used.

Economic parameters

Next to the technical parameters, there are other crucial factors in determining if a battery energy storage system is a feasible option for a power system. The most important ones describe the different costs associated with a system.

CAPEX: the Capital Expenditures (CAPEX) of a battery system are the costs associated with purchasing and installing the system. These costs are often defined in terms of €/kWh.

OPEX: the Operational Expenditures (OPEX) of a battery system are the costs associated with operating the battery system. These costs are often defined in terms of €/kWh.

LCoE and LCoS: in power systems, different sources of energy are often compared based on their Levelized Costs of Energy (LCOE). These are the total costs (CAPEX+OPEX) associated with producing energy over the lifetime of the production unit. The LCoE is expressed in €/kWh. The Levelized Costs of Storage follows the same method: the total costs of storing energy are expressed in terms of the amount of energy stored (€/kWh).

2-2-2 Battery system technologies

As the focus of this study will be on real-life utility-scale applications of battery systems by 2030, only technologies that are feasible to implement in that time frame and with a proven track record are considered. The most commonly used battery technologies in that category are lead-acid, sodium-sulfur, flow and lithium-ion. In figure 2-6, the annual global capacity additions for these battery technologies are depicted.

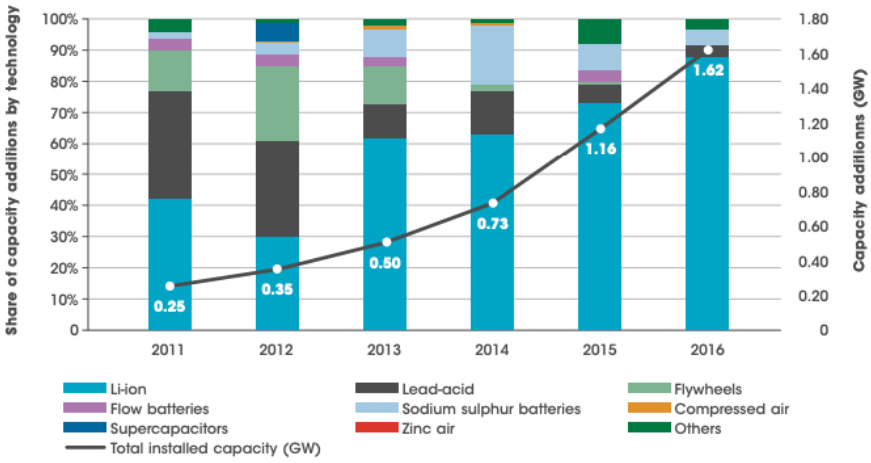


Figure 2-6: Battery technologies: annual deployment per technology (International Renewable Energy Agency, 2019)

Lead-acid batteries
The lead-acid battery is the most mature battery technology around, with the lowest costs. The positive electrode contains lead dioxide and the negative electrode lead. The electrolyte is made from sulphuric acid. Lead-acid batteries can reach efficiencies of 80-90% and have a low self-discharge (less than 0.1% per day) (Olabi et al., 2021), (May, Davidson, & Monahov, 2018), (Sufyan, Rahim, Aman, Tan, & Raihan, 2019). However, lead-acid batteries have a lot of drawbacks: they have a limited cycle life (especially when exposed to low or high temperatures), a low energy and power density (30 Wh/kg, 180 W/kg), and their capacity can decrease when faced with deep or rapid discharges (Zhang, Wei, Cao, & Lin, 2018), (Olabi et al., 2021). Also, they contain hazardous materials which can harm the environment if not recycled correctly (May et al., 2018). Therefore, it is no surprise that the use of lead-acid

batteries in power systems has been on the decline, as shown in figure 2-6.

Sodium-sulfur batteries
In Sodium-sulfur (NaS) batteries, the negative electrode contains molten sodium and the positive electrode sulfur. The electrodes are separated by a solid ceramic, which functions as the electrolyte in this system. Generally, sodium-sulfur batteries are highly efficient (>85% efficiency), and they have a long cycle life (May et al., 2018), (Zhang et al., 2018). In addition, they have a high energy density, in the range of 150-170 kWh/m^3, and they allow for fast charging and discharging responses within milliseconds (Sufyan et al., 2019). However, the system operates at temperatures between 300-350 °C (Zhang et al., 2018). This can pose a challenge when incorporating the battery into power systems, especially when the battery is meant to operate intermittently. One great advantage to sodium-sulfur batteries is the almost infinite raw material reserves of sodium available at affordable prices (Delmas, 2018).

Flow batteries
Whereas other battery types are best suited for short-term storage because of their self-discharge, flow batteries have been designed to overcome this issue. These batteries are made up of two reservoirs containing liquid chemical electrolytes, separated by a membrane. The most common flow battery technologies are vanadium-redox batteries (VRB), which have reservoirs filled with vanadium in different valence states, separated by a membrane (Zhang et al., 2018), (May et al., 2018). These batteries can reach efficiencies ranging from 75-85% (Sufyan et al., 2019). However, flow batteries generally have a lower energy density than other battery types. Flow batteries are regarded as a good option for longer storage periods, but can also respond within milliseconds (Clemente & Costa-Castelló, 2020), (Yano, Hayashi, Kumamoto, & Shibata, 2017). Because of their use of reservoirs, the battery capacity is not limited and they are best suited to utility-sized storage (May et al., 2018). Currently, the biggest operational flow battery (15 MW/60 MWh) is located in Japan (Yano et al., 2017). In China, there are plans to build a 200 MW/800 MWh vanadium flow battery (Norge Mining, 2020).

Lithium-ion batteries
In Lithium Ion (Li-Ion) batteries, the positive electrode contains metal oxides and the negative electrode graphitic carbon (Fan et al., 2020). The electrolyte consists of organic carbonates with dissolved lithium salts (Krishan & Suhag, 2019). Lithium-based batteries are currently seen as one of the most promising technologies, because of their high energy density, low self-discharge, high cycle life and fast reaction time (Kim, Song, Son, Ono, & Qi, 2019), (Koohi-Fayegh & Rosen, 2020), (Xu, Oudalov, Ulbig, Andersson, & Kirschen, 2018). Li-ion batteries can reach energy densities of 250 Wh/kg, power densities of 2000 W/kg and are highly efficient (85-95%) (Fan et al., 2020), (Krishan & Suhag, 2019).

Because of these characteristics, Li-ion batteries are ideally suited for portable devices and electric vehicles. These applications of Li-ion batteries have caused an accelerated development of the technology, which in turn has led to improving technical features and rapidly decreasing prices (International Renewable Energy Agency, 2019). Because of these develop-

ments, Li-ion has also been applied for stationary, grid-scale energy storage. At the moment[1], the largest ever Li-Ion battery system is situated in Moss Landing, California. It has a 300 MW power capacity and 1200 MWh energy capacity (Vistra Corp., 2021).

From figure 2-6 it is clear that Li-ion battery adaptation is steadily increasing. However, the Li-ion battery has some drawbacks. Firstly, although costs fell by 80% from 2010 to 2017, Li-ion batteries are still relatively expensive (IRENA, 2017a). Nevertheless, costs are expected to decrease even further: according to IRENA, the total installed costs of a stationary Li-ion battery could fall by an additional 54-61 by 2030%. Secondly, Li-ion batteries are prone to degradation at higher temperatures (>65°) (Fan et al., 2020). The batteries can also pose safety risks when operating at higher temperatures because they are highly flammable and have a high energy density (May et al., 2018). To operate Li-ion batteries safely, extensive battery monitoring systems are crucial.

2-2-3 Battery system use cases

As stated before, batteries can provide many advantages to the power system because of their wide range of possible applications (Hesse et al., 2017). This section will explore the different functions batteries can perform in energy systems and the benefits associated with each of them. There are three main groups of utility-scale battery functions: ancillary services, grid support and energy system optimization.

Ancillary services

Ancillary services are all services contracted by the TSO and DSOs to ensure stable operation of the power system under fluctuating supply and demand. Battery systems can support stable operation by reacting rapidly to fluctuations in the power system (Hesse et al., 2017). The Dutch TSO, TenneT, divides ancillary services into five categories (TenneT, n.d.):

- Balancing reserves: these are reserves of generating capacity or loads that can be activated when there is an imbalance between supply and demand. The balancing reserves consist of the Frequency Containment Reserve (FCR), the Frequency Restoration Reserves (aFRR), and the manual Frequency Restoration Reserves directly activated (mFRRda). Flywheels are often used as spinning reserves because of their rapid response time. However, certain types of batteries would also be suited to this task.
- Reactive Power: to control the voltage quality in the grid, TenneT contracts generators that can increase or decrease the reactive power at their connection point.
- Redispatch: TenneT can contract parties to shift their feed-in and take-out of power elsewhere, in the case of a congested grid.
- Black Start facility: after a power outage, black start facilities are used to restore power in the network.
- Compensation of losses and sustainability of grid losses through Guarantees of Origin (GoOs): TenneT compensates for the grid losses by contracting for extra supply.

[1] July 2021, battery systems sizes are increasing rapidly.

Grid support

Grid support are services that help maintain stable network conditions, but are not necessarily defined as ancillary services by the TSO and DSOs. There is some overlap between grid support and ancillary services, depending on the network regulations applied. There are two main ways in which battery systems can provide grid support:

- Voltage support: VRES generation and variations in power demand cause voltage fluctuations in power transmission networks, which are harmful to the system. Battery systems can be operated and controlled to reduce voltage fluctuations and peak voltages on lines (Hesse et al., 2017).
- Grid investment deferral and congestion management: adding battery systems to a power grid can reduce the peak power demanded from grid components, and therefore reduce the need for upgrading them (Spiliotis, Claeys, Gutierrez, & Driesen, 2016). If a system is already congested, adding battery systems can relieve (part of) that congestion by reducing the peak capacity on the grid (Marnell, Obi, & Bass, 2019).

Energy system optimization

Battery systems can benefit the energy system by optimizing the timing of energy generation and use. There are four main ways in which battery systems can help optimize the energy system:

- Reduce VRES curtailment: when VRES are connected to the grid, peaks in generation can cause excess loads on the network. This might lead the operators to curtail their generation, or VRES generators to be put on a smaller connection than their actual production capacity. These curtailment losses can be mitigated with a battery system.
- Increase self-sufficiency: PV prosumers can drastically increase their share of self-generated energy use when adding a battery to their home system.
- Balancing: because of its ability to time-shift power generation, adding battery systems to the power system will facilitate a better balance between supply and demand. The two most common forms of balancing using battery systems are peak shaving and load levelling.
- Energy Arbitrage: a battery system used for energy arbitrage will trade on the electricity markets and optimise its charging schedule for maximum profits. The battery system will charge during low-price moments and discharge during high-price moments. As low-price moments are often moments of oversupply or under-demand, executing an arbitrage strategy will most often help in the balancing of a system.

Research into grid-level battery applications

A selection of papers that analyze the role of batteries in power systems was reviewed. Their main characteristics can be found in Table 2-1. From this review, it has become clear that the papers can be categorised using various criteria. First of all, the papers can be categorised on the different use cases they identify and analyse for batteries. These use cases are indicated in the second column of table 2-1. Secondly, the method researchers use for determining the value of the battery use case is varied but highly dependent on the battery use case. Thirdly, the integration of battery systems in the power system differs: researchers vary the connection point to the grid between HV, MV and LV, and different (renewable) energy sources integrated into the system. Fourthly and finally, different methods for optimising battery operations are discussed and compared.

Table 2-1: Overview of reviewed literature. battery (Bat.) use case, RES sources, and battery (bat.) network integration location are included. GS indicates grid-support, ESO indicates Energy System Optimization and AS indicates Ancillary Services.

Article	Bat. use case	RES included	Bat. integration location
(Idlbi et al., 2016)	GS	Wind, Solar PV	MV distribution grid both urban and rural
(Purvins & Sumner, 2013)	ESO	Wind	MV
(Resch, 2017)	GS, ESO, AS	Total system	All of Germany
(Grover-Silva, Girard, & Kariniotakis, 2018)	GS, ESO	Solar PV	MV distribution grid in France
(Segundo Sevilla et al., 2018)	GS, ESO	Solar PV	LV (residential PV) MV (next to distribution transformer)
(Faessler, Schuler, Preißinger, & Kepplinger, 2017)	ESO	Solar PV	LV rural distribution grid
(Reihani, Sepasi, Roose, & Matsuura, 2016)	ESO, GS	Solar PV	unspecified
(Zeh, Rau, & Witzmann, 2016)	ESO	Solar PV	MV large scale bat. LV home storage
(Manganelli, Nicodemo, D'Orazio, Pimpinella, & Falvo, 2018)	AS	Wind + Solar PV + hydro	HV/MV substation
(Maeyaert, Vandevelde, & Döring, 2020)	AS	Solar PV	LV prosumers in distribution grid
(Karanki & Xu, 2017)	AS	Wind	MV/LV substation
(Marnell et al., 2019)	AS, GS, ESO	Total system	HV
(Spiliotis et al., 2016)	GS	Solar PV	LV feeder nodes
(Denholm et al., 2016)	ESO	Wind + Solar PV	unspecified
(Fleer et al., 2018)	AS	Total system	unspecified
(Gamage, Withana, Silva, & Samarasinghe, 2020)	GS	Solar PV	LV residential
(Klausen, Resch, & Bühler, 2016)	ESO, AS	Total system	unspecified
(Li et al., 2016)	AS, ESO	Wind	HV at wind farm
(Mallapragada, Sepulveda, & Jenkins, 2020)	AS, GS, ESO	Wind + Solar	unspecified
(Mateo et al., 2016)	ESO, GS	Distributed generation units	MV/LV secondary substation
(Martins & Miles, 2021)	AS, ESO	Wind + Solar	MV (at generator) LV (home systems)

Grid-connected battery use cases

As can be seen in table 2-1, most of the found research papers focus on energy system optimization with battery systems. In this category, papers that focus on balancing and energy arbitrage are dominant: (Klausen et al., 2016) analyses the different value sources of battery systems performing arbitrage in the German Energy market. (Martins & Miles, 2021) also develops arbitrage strategies combined with ancillary services for the UK power market, and assesses them from the point of view of the business owner operating the battery. Their results differ: (Martins & Miles, 2021) finds that providing certain ancillary services can result in the highest revenues, while (Klausen et al., 2016) finds only performing energy arbitrage to be more lucrative. The disparity in their findings might be caused by the fact that their research was performed for different markets, which could have different systems for ancillary services.

Several papers aim to reduce curtailment or optimize the use of connected VRES sources. For instance, (Purvins & Sumner, 2013) optimizes battery system in a hypothetical distribution grid for optimal utilisation of the connected wind turbines. This research shows that battery

systems can be used to store a large share of the generated energy surplus.

Another focus direction found in multiple papers is the different use cases available to prosumers. (Zeh et al., 2016) and (Faessler et al., 2017) both focus on increasing self-sufficiency for prosumer households and decreasing curtailment. Both papers focus on a system with solar PV, but (Faessler et al., 2017) integrates batteries in an LV rural distribution grid, while (Zeh et al., 2016) compares MV-connected large-scale battery system to LV-connected home-storage battery system.

Among the papers that focus on battery systems for ancillary services, (Manganelli et al., 2018) assumes a unique AS use-case: the possibility of using battery systems for grid restoration after a large blackout. This research shows that a battery system situated at an HV/MV substation can support restoration plans, but coordination between generators and the battery system operator is essential. (Maeyaert et al., 2020) explores how prosumers can use battery systems to deliver ancillary services to lower their electricity bill under a variable AS pricing strategy. This paper shows that battery systems in distribution grids can be used to provide different types of AS and increase economic benefits for prosumers.

There are only three papers with the sole focus of providing grid support. (Idlbi et al., 2016) integrates a battery system in an MV distribution grid to support voltage compliance, both for a large share of solar PV generation and a large share of wind generation. The system performs better when integrated with solar PV, because of the diurnal cycle. (Gamage et al., 2020) integrates small-scale battery systems at each node in a distribution line, and power flow simulations show reductions in voltage violations along that line. (Spiliotis et al., 2016) also models a battery system integration on LV nodes with PV systems connected, aiming to keep power flows in the lines within the line capacity. This paper shows that grid investments can be deferred or reduced by adding a battery system to the power system.

As can be seen from table 2-1, many papers use battery system for a combination of use cases. The section on battery system valuation will explain the logic behind this practice.

Battery system integration at varying system locations

Most studies differentiate between the integration of batteries at distribution-grid level and at residential dwellings. (Grover-Silva et al., 2018) proposes an adjusted optimal power flow algorithm to determine optimal battery sizing and location in a distribution grid. However, this algorithm puts a small storage volume at every node unless manually corrected. (Karanki & Xu, 2017) uses particle swarm optimization modelling to minimize system losses and obtain the optimal location for a battery system in a distribution grid with high wind generation. This paper shows that when a battery system is optimally sized and located, system losses can be reduced significantly (>10%). However, this paper only applies the model to one particular power system, and does not consider the economic viability of the battery system.

(Faessler et al., 2017) assesses power quality improvements for two locations of battery systems: one of distributed storage at every dwelling, and one of central storage. Both locations improve power quality; central storage results in fewer distribution losses and a minimal voltage drop/rise, while distributed storage achieves lower peak-to-average-power ratios.

(Reihani et al., 2016) has shown that a battery system can be used for peak shaving and power smoothing at the substation end of a distribution feeder, but does not mention the monetary benefits such services could deliver. (Manjunatha, Korba, & Stauch, 2013) have

shown that peak shaving results can be improved using model-predictive control. Their system was applied to a real battery system in Switzerland.

(Segundo Sevilla et al., 2018) compares two different system locations for battery systems in a system with high PV penetration: a residential and a central battery system managed by the DSO. They find that both the LCOES and the LVOES (Levelized Value of Energy Stored) are higher for the residential location: individual battery costs are higher, but residential consumers can discharge their battery at retail electricity prices, which increases their benefits.

(Zeh et al., 2016) assumes ideal placement of large-scale storage systems and compares the economic and grid effects to distributed home-storage systems. Large-scale storage comes out favourable in both categories: the maximum voltage in the grid is lower in the large-scale case. Especially in grid areas of at least 50 customers, large-scale storage systems perform better in terms of maximum voltage than home storage systems. This study shows that being able to choose the connection point for a storage system is highly advantageous for the grid operator and voltage quality provision.

Valuation methods for grid-connected batteries

Previous studies use many different methods to assess the value battery systems add to the power system. The method used by most is a cost-benefit analysis (CBA). (Idlbi et al., 2016) analyses the value a battery system can provide to an MV distribution grid, when used as a grid-support mechanism for voltage compliance and to avoid grid reinforcements. The CBA shows that in urban areas, battery systems can be more economically viable than grid reinforcements. However, regardless of location, power curtailment is more cost-efficient than all other options. The author suggests that using the battery system for other purposes when it is not needed for voltage compliance could increase its cost-effectiveness.

(Segundo Sevilla et al., 2018) again compares using battery systems to PV curtailment, but uses other metrics for the economic evaluation of the battery system: the Levelized Cost of Energy Storage (LCOES) and the Levelized Value of Energy Storage (LVOES), which measures the total revenues and benefits of a battery system. (Denholm et al., 2016) applies another interesting metric: the Economic Carrying Capacity (ECC). This metric specifies how much extra VRES capacity a system can bear economically when a battery system is added. This paper shows that adding a battery system can indeed increase the ECC and decrease total system costs, but the specific value of the battery system differs greatly per power system.

There are two main ways research analysing grid support battery system applications evaluate the addition of batteries to a power system. Firstly, there is the grid-technical way: research analyses the impact battery system additions have on critical grid parameters, such as peak voltage on grid lines. (Reihani et al., 2016) shows that batteries can effectively be used for peak shaving and power smoothing by lowering the peak load power on the system. (Gamage et al., 2020) analyses the effects a battery system has on a distribution network using optimal power flow simulations, and shows that adding a battery system is beneficial to the voltage profiles of distribution lines.

The second method of evaluating grid support battery system applications is in terms of the value of deferred grid investments. These are analyzed in (Purvins & Sumner, 2013), (Segundo Sevilla et al., 2018), (Spiliotis et al., 2016) and (Mateo et al., 2016). Research by (Spiliotis et al., 2016) has shown that DSOs facing high VRES penetration can significantly

reduce their network costs by adding a battery to the system. (Mateo et al., 2016) uses Reference Network Models to compare network expansion costs with and without the battery system, and shows significant potential for network savings. However, according to this research, Li-Ion battery systems need a target costs of 60-80 € /kWh to become economically viable. This target is not (yet) within reach: (IRENA, 2017a) predicts costs between 145 - 480 $/kWh, and (NREL, 2019) predicts overall costs between 124-338 $/kWh for 2030 and 76-258 $/kWh for 2050.

Overall, most papers evaluating the economic side of implementing battery systems for specific use cases suggest that combining use cases could make battery systems more economically viable in the future (Marnell et al., 2019), (Mateo et al., 2016), (Martins & Miles, 2021). (Klausen et al., 2016) gives an overview of combined use-case possibilities in the German power markets. However, when (Klausen et al., 2016) compares the use cases of only performing arbitrage, and performing both arbitrage and frequency support, arbitrage-only provides higher benefits to the battery owner. Limitations to their simulation are the fact that only current market conditions and regulations are used: substantial changes in both conditions and regulations are to be expected with increasing shares of VRES. (Martins & Miles, 2021) also compares different combinations of energy system optimization and ancillary service use cases, and has found that using battery systems for arbitrage and frequency response in the UK balancing market could provide the shortest payback period for the battery owner.

(Mallapragada et al., 2020) correctly notes that although combined use cases suggest higher values, their usefulness remains limited in practical applications because it is not possible for one party to extract all sources of value. (Mallapragada et al., 2020) notes another crucial conundrum of the value of battery systems in power systems: with increased VRES penetration, the value of storage systems will increase. However, with increased penetration of storage systems, their value will decrease again.

Optimisation of battery system operation

To ensure that the battery system operates optimally for achieving its chosen goal, many research paper use optimisation algorithms. (Resch, 2017) reviews several studies and compares the most common optimisation methods used for battery system research. The main categories discerned in his research are mixed-integer models, discrete models and continuous models. From this selection, mixed-integer models are the most commonly used linear models. In previous research, (Faessler et al., 2017) has shown that for long-term modelling, linear models perform battery system simulations significantly faster than quadratic or dynamic models and realise close to equal results (Faessler, Kepplinger, & Petrasch, 2016).

(Spiliotis et al., 2016) uses both mixed-integer linear programming and mixed-integer non-linear programming to assess the value of local storage units to defer grid investments. The non-linear programming model is added to study the potential of mobile battery system added to various locations in the system. (Klausen et al., 2016) chooses to apply a simple linear programming approach to optimise battery operations for both a single and a stacked revenue model. This paper highlights the large drawback to most optimisation methods: they require perfect foresight of the conditions in which the battery will operate. In reality, such foresight is never possible. Solutions to this problem can be found in the method itself: (Li et al., 2016) uses linear programming to derive an optimal battery operation schedule to minimise the total system costs. This paper then determines a fixed operating schedule based on the outcomes of the linear optimisation, which still manages to reduce the total system costs.

Chapter 3

Battery system locations in the 2030 regional networks

To determine where in the regional power system a battery system can add value for the network operator, this chapter will analyse projections for the Dutch regional power system in 2030. Both power generation and consumption are set to undergo drastic changes, and this chapter aims to provide an overview of the changes most relevant to this research. First, the current and future generation side of regional power systems will be reviewed, followed by projections for the consumption side of regional power systems. Because this study is mainly concerned with renewable power generation, the consumption section will only indicate some main trends and their effects on the power system. Then, the link between generation and consumption, the distribution system, will be discussed. Finally, an overview of potential system locations for a battery supporting the regional networks will be given.

3-1 Regional power generation in 2030

For projections about the dominant generation types in the national and regional power system in 2030, the Climate Agreement is the primary source. However, to get a more detailed view, subsidy requests for renewable power generation will also be analysed.

The Dutch climate agreement

The Dutch climate agreement was drafted in 2019 and has one main goal: to reduce Dutch CO_2 emissions to 49% of 1990 levels by 2030 (Rijksoverheid, 2019a). To reach these goals, measures are proposed, divided over five sectors: the built environment, mobility, agriculture & land use and electricity. Measures that span across sectors are also introduced. Furthermore, if the European Union decides to increase the EU emission reduction target to 55%, which is likely, the Netherlands will follow this goal and impose additional measures. The relevant measures for this thesis are included in the electricity sector and the cross-sectoral measures.

Electricity sector

The vision for the electricity sector in 2050 presented in the climate agreement is a carbon-free electricity system. For 2030, the goal is to reduce 20.2 Mt CO_2 eq. in the electricity sector. To reach this goal, the Dutch government wants to increase renewable electricity production to 84 TWh per year by 2030. Table 3-1 shows how this volume of electricity is split over offshore wind and renewables on land, which are solar PV and onshore wind generation.

Table 3-1: Ambitions for renewable electricity production in 2030, adapted from the Dutch climate agreement (Rijksoverheid, 2019a).

Energy Source	**49% base package**	**55% additional measures**
Offshore wind	49 TWh	
Renewable on land (>15 kW)	35 TWh	
Other renewable options (incl. carbon-free controllable capacity)	TBD	
Total	**84 TWh**	**120 TWh**

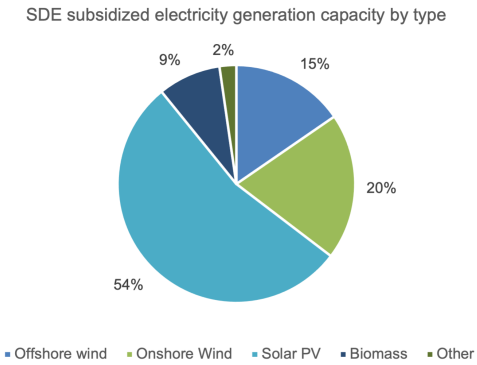
As this research focuses on the MV grid, the 49 TWh of HV-connected offshore wind are not the most relevant. However, a large share of the renewables on land (mainly wind and solar) will likely be connected to the MV grid. The other renewable options, whose generation volume still remains determined, include carbon-free controllable generation capacity. The climate agreement expects 15-40 TWh of this capacity to be necessary for a well-functioning power system in 2030. Battery energy storage systems could provide part of this controllable capacity in 2030. The recently released report II3050 even estimates 27-54 GW of flexible power by batteries will be necessary to balance the system by 2030/2050 (Gasunie et al., 2021).

Expected solar and wind on land

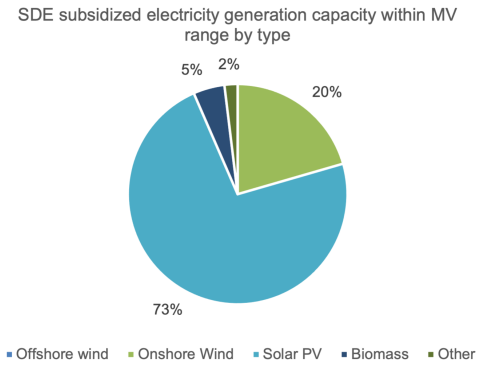
To get an indication of the size and number of MV-connected solar and wind generators in 2030, the projects that have received SDE+ or SDE++ subsidy and are currently under management have been analysed. This data set contains 39195 renewable electricity generation projects that are set to receive subsidies or are already receiving subsidy[1].

From figure 3-1a, it is clear that solar PV and onshore wind make up the largest share of total capacity in the SDE scheme. In general, electricity generators in the range of 0.16-10 MW are connected to MV networks or MV/HV substations (Liander, 2021c). Figure 3-1b shows that solar PV is the dominant source of power generation within this range, followed by onshore wind.

[1]The data set contains both realised and projects to be realised in the future, of which some might never be realised.



(a) Generation capacity in SDE



(b) MV-generation capacity in SDE

Figure 3-1: Share of total electricity generation capacity (MW) with allocated SDE subsidy as of January 2021. In total, 33.6 GW of generation capacity has been included in the subsidy. 14.1 GW of this capacity falls within the 0.16-10 MW MV-connected range. Data from (Rijksdienst voor Ondernemend Nederland (RVO), 2021). Figures contain all allocated subsidy requests, which includes both realised and to realise projects.

3-2 Regional power consumption in 2030

There are several groups of electricity consumption that are likely to increase under the measures proposed in the climate agreement:

- **Built environment**
  Electricity use in the built environment is set to increase mostly due to changes in space and water heating, cooling and cooking, when consumers shift from natural gas to electricity for these activities. Especially space and water heating will have a pronounced effect on the total electricity balance because demand for these services is often highest during cold periods, with little electricity generated by solar PV (CE Delft, 2020).

- **Mobility**
  The number of electric vehicles on the road in the Netherlands is set to increase from a little over 100,000 in 2020 (1.3% of all personal vehicles on the road) to 1.9 million in 2030 (Centraal Bureau voor Statistiek, 2020), (RVO, 2020). Additionally, the aim is that from 2030 onward, all new vehicles sold are zero-emission (Rijksoverheid, 2019a). Not only personal vehicles are set to electrify, busses and goods transport will also partly shift to electricity by 2030. With this increase of electric vehicles, electricity demand for charging is set to grow rapidly in the next decades.

- **Industry**
  According to the climate agreement, the Dutch industrials will have to reduce their CO_2 emissions by 19.4 Mton CO_2 eq. compared to 2015 levels. A significant share of this reduction will likely be caused by electrifying industrial processes. Examples of this include using electric heat pumps and electric boilers for industrial heat production. Globally, about 20% of the energy used in industry is in the form of electricity. It has been estimated that this share could grow to about 40% with technologies available today (Roelofsen, Somers, Speelman, & Witteveen, 2020).

Whereas industry is often coupled to the HV network, the effects of both increased electrification in mobility and the built environment will certainly be noticeable on the LV and MV networks. These effects will be taken into account in the modelling phase.

3-3 Regional power distribution in 2030

For realising the 35 TWh of renewable electricity generation planned on-shore[2], the Dutch government has instructed local and regional authorities to develop Regional Energy Strategies (RES). The TSO and DSOs collaborate with regions on their RES to ensure generation capacity is added in places where network capacity is available or can be expanded. The climate agreement also emphasises that increased renewable electricity generation will take a toll on the electricity networks, and that it will be challenging for the TSO and DSOs to offer sufficient network capacity for the planned increase in renewables, while at the same time minimising the total network costs.

For example, in the concept-RES of the region Noord-Holland Noord, it is concluded that the stated RES plans cannot be integrated into the current electricity networks because of capacity constraints (Noord-Hollandse Energie Regio, 2020a). The growing number of generators connected to the grid has the most significant impact on the networks. The RES states that in 2030, 19 of the 29 transformer stations will have reached their maximum capacity. Many other RES documents, including Noord-Holland Zuid and Flevoland, also raise this issue "(Noord-Hollandse Energie Regio, 2020b), (Flevolandse Energie Agenda, 2020).

To determine which infrastructural challenges will arise from the increase in renewable electricity generation, GasUnie, TenneT, and the DSOs have developed the 'integrale infrastructuurverkenning 2030-2050 (II3050)', which will be leading in the grid investment plans for TenneT and the DSOs (Gasunie et al., 2021). Currently, network investments are made based on the "verzwaren tenzij" principle. This principle describes criteria that system operators can use to choose between grid reinforcements and market-based flexibility measures (Overlegtafel Energievoorziening, 2018).

Another challenge is that to reach the concept RES goals, DSOs will have to scale up their operations. For example, Liander will have to expand or develop three transformer stations per year in Noord-Holland Noord. In previous years, Liander averaged 2 new or expanded stations per year over their whole service area (which includes all of Noord-Holland, Flevoland, Gelderland and a share of Friesland and Zuid-Holland). In the region "Noord-Holland Zuid", 23 out of 55 transformer stations are expected to reach their capacity limit by 2030 (Noord-Hollandse Energie Regio, 2020b).

Overall, drastic changes are happening in the electricity network, and DSOs are looking for ways to integrate additional renewable generation in congested networks. The next section will identify the different solutions this research compares for a DSO in a constrained regional network.

[2]Only generation capacity of > 15 kWp counts towards this goal, many smaller-scale solar projects are not included.

3-4 System locations for a battery system supporting the regional network

With increased renewable capacity connected to the regional power system, congestion will rise. As explained in section 2-1-2, there are two main ways to solve this congestion: by increasing the network capacity or decreasing the load on the network. A battery system could provide both solutions to the network, examples of which have been discussed in section 2-2-3. This thesis will analyse varying forms of both solutions for a range of additional renewable generation scenarios. All solutions to be analysed are included in figure 6-1, except for the fact that instead of only the wind generator depicted in the figure, a range of renewable generators will be analysed. From the previous sections, it has become clear that wind- and solar powered generation will become dominant in the Dutch MV networks in 2030, so the generators included will be wind, solar PV and a combined wind and solar generator.

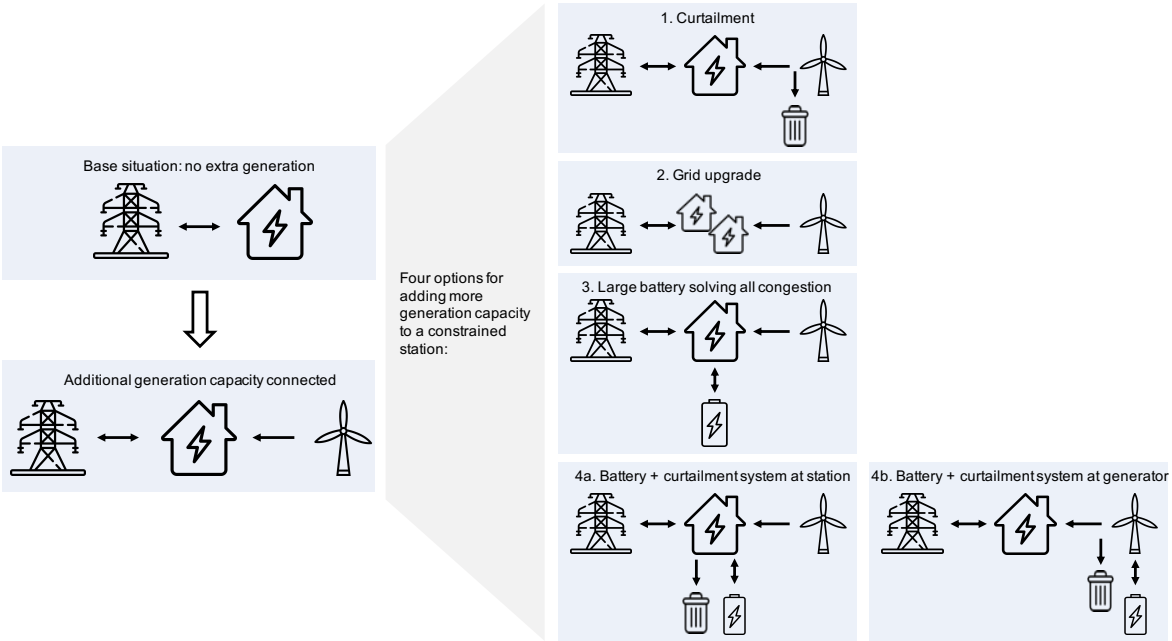


Figure 3-2: Diagram of the different scenarios available for integrating additional renewable generation in an already constrained grid.

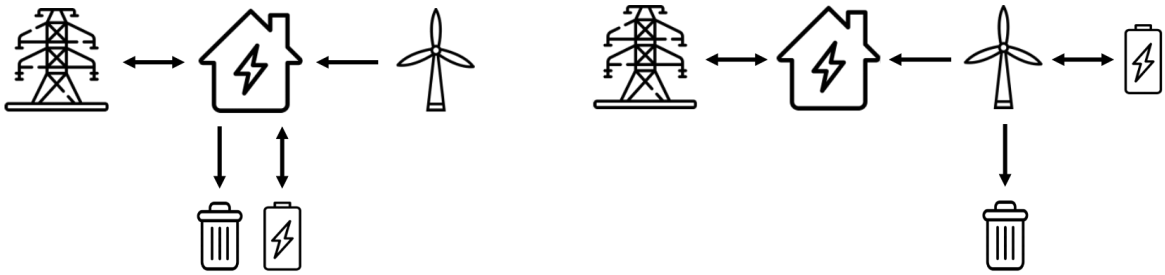
In the upper-left part of figure 6-1, the base situation is depicted: this is the steady-state situation of the studied part of the regional power network, with an MV station connected to higher voltage levels. At the MV station, all generator and consumer loads are combined. If there is more power demand than supply, power is demanded from the HV network connection and transformed down to the MV level. On the other hand, if there is more power supply than demand, the reverse happens, and power is delivered to the HV network.

In the lower-left part of figure 6-1, additional renewable generation capacity is connected to the MV station. This causes congestion to occur at the station, and the network operator will need to find a solution for the congestion. The four available solutions are depicted on the right side of the figure. The four solutions work as follows:

1. **Curtailment**: during times where the additional generator causes the MV station to overload, the network operator curtails the additional generator.
2. **Grid upgrade**: the network operator increases the network capacity to accommodate the additional renewable generator fully.
3. **A large battery solving all congestion**: a battery system is added to the MV station at a size that enables the battery system to resolve all moments of overload. The battery charges during moments of excess generation and discharges at times when there is available network capacity.
4. **A battery + curtailment system**: this is a combination of the first and third solutions. A smaller-sized battery is used in combination with curtailment to resolve all moments of station overload. This system can be located either at the MV station or at the generator site.

The difference between solutions 4a and 4b from figure 6-1 is crucial for this thesis. When adding a battery to a regional power system, there are various options for the location to connect the battery to the system. This thesis aims to compare the results obtained with different additions of renewable generation and different battery connection locations, together forming the system location. There are two distinct ways of adding a battery to the test system, representing a multitude of possibilities for batteries. The first one is to connect the battery directly to the substation, which is depicted in figure 3-3a. This battery can be used to balance out all loads connected to the substation but will likely have to be relatively large to have a real impact on the substation load.

The second option is to connect the battery at the same point as one of the connected generators or consumers. This battery can only charge from the generation delivered by the renewable generator. With increasing amounts of renewable generation, adding batteries to wind or solar farms has gained more attention. This option is depicted in figure 3-3b.



(a) Battery connected at generator **(b)** Battery connected at station

Figure 3-3: Two options for connecting a battery + curtailment system to the regional power network.

The first two solutions, curtailment and grid upgrades, are fairly straightforward to assess: their implementation and resulting value for the network operator will be analysed in chapter 6. For the solutions including a battery system, their dispatch schedule will have to be defined. The different models developed to dispatch the battery systems will be described in the next chapter.

Chapter 4

Dispatch of the battery system

This chapter will explain the three models that were developed to dispatch the different battery systems. First, a simple model governing a large battery solving all congestion is described. Second, models used to optimally operate the battery + curtailment system for both connection locations (at the substation and at the generator) are proposed.

4-1 A large battery system to solve all congestion

The initial goal of the large battery is to reduce the peak loads on the MV station in such a way that all congestion is resolved. To check this idea for feasibility and gather some first results, a simple excel model was created to model the operation of the battery. Because the battery aims to resolve congestion caused by additional renewable generation, the battery is set to charge around the negative station capacity limit[1].

Excel input parameters
The following input parameters were used for the excel model:

- The total load on the station P_{load}, including the additional generator.
- Battery capacity V_{bat} (MWh), to be varied to solve all congestion.
- Battery power P_{batmax} (MW), to be varied to solve all congestion.
- A minimum state of charge SoC_{min} of 5% and a maximum state of charge SoC_{max} of 95%.
- A positive station capacity limit $P_{statmax}$ and a negative station capacity limit $P_{statmin}$.

[1] Conventions at network operators dictate that generated power fed into the station from the MV grid is a negative load, and power demand from the station to the MV grid a positive load.

Excel model rules

The aim of this battery is to solve all congestion on the station, resulting in zero hours where the total load on the station exceeds the station capacity limits. The generation loads added to the station will cause the station capacity limits to be exceeded. Because all congestion hours are caused by generation, it is crucial that the battery charges at the right moments. The discharging moments are less critical and follow from the charging moments. The rules followed by the excel model are included in figure 4-1. P_{load} is negative for generation loads, and positive for consumption loads. The charging and discharging limits have been set at the station capacity limit: the battery will charge if the limit is exceeded through generation, and discharge if there is capacity for extra load on the station again. All battery parameters used for the model have been included in appendix A-5.

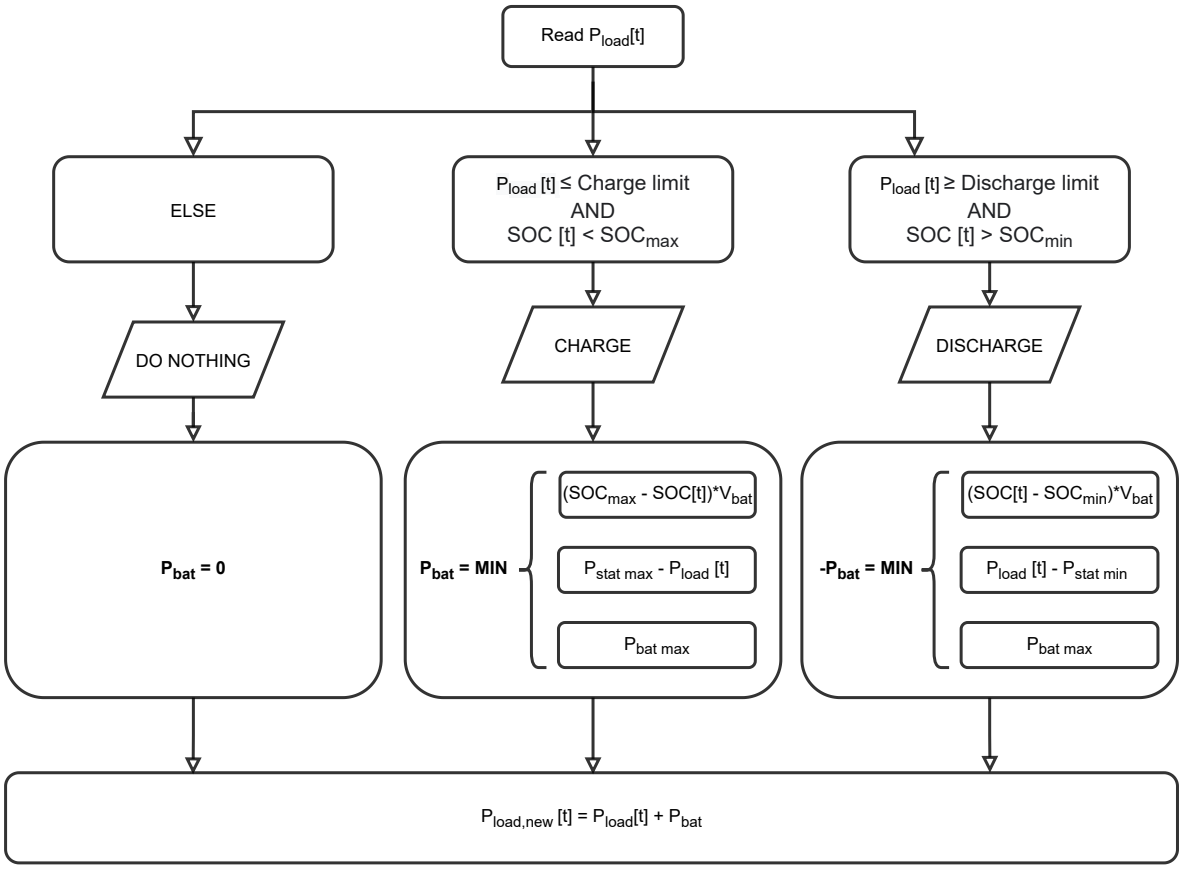


Figure 4-1: Diagram of the rule-based excel battery model flow.

4-2 Combined battery storage and curtailment

To operate the battery and curtailment system in a way that is most (economically) valuable to the DSO, the system aims to minimize curtailment costs for the DSO during the simulated year, which is 2030. When DSOs curtail generation, they have to compensate the generator for lost revenues, causing curtailment costs for the DSO. These costs depend on the volume of electricity curtailed and consist of two parts: the EPEX price at the moment of curtailment and the costs for lost subsidies. The first part varies on an hourly basis, and the second part is assumed fixed for this model. Both are expressed in € per MWh. To optimize battery usage, the curtailment costs are minimized together with the marginal costs for operating the battery: this ensures the battery will never be used if the marginal costs of using it are higher than the reduction in curtailment costs the battery will generate.

4-2-1 Battery system at located at the substation

To achieve minimal curtailment costs, it is necessary to optimize the operation of the battery during the year while adhering to the boundary conditions posed by the system. Because all variables in the optimization problem can be described by linear functions and sufficient boundary conditions are present, the optimization problem can be solved using linear programming. This is a common method for battery dispatch models, as explained in literature review section 2-2-3. Figure 4-2 shows the original situation at the substation: the substation exchanges power with the HV grid. All loads connected to the station are included in this total load on the station (not shown in the figure). Figure 4-3 shows the new situation at the substation, where a battery energy storage system and the option of curtailment have been added at the station. All other loads connected to the station are again included in the total power flows depicted.

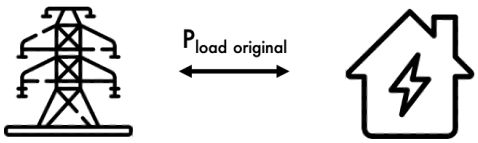


Figure 4-2: Diagram of the power flow variables in the original situation.

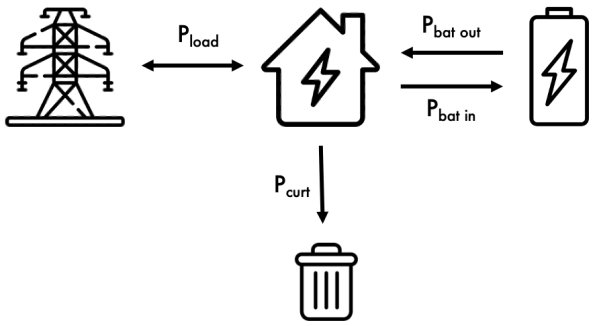


Figure 4-3: Diagram of the power flow variables used in the optimization model, with additional battery and curtailment.

Variables
The optimization variables included in the linear programming model are depicted in figure 4-3. All variables except for P_{load} are non-negative, and defined as follows:

- $P_{load,i}$ is load on the substation - HV grid connection at time step i. A positive P_{load} indicates power flowing from the HV grid to the substation, a negative P_{load} indicates power flowing from the substation to the HV grid.
- $P_{batin,i}$ is the power flowing into the battery at time step i.
- $P_{batout,i}$ is the power flowing out of the battery at time step i.
- $P_{curt,i}$ is the curtailed power at time step i.

Parameters
The parameters included in the linear programming model were set to a singular value for every run. The parameters included in the model are the following:

- V_{bat}, the capacity of the battery [MWh].
- $P_{bat,max}$, the maximum power of the battery [MW].
- η, the full-cycle efficiency of the battery [%].
- SoC_1, the initial State of Charge of the battery [%].
- SoC_{min} and SoC_{max}, the charge- and discharge limits of the battery.
- P_{limit}, the maximum capacity of the substation [MW].
- P_{cable}, the capacity limit of the cable connecting the battery to the substation.

Objective function
The goal of the optimization is to find the combination of battery operation and curtailment that results in the lowest total combination of curtailment costs and marginal costs of battery operation. Therefore, the objective function is the following:

$$\text{minimise } C_{curtailment} + MC_{Battery} \tag{4-1}$$

This section will explain the method found to calculate $C_{curtailment}$, and in section 4-2-3 the method followed to calculate the marginal costs of operating the battery is discussed.

The total costs of curtailment, $C_{curtailment}$, are defined as follows:

$$C_{curtailment} = \sum_{i=1}^{T} E_{curtailed,i} * (p_{DAM,i} + c_{curtailment}) \tag{4-2}$$

Where $E_{i,curtailed}$ equals the volume of energy curtailed at time step i in MWh, $p_{i,DAM}$ equals the Day-Ahead Market EPEX price at time step i in €/MWh, and $c_{curtailment}$ equals the

additional costs the DSO faces for curtailing generation in €/MWh. The model uses hourly data, thus every time step i equals one hour, and there are $T = 8784$ time steps in the year[2].

The volume of energy curtailed can be calculated in the following way:

$$E_{curtailed,i} = P_{curt,i} * \Delta t = \begin{cases} |P_{load,i} - P_{limit}|, & \text{if } |P_{load,i}| > P_{limit} \\ 0, & \text{otherwise} \end{cases} \tag{4-3}$$

with $P_{i,load}$ the power exchanged with the grid at time step i, P_{limit} the station capacity limit, and Δt the duration of time step i.

Constraints

The constraints included in the problem can be divided into two categories. The first are constraints on the power flows between the various elements of the system, and the second are constraints on the operation of the battery system.

Power flow constraints

The new $P_{load,i}$, including battery and curtailed loads, consists of several components, which are all depicted in figure 4-3. The first equation governing the total load on the station ensures the conservation of energy when adding batteries and curtailment to the system. For every time step i, the total load on the substation P_{load} into the grid can be described as:

$$P_{i,load} = P_{i,load,original} + P_{i,batin} - \eta * P_{i,batout} + P_{i,curt} \tag{4-4}$$

Where $P_{i,loadoriginal}$ is the original (without the battery and curtailment) power exchange with the grid at time step i, $P_{i,batin}$ is the power flowing into the battery at time step i, $P_{i,batout}$ is the power flowing out of the battery at time step i. This power is multiplied by the batteries cycle efficiency η to account for battery losses. It is important to remember that generation causes a negative P_{load}, which is why power flowing out of the battery is counted with a minus.

The aim of the second constraint is to keep the power flow from and to the grid within the station limits. This constraint has been formulated as follows:

$$|P_{load,i}| \leq P_{limit}, \ \forall i \in T \tag{4-5}$$

Additionally, there is a limit to the amount of energy that can be curtailed. To ensure the model does not curtail unnecessary large volumes of energy, there can never be more energy curtailed than the amount by which the station limit is exceeded at time step i. Also, positive (consumer) loads can never be curtailed. This constraint is formulated as follows:

$$P_{curt,i} \begin{cases} \leq |P_{load,i} - P_{limit}|, & \text{if } P_{load,i} < 0 \\ = 0, & \text{otherwise} \end{cases}, \forall i \in T \tag{4-6}$$

[2]The base year was 2020, which is a leap year, adding 24 hours to the base number of 8760 hours for one year. For the profiles that did not have 2020 as a base year, the first of March was included twice to get an equal number of hours.

Battery constraints
There are three major constraints on the battery: power constraints, state of charge (SoC) constraints and cable constraints.

The state of charge (SoC) SoC_i at time step i is defined as follows:

$$SoC_i = SoC_{i-1} + \frac{P_{batin,i} - P_{batout,i}}{V_{Bat}} \tag{4-7}$$

The initial state of charge, SoC_1 has been set at 50%.

To operate the battery optimally, the SoC should remain within certain boundary values. Most types of batteries do not fare well when fully charged or fully discharged often. To prevent battery capacity fading as a result of that, constraints are imposed on the state of charge:

$$SoC_{min} \leq SoC_i \leq SoC_{max}, \forall i \in T \tag{4-8}$$

The second set of constraints on the battery operation is the power constraint. The battery can never charge or discharge more than its power rating P_{batmax} during one time step. This constraints can be described as:

$$P_{batout,i} \leq P_{batmax}, P_{batin,i} \leq P_{batmax}, \forall i \in T \tag{4-9}$$

The last set of constraints on the battery results from the cable connecting the battery to the substation. This cable has a certain capacity limit, P_{cable}, which is the maximum power it can transport during time step i. The constraint ensuing from this is the following:

$$|P_{batout,i} - P_{batin,i}| \leq P_{cable}, \forall i \in T \tag{4-10}$$

For this model, P_{cable} has been set at 10 MW, as this is the largest load a DSO will connect directly to a substation (Liander, 2021c).

4-2-2 Battery system located at the generator

To connect the battery and curtailment system only to the selected additional renewable energy source, minor alterations have to be made to the linear optimization problem. The goal of the optimization remains the same: to minimize the curtailment costs and marginal battery operation costs over a year by operating the battery optimally while ensuring the power flows to and from the HV grid are within the station's capacity limits. However, in this case, the battery and curtailment options are only available to use on the power generated by the connected renewable energy source. It is assumed the battery and curtailment system does have knowledge of the total station load at all times.

Variables
The optimization variables included in the linear programming model are depicted in figure 4-5 and defined as follows:

- $P_{load,i}$ is the total load on the substation at time step i. A positive P_{load} indicates power flowing from the HV grid to the substation, and a negative P_{load} indicates power flowing from the substation to the HV grid.

- $P_{gen,i}$ is the power flowing from the generator system to the substation at time i. A negative value for P_{gen} indicates power flowing from the generator system to the substation, and only negative values for P_{gen} are allowed to retain a one-directional power flow.
- $P_{batin,i}$ is the power flowing into the battery at time step i.
- $P_{batout,i}$ is the power flowing out of the battery at time step i.
- $P_{curt,i}$ is the curtailed power from the generator at time step i.

Parameters
The parameters used in the model for placing the battery system at the generator are equal to the parameters for the battery system at the substation described in the previous section.

Constraints
The constraints can again be divided into power flow constraints and battery system constraints. The battery system constraints are equal to the battery system constraints described in section 4-2-1. The power flow constraints are subject to some changes because of the added renewable generator power flow and described below.

Power flow constraints
For every time step i, the total load on the substation is equal to the sum of the total load on the substation without the renewable generator present, and the load flowing from the renewable generator to the substation. This relationship is presented in figure 4-4 and described by:

$$P_{load,i} = P_{originalload,noRE,i} + P_{gen,i} \tag{4-11}$$

With $P_{originalload,noRE}$ the original load on the station without the additional renewable generation capacity. This load is depicted in figure 4-4.

The power flowing from the generator system to the substation can then be described by:

$$P_{gen,i} = P_{gen,original,i} - \eta * P_{batout,i} + P_{batin,i} + P_{curt,i} \tag{4-12}$$

With $P_{gen,original}$ the original power flow from the generator to the substation, without the battery and curtailment system present. This flow is depicted in figure 4-4.

To ensure total power before and after the optimization are equal, the following constraint must be satisfied:

$$P_{load,original,i} = P_{load} + \eta * P_{batout,i} - P_{batin,i} - P_{curt,i} \tag{4-13}$$

To ensure that there is no more power curtailed than generated at every time step, P_{curt} is capped by the original production of the generator, $P_{genoriginal}$:

$$P_{curt,i} \leq P_{genoriginal,i}, \forall i \in T \tag{4-14}$$

Additionally, to ensure the model does not curtail unnecessary large volumes of energy, there can never be more energy curtailed than the amount by which the station limit is exceeded at time step i:

$$P_{curt,i} \begin{cases} \leq |P_{load,i} - P_{limit}|, & \text{if } P_{load,i} < 0 \\ = 0, & \text{otherwise} \end{cases}, \forall i \in T \tag{4-15}$$

Finally, the total power flowing from the generator system to the substation is limited by the capacity of the cable connecting the two systems, as described by:

$$|P_{gen,i}| \leq P_{cable}, \forall i \in T \tag{4-16}$$

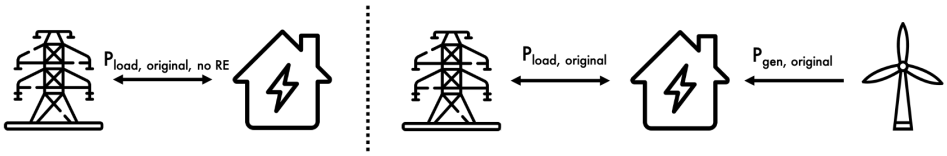


Figure 4-4: Diagram of the power flow variables in both reference situations. On the left, the situation without additional renewable generation. On the right, the situation including additional renewable generation.

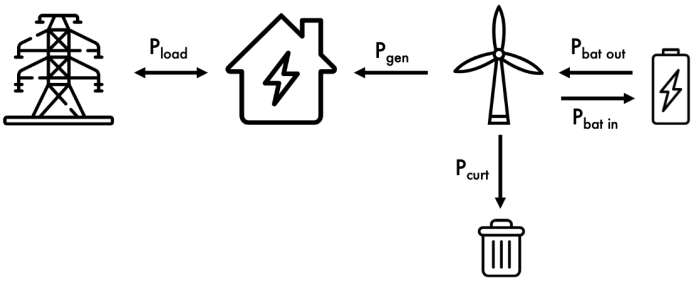


Figure 4-5: Diagram of the power flow variables used in the optimization model, with additional battery and curtailment placed at the generator side.

4-2-3 Marginal costs of battery operation

To ensure the battery will never operate when its marginal costs of operation are higher than the reduction in curtailment costs it can deliver, the model was set up to minimize the combination of curtailment cost and marginal costs of battery operation. The marginal costs for operating the battery system were modelled in accordance with (Schimpe et al., 2018). The marginal costs consist of the costs for energy conversion losses and battery degradation costs and are defined as follows:

$$MC_{Battery} = MC_{Conversion,charging} + MC_{Conversion,discharging} + MC_{degradation} \tag{4-17}$$

The costs of conversion losses are the result of the amount of energy lost during the conversion and the electricity price at that moment. For charging, these can be evaluated as:

$$MC_{Conversion,charging} = (1 - \eta_{Charging}) * P_{batin,i} * p_{DAM,i} \tag{4-18}$$

For discharging, the relation is similar:

$$MC_{Conversion,discharging} = (1 - \eta_{discharging}) * P_{batout,i} * p_{DAM,i} \tag{4-19}$$

Determining the battery degradation marginal costs is a bit more complex. Several degradation mechanisms occur during battery operations. The two main categories are loss of lithium inventory, which results in less cyclable lithium being available, and loss of active material, which results in less availability of other components of the reaction (Woody, Arbabzadeh, Lewis, Keoleian, & Stefanopoulou, 2020). The three variables that have the largest impact on Lithium-Ion battery degradation are operating temperature, state-of-charge of the system, and the system's C-rate. Most lithium-ion batteries degrade much slower when operating around room temperature, when the time spent on high SoC levels is minimized and when they have a lower C-Rate.

In general, battery systems are considered to be at their end of life when their capacity has faded by 20% relative to their original capacity (Woody et al., 2020), (Vetter et al., 2005), (Schimpe et al., 2018). This amount of degradation is called the capacity fade limit. During each cycle, the battery gets closer to its capacity fade limit. The number of full cycles the battery has gone through when it reaches its capacity fade limit is called the battery cycling life. For determining the marginal costs of battery degradation, first the share of capacity fade that occurs during one cycle must be determined. This capacity fade per cycle, or $q_{capfade,cycle}$ can be calculated as:

$$q_{fade,cycle} = \frac{Q_{capfade,limit} * V_{max}}{L_{cycle}} \tag{4-20}$$

With $Q_{capfade,limit}$ the capacity fade limit, V_{max} the battery's original capacity and L_{cycle} the cycling life of the battery.

Then, the marginal costs of battery degradation can be calculated as follows:

$$MAC_{degradation} = C_{capacity} * q_{fade,cycle} \tag{4-21}$$

with $C_{capacity}$ the costs of battery capacity in € per MWh.

Chapter 5

Case study of an MV substation: technical analysis

In this chapter, a case study will be developed for using the models presented in the previous chapter. First, criteria for the MV substation used for the case study will be described. Second, possible substations will be analysed, and one will be selected. Subsequently, profiles will be developed for the increased electrification and additional renewable generation at this substation in 2030. Finally, the electrification and generation profiles will be used to construct the total load on the substation in 2030, and to implement the developed models for different generation scenarios.

5-1 Selection of a case study station

In the broad selection of possible substations to use for the case study, the following aspects were considered:

- The substation needs to be at risk for congestion; connecting an additional generator will cause overloads.
- The substation has only elements connected to it that can be regarded as 'normal' in the Dutch regional power system.
- Measurements of the substations and connecting fields are available for an entire year.

During the broad search for a test system, multiple data maps were used, including:

- Congestion maps from Liander (Liander, 2021a)
- A map of all active wind turbines in the Netherlands (Bosch & van Rijn, n.d.)

- A map of all SDE subsidised renewable energy projects currently under management (Rijksdienst voor Ondernemend Nederland (RVO), 2021)
- A map of all high-voltage lines and HV/MV substations in the Netherlands (TenneT TSO BV, n.d.)

Using the information gathered from the maps, data for relevant substation loads was requested from Liander. This resulted in data for three different MV substations. The degree to which they satisfy the proposed criteria has been included in table 5-1.

Table 5-1: The different substations considered for the case study, and their compliance with the criteria

Substation	Congestion risk	Representative elements connected	Data availability
Dronten	High	No, very large (23 MW) wind farm connected	Yes
Waalsprong	High	Yes, except for flexmarket project	Yes
Wommels	High	Yes	Limited

By combining information from these sources and in close discussion with Liander, one site was selected as the most promising test case: substation Waalsprong. The other two substations were eliminated for two different reasons. At substation Dronten, a 23.2 MW wind farm was connected, which is exceptionally large for a generator connected to an MV substation and therefore not a representative test case. For substation Wommels, only the absolute value of the load on the substation was available, and not the direction of the load.

5-1-1 Substation Waalsprong

The considered station in Waalsprong is a distribution station, which is a substation operating at one main voltage level where the incoming fields are split over a multitude of outgoing MV fields, at a constant voltage. Distribution stations are often found close to HV/MV substations. Distribution station Waalsprong operates at 10 kV and is connected to substation Elst, which transforms power from 150 kV to 10 kV.

In figure 5-1, a network overview of distribution station Waalsprong and all connected fields is depicted. The station is connected to an HV/MV power supply from 150/10 kV substation Elst in the left of the figure, through KA14 and KA15. This substation has a limited feeding capacity of 10.5 MVA at N-1 redundancy.

Sufficient data points are available for this distribution station because Liander is testing new solutions for power systems with a high share of solar PV and wind there. The Liander 'Flexmarket' project is active in the field connected to KA05. This field is connected to multiple MV consumers, including a Lidl supermarket with a 1 MW/1 MWh battery. The battery acts on market prices, which causes the battery to operate on very short ($<$ 15 mins) time scales. In total, the size of the Flexmarket is limited at 0.8 MVA and thus reasonably small compared to the total size (10.5 MVA) of this station.

Production-wise, field KA04 connects to a 10 MW wind farm. The generation from this wind farm in 2020 has been plotted in figure A-1 in appendix A. It is likely that there is also a number of smaller producers (such as residential-scale solar PV) connected to this substation,

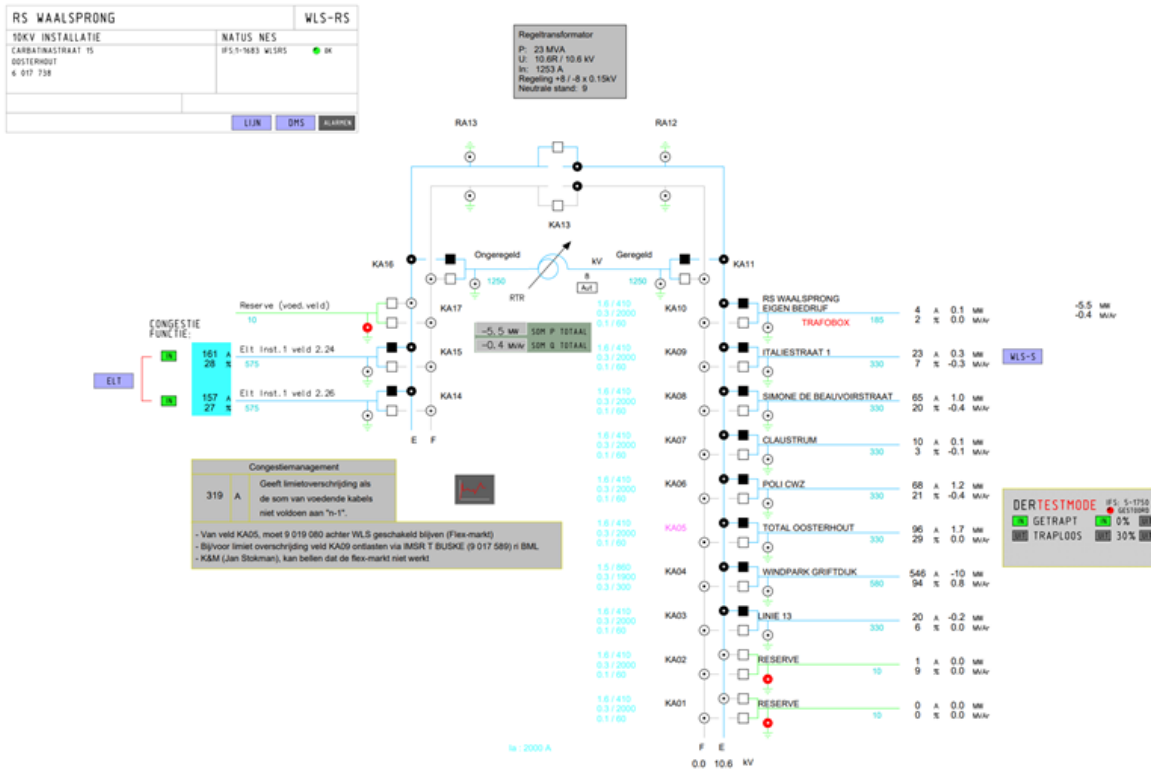


Figure 5-1: Network overview of switching station Waalsprong and all connected fields. Obtained from (Liander, 2021c).

which are connected to the LV network branches not included in this figure. Effects of those branches do propagate to the connected MV network.

Looking at the consumption side, 6559 end-users are connected to the network extending from distribution station Waalsprong. Table 5-2 gives an overview of these end-user connections. These connections are made up of 6394 small-scale end-user connections and 165 large-scale end-user connections.

Table 5-2: Overview of total end-user connections from distribution station Waalsprong. Data from (Liander, 2021c).

Total end-user connections	Small-scale	Large-scale
6559	6394	165

The combination of connections to distribution station Waalsprong results in a total load on the distribution station transformer. In figure 5-2, the average hourly load on distribution station Waalsprong is plotted for 2020. From this plot, it can be concluded that the transformer capacity was not exceeded in 2020, but the system was operating close to its limits on a few occasions. Nevertheless, connecting more end-users or producers could result in loads that exceed the transformer capacity in the future.

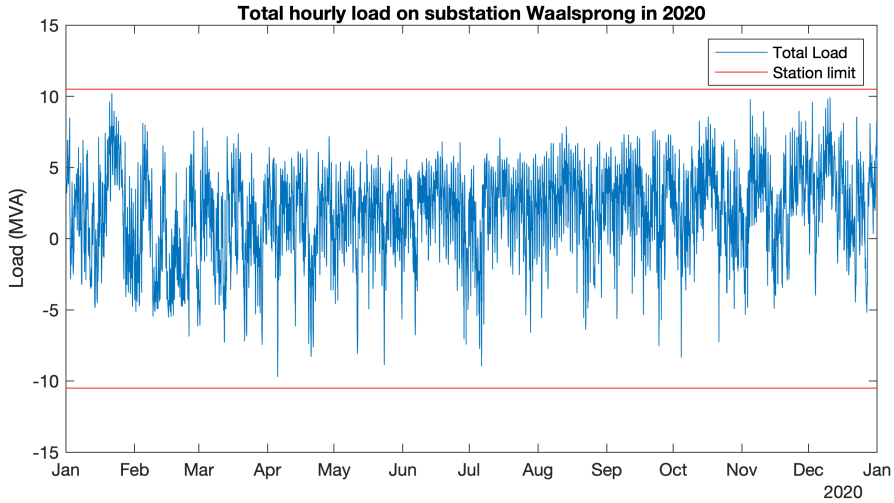


Figure 5-2: Plot of the hourly load on station Waalsprong in 2020. Data from (Liander, 2021c).

5-2 The station in 2030

By 2030, two effects will have occurred at station Waalspong as a result of the energy transition. Firstly, consumer loads will increase due to electrification. This effect will be explained and modelled in the next section. Secondly, renewable generation on the regional network and substation will increase. This effect will be explained and modelled in section 5-2-2.

5-2-1 Electrification at the station in 2030

As described in section 3-2, by 2030, part of the end-users' energy use will be electrified, increasing the load on the considered station. Because the largest share of connections is for regular consumers, and industrial electrification profiles are highly specific, this thesis only assumes electrification for the connected consumers. The two elements with presumably the most significant impact are considered: heat pumps and electric vehicles.

Heat pumps

According to a previous CE Delft Study, the share of homes heated by (hybrid) heat pumps will increase from 2.4% in 2020 to 15% in 2030 if the policies from the Climate Agreement are executed (CE Delft, 2020). This effect can be seen in table 5-3.

To assess the effect of heat pumps on substation Waalsprong, it is crucial to know how many dwellings are connected to the station. Unfortunately, only information on the size of the connection (regular user or large-scale user) was available. Therefore, an estimation has been made based on the ratio of dwellings and non-residential buildings in Waalsprong, included in table 5-4.

Assuming the increase in heat pumps in Waalsprong will happen at the same speed as in all of the Netherlands, approximately an additional 10% of the dwellings connected to the station

Table 5-3: The projected developments in heating technology in Dutch dwellings 2020 - 2030. Numbers in percentage of total heating technology and absolute count. Adapted from (CE Delft, 2020).

Heating technology	Current share	Projected share - 2030
Heat pumps (all-electric)	1.6% (123,000)	11% (923,000)
Heat pumps (hybrid)	0.8% (61,000)	4% (344,000)
District heating	5.6% (437,600)	13% (1,139,000)
Gas central heating	92% (7,177,000)	72% (6,104,000)

Table 5-4: Dwellings and non-residential building stock for Waalsprong (Municipality of Nijmegen). The number of small-scale end-user connections that are dwellings has been estimated based on the share dwellings in these municipalities. (Centraal Bureau voor de Statistiek (CBS), 2020b), (Liander, 2021c).

Parameter	Waalsprong value
Total dwellings and non-residential stock	93,428
Dwellings	82,317 (88%)
Small-scale connections	6394
Est. connected dwellings	5624
Additional heat pumps connected 2030	562

will be equipped with heat pumps by 2030. The totals of this estimate can be regarded in table 5-4.

To simulate the load of the additional heat pumps, CE Delft's heat pump profiles were used (CE Delft, 2020). There are different heat pump profiles for different situations. Firstly, there are profiles for all-electric heat pumps and for hybrid heat pumps, which are a combination of the traditional gas-powered heating system and heat pump technology. Secondly, there are profiles for three levels of insulation: low, average and high. Thirdly, there are profiles for four types of dwellings: detached houses, semi-detached houses, apartments and townhouses.

For the sake of this study, all dwellings were considered to have average insulation. For dwelling type, average numbers from all of the Netherlands were used, which were collected in a survey in 2015 (Centraal Bureau voor de Statistiek (CBS), 2015). The division of dwelling types is depicted in figure 5-3.

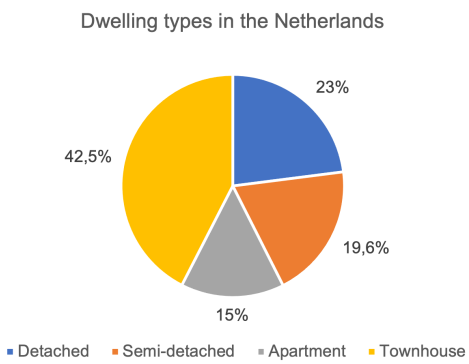


Figure 5-3: Average division of dwelling types in the Netherlands in 2015 (Centraal Bureau voor de Statistiek (CBS), 2015).

Using this division of dwelling types, assuming average insulation and an average temperature year (2015), heat pump load profiles were created for Waalsprong. Using 2015 instead of 2020 introduces some uncertainty in the simultaneity of loads, but this profile was available. The resulting heat pump load in Waalsprong in 2030 is depicted in figure 5-4. The peak load from heat pumps in Waalsprong is 1.4 MW, and occurs on the 7th of February at 6:00.

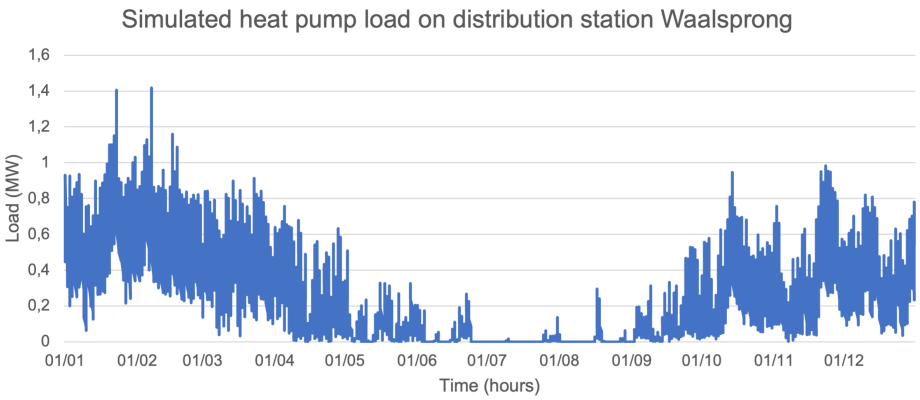


Figure 5-4: Generated load profile for heat pumps connected to dwellings in the service region of distribution station Waalsprong in 2030. Profiles adapted from (CE Delft, 2020).

Electric vehicles

The second load that will increase by 2030 due to electrification is electric vehicle charging. CE Delft has estimated that by 2030, an additional 4 million MWh will be demanded in the Netherlands for the charging of electric vehicles (CE Delft, 2020). To translate the effect of this to station Waalsprong, it was assumed the additional power demand scales with the share of the total passenger cars in the region compared to all of the Netherlands.

Table 5-5: Total passenger car fleet for the Netherlands and the municipality of Nijmegen, which holds 0.79% of the national fleet. Data from (Centraal Bureau voor de Statistiek (CBS), 2020a) and (CE Delft, 2020).

	Netherlands	**Nijmegen**
Total passenger cars	8,677,911	68,503 (0.79%)
2030 additional EV energy demand (MWh)	4,083,698	32,236
2030 additional EV demand on station (MWh)	-	221

The last line in table 5-5 accounts for the fact that not all of the municipality is serviced by the substation considered here. The share of EV load connected to station Waalsprong was estimated using the ratio of the dwellings connected to the station and the total dwellings in the municipality.

Because EVs move around and charge in different places, there are multiple ways the EV load connects to the power system. A previous study by CE Delft analysed how the different charging loads will most likely be divided over charging at home, charging in public places, charging at workplaces and using fast chargers. These different charging points have different

load profiles, the sum of which is the total load on the test station. It is assumed that the amount of energy charged by visiting EVs from other regions is roughly equal to the amount of charging local EVs do in other regions. In figure 5-6, the resulting charging load on substation Waalsprong is plotted for the first week of November.

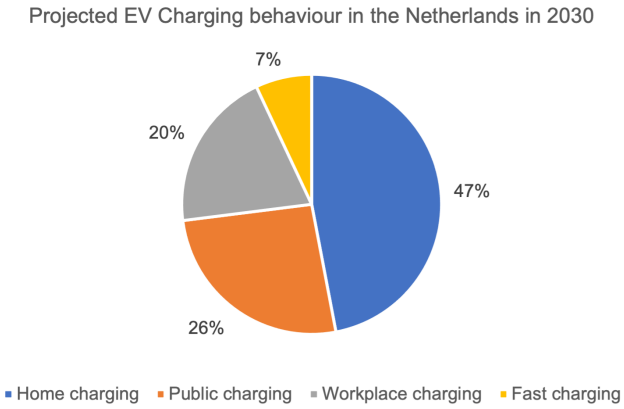


Figure 5-5: Projected division of energy over EV charging types in the Netherlands in 2030. Data from (Wolbertus & van den Hoed, 2020) and (CE Delft, 2020).

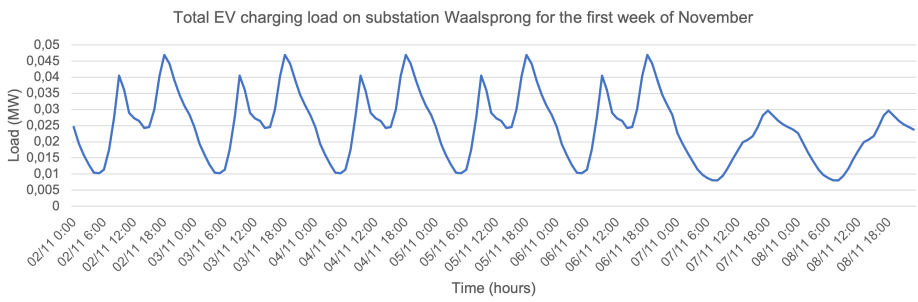


Figure 5-6: One-week sample of generated load profile for EV charging loads in the region of substation Waalsprong. Profile adapted from (CE Delft, 2020).

5-2-2 Additional generation scenarios for 2030

For power generation in the Dutch MV grid in 2030, the two dominant generation techniques are solar PV and wind turbines. The case study will be based on the two dominant generation techniques, which will be used to generate four different generation scenarios:

1. A wind generator of 9 MW
2. A solar generator of 12.85 MWp, connected at 70%, resulting in 9 MW generation
3. A solar generator of 12.85 MWp connected at 100% of its peak capacity
4. A combined wind and solar generator, both of 4.5 MW

This section will explain why these scenarios were selected and how each of the four generation scenarios was set up.

Wind generator

For determining the size of the wind farm, two elements were taken into consideration: the congestion caused by the wind farm and the available turbine sizes. In order to see a significant congestion effect in the case study, the size of the wind farm would be set at 10 MW, which is equal to the maximum generator capacity connected to MV substations by most DSOs. However, wind farms are not as easy to develop at a desired size as solar farms are, as wind turbines often come in standard sizes. As can be found in multiple RESses, the most common wind turbine for onshore power generation in 2030 is expected to be one with a 3 MW capacity (Noord-Hollandse Energie Regio, 2020b), (Liander, 2021c). Therefore, instead of using the 10 MW connected wind farm, a 9 MW wind farm was simulated. This wind farm was modelled using measured generation data from Liander in Waalsprong, scaled linearly to a 9 MW capacity. In appendix A-1, figures A-2 and A-3 have been included. Figure A-2 shows the power generated by the wind farm in 2020. The generation is plotted as negative because that is the convention for network operators. Figure A-3 shows the wind farm production during an average week. Figure 5-7 shows the wind farm production during one of the most extreme weeks of the year in terms of production. The peak in wind production occurs on February 10th, 15:00 and has a value of -8.69 MVA. This figure highlights an effect seen around many of the peak production moments in the year: peaks occur in series with only minor decreases between them. These moments are caused by storms lasting several days.

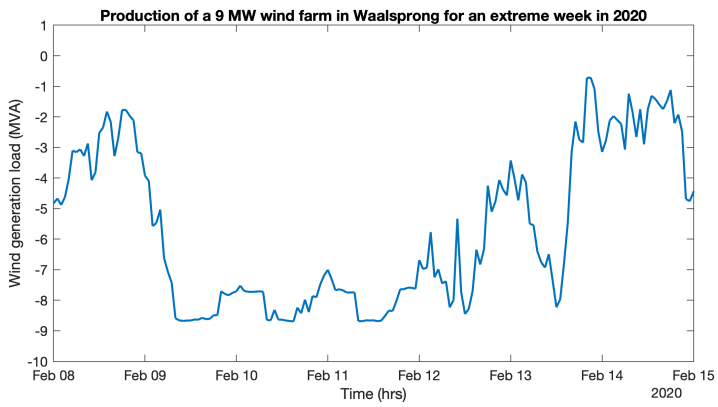


Figure 5-7: Generated wind production profile for a 9 MW wind farm in Waalsprong in an extreme production week in 2020. Generated with data from (Liander, 2021c).

Solar generators

At the moment, solar PV systems of varying types and sizes are present in the Dutch power system. In the past, smaller-scale systems were the prevalent type, but larger-scale solar systems have been on the rise over the last few years. This effect can be witnessed in figure 5-8, which shows the growing number of solar PV projects in the SDE subsidy in the 5 - 25 MWp capacity range. The final number for 2020 will most likely be higher, as only one of the two subsidy rounds for 2020 has been published.

In order to see a significant congestion effect within the case study and to make this scenario comparable to the wind scenario, the desired output size of the solar generator is set at 9 MW.

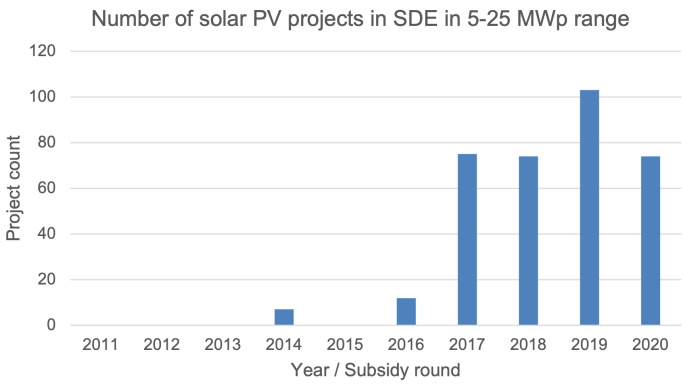


Figure 5-8: Number of solar PV projects within 5 - 25 MWp capacity range in SDE subsidy scheme. The number for 2020 has not been finalised yet, as only the first of the two subsidy rounds planned for 2020 has been allocated. Data from (Rijksdienst voor Ondernemend Nederland (RVO), 2021).

However, because of congestion risk and inverter costs, solar farms are most often connected at 70% of their nominal capacity (Holland Solar & Netbeheer Nederland, 2020). This habit is called 'overplanting'. By overplanting, solar generators do not incur high connection and inverter costs for their peak in production, which they almost never reach[1] (Holland Solar & Netbeheer Nederland, 2020). To ensure the 9 MW output, the first solar generator is overplanted at 12.85 MWp[2]. The second solar generator scenario is connected at full capacity to enable a comparison between the two.

The solar profiles used have been created in three steps. First, hourly weather data for Waalsprong in 2020 was requested from weather service Solcast (Solcast, 2021). The hourly data set contained global horizontal irradiance (W/m^2), diffuse horizontal irradiance (W/m^2), ambient temperature ($°C$) and wind velocity (m/s). Solcast uses satellite weather data with a high spatial resolution of 1-2 km.

Second, the irradiance data was fed into PV Syst, a software package specialised in the simulation of PV systems (PVSyst SA, 2021). The three most significant parameters for this simulation were the PV System's azimuth, tilt, and PV panel type. A south-facing azimuth (180°) and an inclination of 37° were chosen, as these are the angles that provide the highest power output for solar panels in the Netherlands (Isabella, Klement, Schepel, & Tozzi, 2021). For the panel, a generic 440 Wp high-efficiency mono-crystalline type was selected. The choice for relatively high efficiency and power output was made with regards to the fact that in 2030, solar panels' efficiency and output will have likely gone up. Thirdly, the output from PV Syst was used to create two solar profiles: first the regular solar profile, and then the overplanted solar profile, connected at 70% of its maximum capacity.

Figure A-4 in appendix A-1 shows the power generated by the solar generator connected at 70% in 2020. Figure A-6 shows the same plot but for the solar generator connected at full capacity. For both solar generators, the peak in production occurs on May 28th, 12:00. The peak values for the system connected at 70% and the fully connected system are respectively -9.00 MVA and -10.93 MVA. Figure 5-9 shows the 100%-connected solar generation during an

[1] According to the covenant, producers reach the upper 30% only approximately 3% of the year.
[2] Because 70% of 12.85 MW results in 9 MW production.

average week. The shape of the plot clearly shows the daily solar cycle: peaks in production occur in the middle of the day, and production goes to zero between peaks. The same is visible for the 70%-connected variant in figure A-5, however, the peaks of this generation profile have been flattened at 9 MW. Figure 5-10 shows the 70%-connected solar PV plant production during one of the most extreme weeks of the year in terms of production: the capacity cutoff limit of 9 MW is reached almost every day of the week.

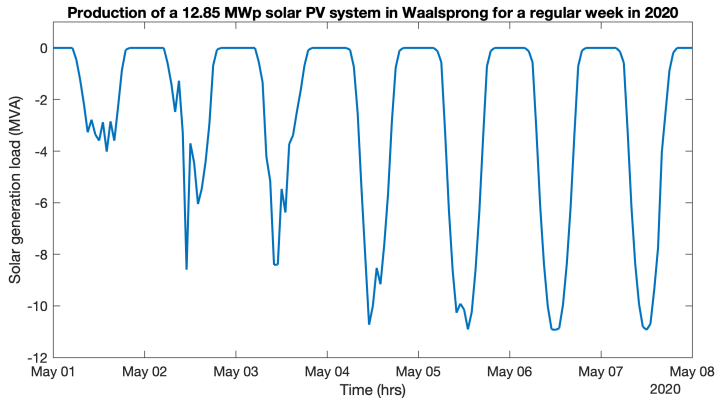


Figure 5-9: Generated solar PV production profile for a 12.85 MW solar generator in Waalsprong in a regular production week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

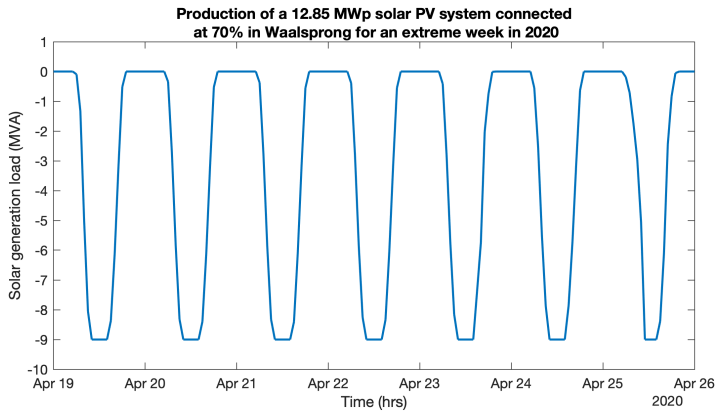


Figure 5-10: Generated solar PV production profile for a 12.85 MW solar generator connected at 70% in Waalsprong in an extreme production week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

Combined wind/solar system

The last generation scenario considered is a combined wind and solar generator. The practice of connecting a wind and solar generator using the same connection point is called 'cable pooling', and it is becoming increasingly popular as a solution to the limited available connection capacity for generators in the Netherlands. The main reason for this lies in the asynchronicity of wind and solar production: because solar and wind production often show peak production at different times, the available connection capacity can be used more efficiently. However, if peak production coincides for the generators, a lot of their power will have to be curtailed (Netbeheer Nederland, 2020).

The combined system was set at 4.5 MW/4.5 MWp wind/solar generation to make this scenario comparable to the other 9 MW scenarios. The generator profiles were scaled linearly to 4.5 MW, and their hourly values were summed to get the final hourly production. Figure A-8 in appendix A-1 shows the power generated by the combined 4.5 MW/4.5 MWp wind and solar generator in 2020. Figure A-9 shows the hourly generation of the combined system for a regular week in 2020. The peak in production occurs on March 12th, 12:00 and has a value of -7.92 MVA. Figure 5-11 shows a week of extreme generation for the combined system. This combined generation plot still shows the typical daily solar production cycle and clear features of the more stochastic wind generation.

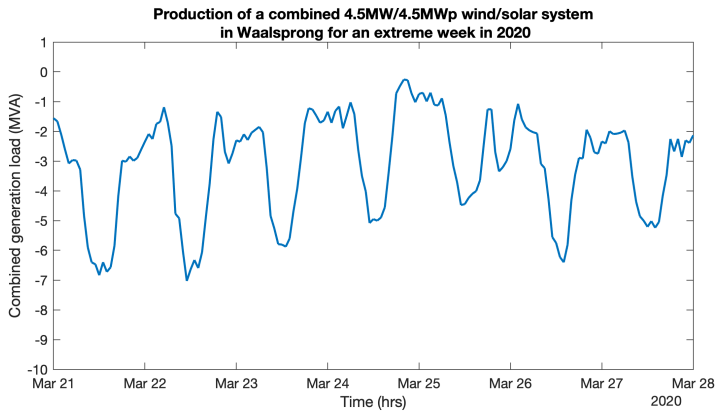


Figure 5-11: Generated solar PV production profile for a combined 4.5 MW/4.5 MWp wind/solar generator in Waalsprong in an extreme production week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

5-3 Waalsprong - total load profiles for simulation

By combining the additional generation scenarios and electrification load profiles at substation Waalsprong, the total loads on the substation for the different scenarios have been generated. Figures 5-12, 5-13, 5-14, and 5-15 show the simulated total load on substation Waalsprong in 2030, with electrification and the four additional generation scenarios.

Table 5-6: Reference load values for the original station load, the station load including electrification, the station load with 9 MW wind added, the station load with 12.85 MWp solar connected at 70% added, the station load with 12.85 MWp solar added and the 4.5MW/4.5MWp wind/solar combination. All loads with a generator are including electrification for 2030.

	Load 2020	**+Electrif.**	**+Wind**	**+Solar 70%**	**+Solar 100%**	**+Wind/Solar**
Avg. abs load (MVA)	2.95	3.08	4.05	3.75	3.80	3.54
Max load (MVA)	10.21	10.47	11.9	11.34	11.34	11.37
Min load (MVA)	-9.72	-9.62	-17.40	-18.62	-19.47	-16.96
Hours over limit	0	0	412	198	277	105
Avg. MWh over limit	0	0	5.87	5.60	6.09	5.44
Max. MWh over limit	0	0	41.94	33.93	41.79	22.91
Total MWh over limit	0	0	657.58	391.68	566.25	184.91
Curtailment costs (k€)	0	0	83.7	34.2	55.2	15.7

Table 5-6 contains characteristic values for the final load series. The table clearly shows that adding extra generation capacity leads to more congestion. This congestion can be measured both in the number of hours the load on the station exceeds the station limits, in the total volume of energy (MWhs) exceeding the station limits or in curtailment costs. The row *Hours over limit* demonstrates the number of hours the station's capacity limits are exceeded for every generation scenario. The row *Avg. MWh over limit* indicates the average volume of energy that exceeds the station's boundaries, per moment of congestion. The row *Max. MWh over limit* indicates the largest volume of energy exceeding the limits, occurring in subsequent hours. The row *Total MWh over limit* indicates how much energy in total exceeds the station's limits.

From the table it is clear that adding wind generation to the station, the congestion increases the most, both in hours and in volume. This is most likely because there is already quite some wind (10 MW) connected to this substation, which will peak simultaneously with the additional wind production. Both solar generators seem to cause less congestion. Adding combined wind and solar generation has an interesting effect: it creates less congestion than only wind or solar generation. This is due to the asynchronicity in the peak production of wind and solar. In appendix A-2, overload-duration curves are included for substation Waalsprong. These curves show the number of hours with an excess load on the station during the year. From the overshoot-duration curves as well as table 5-6, it is clear that the excess load on station Waalsprong is never more than 10 MVA. Therefore, a 10 MW battery would would always be able to solve congestion at the station - if the battery's energy capacity is sufficient for multiple congested hours in a row.

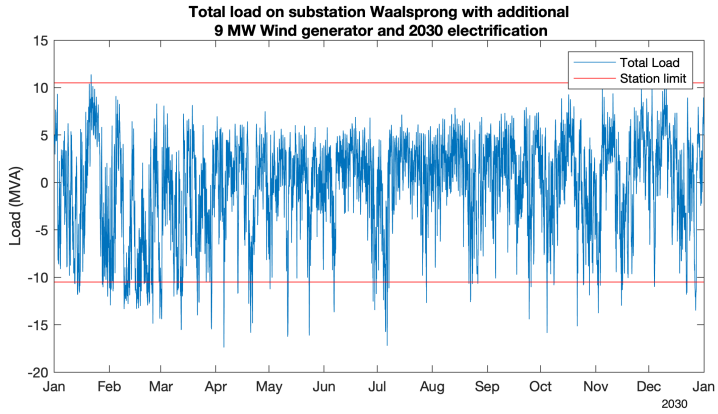


Figure 5-12: Total load on substation Waalsprong with estimated 2030 electrification and an additional 9 MW wind generator.

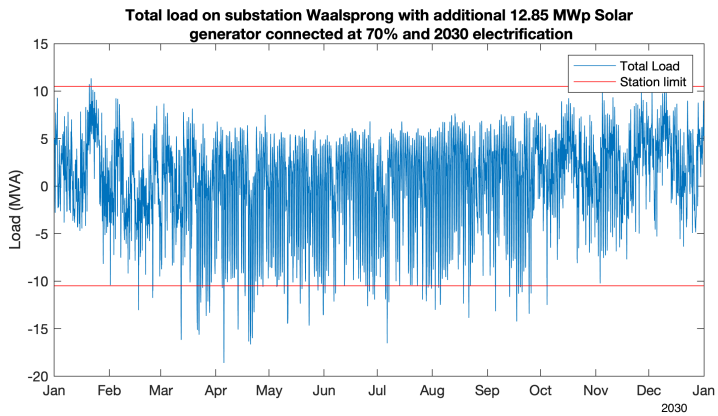


Figure 5-13: Total load on substation Waalsprong with estimated 2030 electrification and an additional 12.85 MWp Solar PV generator, connected at 70% of its capacity (resulting in 9 MW generation).

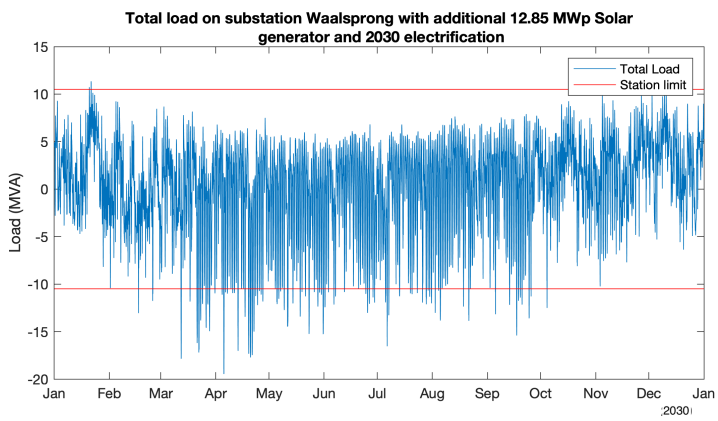


Figure 5-14: Total load on substation Waalsprong with estimated 2030 electrification and an additional 12.85 MWp Solar PV generator.

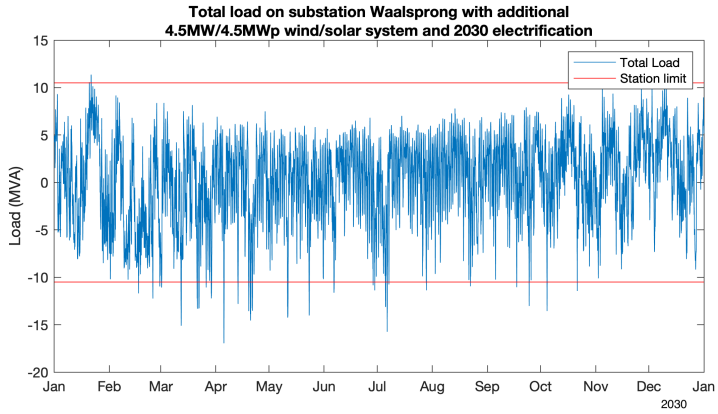


Figure 5-15: Total load on substation Waalsprong with estimated 2030 electrification and an additional combined 4.5MW/4.5MWp wind/solar generator.

5-4 Electricity prices

In addition to the generator and substation loads, one other element will play a significant role in determining the value of a battery system in the MV grid: electricity prices. The battery will likely charge during peak load moments, with low prices, and discharge during higher-priced moments. In this way, the battery will realise an operating[3] profit. The prices used in this thesis are the Day Ahead Market (DAM) EPEX prices, as explained in section 2-1-1.

Electricity prices in 2030

CE Delft has previously created the PowerFlex model, which simulates Day Ahead prices for future years (Scholten et al., 2016). This model incorporates developments in both the Dutch energy system the general European energy market into a unit commitment and economic dispatch model, resulting in so-called system marginal costs of production. These are the marginal costs of production for the total system, given a certain demand for power. With these system marginal costs of production, an analysis can be made of which production elements will produce at this marginal costs level, and which will be switched off for a certain period. The optimal combination of which generators are switched on, and how much power they should produce is then found using an iterative optimisation process. Finally, from these combinations, the power prices are derived.

The PowerFlex model has been thoroughly validated and back-tested to ensure its projections of future prices are accurate. Back-testing the model for 2013 and 2014 showed that overall, the simulated price data conformed to historical price data. Table 5-7 shows a statistical comparison of historical prices for 2013 and 2014 and the prices simulated using PowerFlex.

One big limitation of the model for scenarios in the future is that the simulated prices sometimes include extreme negative prices (<€-200 per MWh for 2030), which is caused by the PowerFlex model not being able to find a solution during hours of high electricity supply and low demand. Although it is expected that negative prices will occur more often in the future, prices this negative are not very likely to be witnessed in power markets. At such a

[3]The operating profit is the difference in the costs for charging and the benefits from discharging.

negative price level, it will become very lucrative for all kinds of market players to develop solutions for using electricity during these moments, which will help prices rise to a more normal level again. Because of that, for this research all projected 2030 negative power prices below €-10 per MWh have been set to the value of €-10 per MWh, which was the average electricity price during all negatively-priced hours in 2020. The threshold of €-10 per MWh was chosen to account for some must-run generators that will continue production at mildly negative prices. Data for the average negative electricity price in 2020 was obtained from the ENTSO-E transparency platform. (ENTSO-E, 2021).

Overall, the model has been validated positively, and continued use by CE Delft has shown the model to be sufficiently accurate for predicting EPEX prices. Therefore, for this thesis, prices simulated using the production and demand as assumed in the Climate Agreement for 2030 will be used, except for negative prices below€-10, which will be set at €-10 per MWh.

Table 5-7: Statistical comparison of PowerFlex simulated prices for 2013 and 2014 and historical EPEX DAM prices for 2013 and 2014. Adapted from (Scholten et al., 2016).

	PowerFlex 2013	EPEX DAM 2013	PowerFlex 2014	EPEX DAM 2014
Avg. price (€)/MWh & std. dev.	51.48 ± 13.46	51.49 ± 13.36	42.05 ± 10.99	41.18 ± 10.72
Min. price (€)/MWh	7.49	0.00	11.52	0.12
Max. price (€)/MWh	125.78	130.27	96.76	96.69

Curtailment costs

As explained in section 4-2, the battery + curtailment system uses the expected curtailment costs for the DSO to optimally dispatch the battery + curtailment system, whithin the station's capacity limits. The curtailment costs for the DSO consists of the EPEX price at the moment of curtailment, plus an additional fixed amount per MWh for the loss of subsidies and Guarantees of Origin.

Because curtailment by DSOs is relatively new and has occurred a lot yet, it is challenging to estimate the additional fixed amount per MWh included in the curtailment cost. The best sources were the DSOs themselves, but when asked, estimates from Stedin, Enexis and Liander varied over a large range (€0 - €600 per MWh). Experts from Stedin quoted a price of €125 + EPEX price per MWh, which was verified by multiple employees. Therefore, for the model and case study, curtailment costs of €125 + EPEX per MWh will be used. Because of the large uncertainty, a sensitivity analysis using different curtailment cost levels has been included in appendix C-0-1.

5-5 Selection of battery technology

The last important decision to make for using the developed models on the case study, is which type of battery to use. For selecting the battery type to use in the model and costs calculations, three criteria were used:

1. The technology has been proven to function in large-scale ($\geq$ 10 MW/10 MWh) stationary operations connected to the grid.
2. The technology is currently still being improved by significant research efforts.
3. The technology is predicted show a significant reduction in costs by 2030.

Lithium Ion Nickel Manganese Cobalt

The lithium ion NMC battery is currently the most common Li-Ion composition for both EVs and utility-scale storage systems. Examples of this system include Moss landing storage system, which was the largest battery storage system in the world in January 2021 at 300 MW/1200 MWh (Colthorpe, 2021).

A report by the IEA and the European Patent office states that NMC cathodes have seen the most highly innovative breakthroughs over the past 20 years (IEA, 2020a). The report analysed over 65,000 battery-related patent filings from 2000-2018 to come to this conclusion. The report also states that prices for stationary Li-Ion NMC batteries have come down by two-thirds since 2000 and are expected to keep decreasing. A study that applied a learning curve model to the costs of Li-Ion NMC battery storage systems found that by 2024, costs should fall below $ 100/kWh, which is similar to industry expectations (Penisa et al., 2020). One drawback to the increasing popularity of the NMC composition is that cobalt is a rare element, but a crucial material for this battery. Scarcity might cause prices to rise in the future. Moreover, cobalt is often mined in dubious circumstances.

Lithium Iron Phosphate

Another type of Li-Ion battery that has been gaining ground over the past years is the Lithium Iron Phosphate (LFP) composition. Recently, a 200 MW LFP battery system came online in Texas (Sylvia, 2020). Research into LFP batteries is thriving: the IEA patent report indicated that LFP innovations might surpass NMC innovations in the coming years. Wood Mackenzie, an energy research firm, expects LFP battery systems to overtake NMC battery systems for stationary applications by 2030 (Gupta & Thakore, 2020). Price expectations follow that of the general Lithium Ion systems: Bloomberg New Energy Finance expects average prices to reduce to $100/kWh by 2023, a reduction of -91% compared to 2010 price levels (Henze, 2020).

Sodium-Sulphur

Compared to Li-Ion batteries, Sodium-sulphur (NaS) batteries have an advantage when their goal is to deliver energy over a longer period of time, mostly in stationary applications.

In 2015, a 38.5 MW/250 MWh NaS battery came into operation in Italy (Andriollo et al., 2016). The goal of this battery system was to integrate more renewables while also mitigating congestion and defer network investments. The battery system has since proven that it can indeed solve congestion issues and act as a primary and secondary reserve. Originally, NaS batteries could only operate at high temperatures (300 °C), but recent research efforts have led to the creation of room-temperature batteries (Krishan & Suhag, 2019). However, because of the original focus on stationary applications, research has not been boosted much by EV battery developments, as has been the case for Li-Ion batteries. However, reductions in the costs of NaS storage systems are expected: IRENA predicts a 56% reduction in total installed costs by 2030, compared to 2016 costs. Costs could fall from around 500 $/kWh to about 225 $/kWh by 2030 (IRENA, 2017b).

Vanadium Redox Flow

The big advantage of flow batteries is that their storage capacity is only limited by the size of their tank. Because of that feature, a few large-scale Vanadium Redox Flow (VRF) projects have been realised over the past years. In 2016, a 15 MW/60 MWh VRF battery was realised in Japan. The goal of this battery was to enable the integration of more renewables by providing short- and long-term frequency support. Tests during operation have shown the system capable of doing so (Yano et al., 2017). Research into VRF batteries is on the rise: because flow batteries are easier to scale to large energy capacities, they are getting more attention as possible grid-connected stationary systems to relieve congested power grids. The European Patent Office has seen a steady increase in the number of patents filed linked to VRF technologies in recent years: yearly patents increased from less than 10 in 2009 to 82 in 2018 (IEA, 2020a). Currently, VRF battery systems are still relatively expensive, coming in at around 315 $/kWh. However, IRENA expects that an increase in VRF battery efficiency will lead to a costs reduction of approximately 66% by 2030, indicating prices might fall to 118 $/kWh.

Technology selection

All four battery technologies discussed in this section have been proven in agreement with the proposed criteria. For the remainder of this thesis, the battery system will be modelled using LFP batteries. The reasoning behind this is three-fold: first of all, material (cobalt) scarcity issues in the future might cause NMC battery prices to increase or decrease less than expected. Second of all, Tesla, one of the current biggest large-scale battery manufacturers, recently announced a complete shift towards LFP batteries (Hanley, 2021). Third and finally, two employees from large Dutch utility companies that are developing battery systems as part of their asset base confirmed that they expect LFP batteries to be the dominant type in the Netherlands by 2030[4]. The battery parameters used for the dispatch models were taken from IRENA's costs-of-service tool, which includes projected battery parameters for LFP systems in 2030 (IRENA, 2017a). The parameters have been included in table A-1 in appendix A-5 for reference.

[4]One of them indicated that they will start working on VRF demonstration projects as well, but they expect these projects will remain more expensive than Li-Ion by 2030.

5-6 Summary of scenarios for station Waalsprong

In this chapter multiple elements of the case study have been described. This section presents an overview of the scenarios that will be modelled and studied. The following elements will be varied throughout the scenarios:

- The type of additional renewable generator.
- Battery model: either the model for the large battery solving all congestion is used or the battery + curtailment system.
- Battery and curtailment connection location, which only varies for the battery + curtailment system.
- Battery power (MW) and capacity (MWh): the battery capacity will be varied between 2-50 MWh, and the battery power will depend on the capacity. For capacities lower than 10 MWh, the battery power will be equal to the battery capacity. For capacities equal to or higher than 10 MWh, the battery power will be set at 10 MW[5]. For the large battery, the power will be set at 10 MW, and the modelling will conclude in the necessary battery size for solving all congestion.

Table 5-8 gives an overview of the defined scenarios and their associated names. In figures 3-3a and 3-3b, the difference between battery and curtailment placement at the substation and at the generator is highlighted. The system locations in this figure correspond to the scenarios 'Wind-Station' and 'Wind-Generator' from table 5-8. Graphic representations of all other system locations have been included in appendix A-3.

Table 5-8: All defined scenarios to be analysed in the next chapter. Gen. indicates generator, Bat. indicates battery, Curt. indicates curtailment and Loc. indicates location.

Scenario name	Additional Gen.	Bat. System	Bat. Loc.	Bat. Power	Bat. Capacity
Wind-Station	Wind 9 MW	Bat. + Curt.	Station	$\leq$ 10 MW	2-50 MWh
Wind-Generator			Generator		
Wind-Large		Large Bat.	Station	10 MW	To resolve congestion
Solar-70%-Generator	Solar 12.85 MWp connected at 70% (9 MW)	Bat. + Curt.	Station	$\leq$ 10 MW	2-50 MWh
Solar-70%-Station			Generator		
Solar-70%-Large		Large Bat.	Station	10 MW	To resolve congestion
Solar-100%-Generator	Solar 12.85 MWp connected at 100 %	Bat. + Curt.	Station	$\leq$ 10 MW	2-50 MWh
Solar-100%-Station			Generator		
Solar-100%-Large		Large Bat.	Station	10 MW	To resolve congestion
Wind/Solar-Station	Wind/Solar 4.5 MW/4.5MWp	Bat. + Curt.	Station	$\leq$ 10 MW	2-50 MWh
Wind/Solar-Generator			Generator		
Wind/Solar-Large		Large Bat.	Station	10 MW	To resolve congestion

[5]As the excess load on station Waalsprong is never more than 10 MVA, 10 MW of battery power will always be sufficient.

5-7 Battery model results for the case study of station Waalsprong

This section will present the results obtained by modelling all scenarios in table 5-8 for station Waalsprong. First, the results of the large battery model will be discussed. Second, the modelling results of the battery + curtailment models will be presented. Additionally, a section on the validation of the MATLAB models has been included in appendix A-4.

5-7-1 Large battery model results

The resulting battery sizes for resolving all hours of congestion for every considered additional generation scenario at station Waalsprong are included in the table 5-9. The battery in this model has a power of 10 MW, which should be enough to reduce all excess loads from table 5-6 to the station limits, as the peak load never exceeds the station limits by more than 10 MW[6].

From table 5-9 it is clear that for resolving all congestion with a single battery system, quite large systems will be needed. Integrating a 9-12.85 MW generator using a battery system with an energy capacity of 3-6 times the additional generator power does not seem like an efficient use of battery capacity. Furthermore, the battery is only used for 7-12 complete cycles for the simulated year.

The difference between the additional generations scenarios considered is significant. For the wind/solar scenario, less than half the battery capacity of the wind scenario can be used to solve all congestion. This difference is caused by two things. First of all, the wind scenario causes the largest overall excess load volume, as described in section 5-3. Secondly, in the wind/solar scenario, wind and solar generation cause generation peaks at different moments, reducing the total congestion caused by this scenario. This results in a smaller battery being sufficient for all moments of excess loads.

Table 5-9: Model outcomes for solving all congestion hours at station Waalsprong. The battery power was set at 10 MW.

Additional generation scenario	Battery size (MWh)	Annual cycles
Wind 9 MW	54	12
Solar 9 MW (12.85 MWp at 70%)	38	11
Solar 12.85 MWp	47	12
Wind/Solar 4.5/4.5 MW	26	7

[6]The peak load is -19.47 MVA for the solar 100% scenario, and the station limit is -10.5 MVA.

5-7-2 Battery + Curtailment system model results

This section will examine the model results of the developed battery + curtailment system for both system locations. All battery + curtailment scenarios included in table 5-8 have been modelled for station Waalsprong, and the results of this exercise are included in the figures below. In appendix A-4, a section on the validation of both models has been included. The models were used for battery sizes up to 50 MWh, but the plotting range was set to a maximum of 30 MWh for most figures because there were limited changes in the results for batteries larger than 30 MWh. In the legend of the figures, the plotted lines are labelled by additional generator, and the connection location of the battery + curtailment system[7]. It should be noted that only the specific reduction in curtailment costs for the DSO is included in these figures, and other costs (e.g. the capital costs of the battery system) have not been included. These costs will be analysed in chapter 6.

The model's primary goals were to combine battery use and curtailment optimally, minimise curtailment costs over the year, and prevent the substations capacity limits from being exceeded. These goals were achieved: the maximum absolute load on station Waalsprong during the simulated year was 10.5 MVA (equal to the station limit), and the reduction in curtailment costs is significant, as demonstrated by figures 5-17 and 5-16. Figure 5-16 shows how the absolute annual curtailment costs are influenced by increasing the battery capacity: adding a relatively small (5-10 MW) battery system reduces curtailment costs substantially. Figure 5-17 shows the relative reduction in annual curtailment costs for different battery sizes. From both figures, it is clear that the additional reduction in curtailment costs is limited for battery sizes larger than 10-15 MW at station Waalsprong.

The effect of changing the location of the battery and curtailment system seems very limited: The largest location-caused difference in curtailment costs reduction is visible for the 100%-connected solar case at station Waalsprong: there, a battery at the generator has a slightly larger impact on reducing curtailment costs. In the plot of the absolute values, this difference is barely visible because the difference between the curtailment costs is minimal: the largest spread is €43 at a battery size of 5 MWh. In chapter 8, explanations for the similarity in curtailment for the two connection locations will be discussed. The effect of varying the renewable generator is more visible: the most significant relative reduction in curtailment costs is visible for the combined wind/solar generator, and the smallest for the 100%-solar generator, when regarding figure 5-17. It should however be noted that the absolute curtailment costs for the combined wind/solar generator were significantly lower to start with.

The second feature of the system to examine is the volume of electricity curtailed in all scenarios. Figure 5-18 plots the absolute volume of electricity curtailed for every scenario, and figure 5-19 plots the change in curtailment volume for every system location. Figure A-17 in appendix A-6 shows the energy curtailed relative to the energy generated by the additional renewable source for all scenarios. There are two interesting elements to note from these figures. Firstly, the volume of curtailed electricity is relatively low for all scenarios at station Waalsprong: this is because the station limits were only exceeded for 105 (wind/solar case) - 412 (wind case) hours during the simulated year, as described in table 5-6. Secondly, again there are almost no discernible differences between the two connection locations for the battery and curtailment system. This is not unexpected: by connecting the additional

[7] The combination of the additional generator and the connection location was defined as the system location.

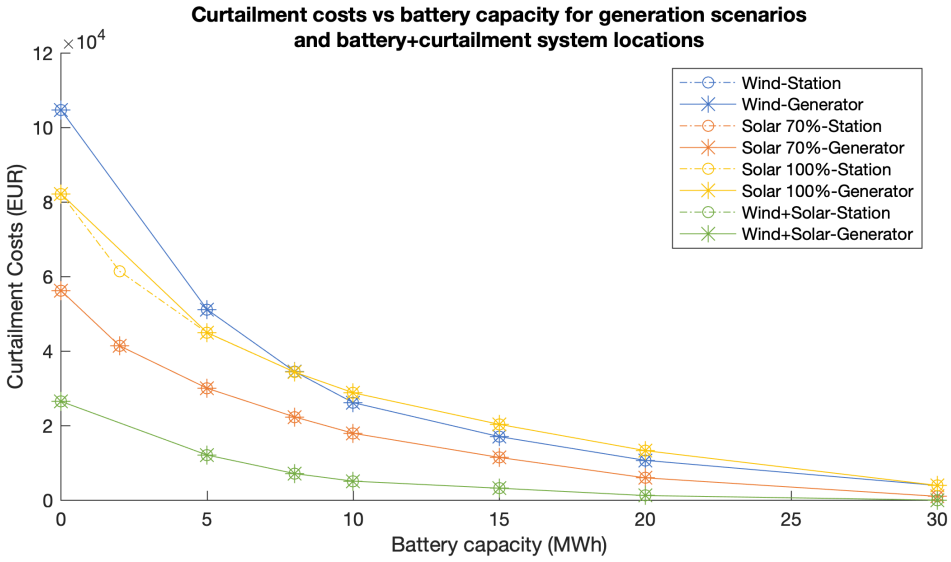


Figure 5-16: Plot of the absolute curtailment costs for all 2030 scenarios at station Waalsprong, at varying battery capacities.

generator to the substation, excess load is created, which can be negated by curtailing that load. The only visible difference is again for the solar generator connected at 100%: the curtailment volume is slightly higher when the battery + curtailment system is located at the station. The two lines for the solar generator connected at 70% run exactly behind the solar-100% generator plot, and are therefore not visible. Overall, the battery + curtailment system results are positive: a 10MW/10MWh battery can reduce curtailment volume by over 60% for all scenarios and system locations at station Waalsprong. This is visible in figure 5-19.

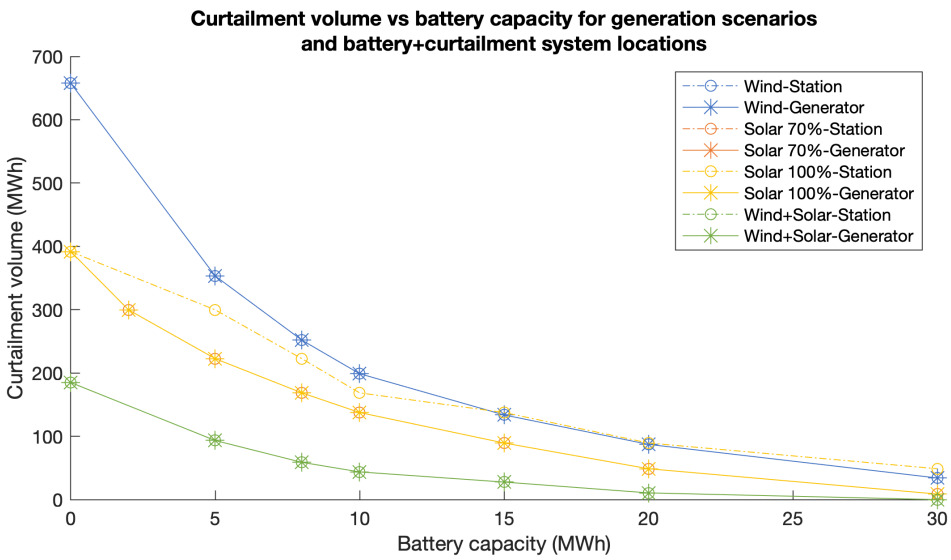


Figure 5-18: Plot of the volume of energy curtailed for the different generator scenarios and locations of the battery + curtailment system at station Waalsprong.

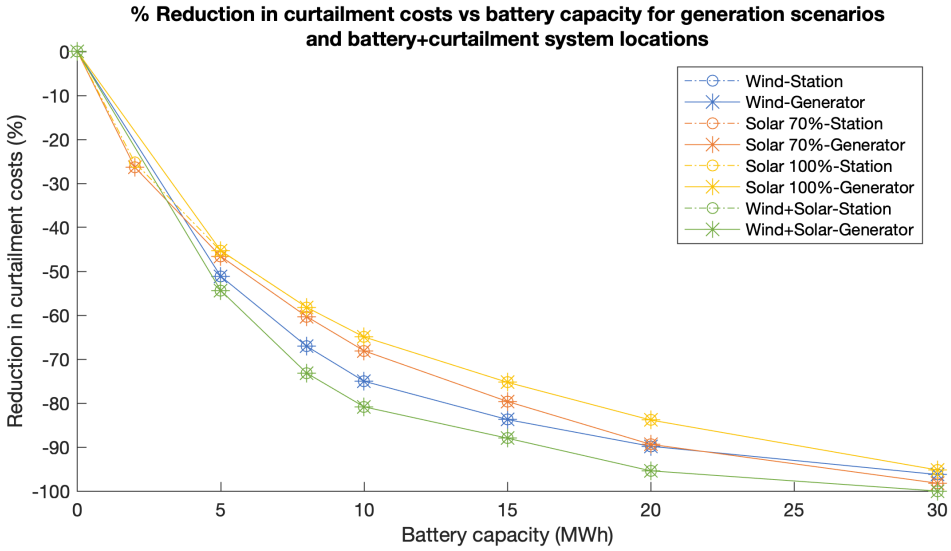


Figure 5-17: Plot of the relative reduction in curtailment costs for all 2030 scenarios at station Waalsprong, at varying battery capacities.

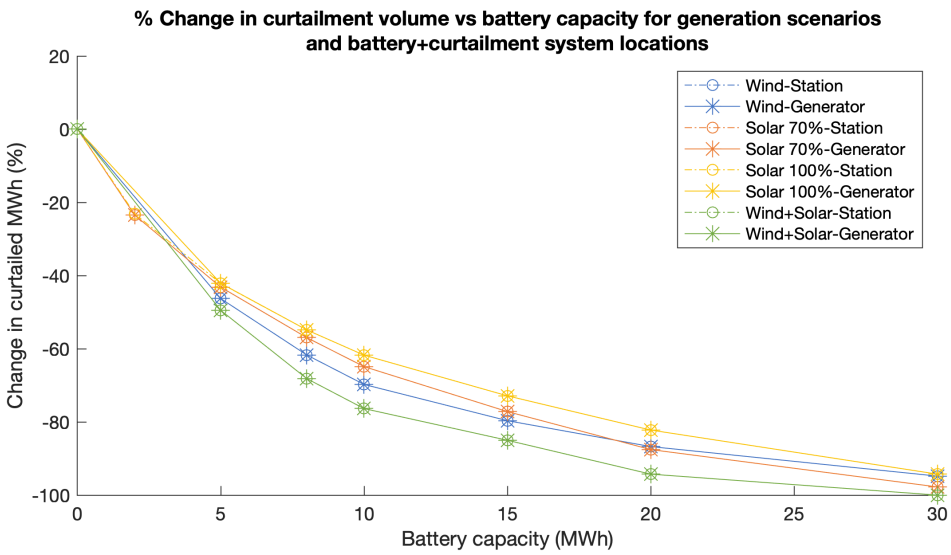


Figure 5-19: Plot of the change in volume of energy curtailed for the different generator scenarios and locations of the battery + curtailment system at station Waalsprong.

In figure A-18 in appendix A-6, the total number of complete battery cycles occurring for every scenario and battery capacity over the year is plotted. The number of battery cycles is calculated by dividing the total energy flowing into the battery by the battery's total capacity. Generally speaking, the number of battery cycles during the year is relatively low: between 30-197 annual cycles for a 10MW/10 MWh battery in all scenarios at station Waalsprong. During a full year, a 10 MW/10 MWh battery could theoretically go through 4392 cycles if the loads were sufficient[8]. However, a low number of cycles is positive for

[8]If it used half the hours in the year for full-power charging, and the other half for full-power discharging.

preventing fast degradation of the battery. Again, for most generation scenarios, no large differences[9] between the two locations of the battery system are present. The only scenario with a discernible difference is the solar connected at 100%-scenario, which generates more annual cycles for battery placement at the station.

Because the battery often charges during high-generation moments and discharges during low-generation moments, it is likely that the battery buys power at relatively low prices and sells power at relatively high prices. That will cause it to generate an operating profit[10]. Figure 5-20 shows the battery operating profit during 2030 at station Waalsprong. The difference between the generation scenarios is striking: the solar generator connected at 100% with the battery + curtailment system located at the generator delivers a significantly higher operating profit than all other scenarios. For a 10MW/30 MWh battery with solar and curtailment connected at the 100% solar generator, the total battery operating profit realised for 2030 was approximately €30k. This effect can be explained by the fact that the 100%-connected solar scenario has a higher output (12.85 MW) than all other generation scenarios (9 MW).

Figure 5-20 is the only figure showing significant differences for the two connection locations. For all additional renewable generation scenarios, connecting the battery + curtailment system at the generator location leads to substantially higher operating profits. Both solar scenarios show the largest spread in operating profit for the different connection locations. All series follow almost a linear shape for a while, which is not unexpected for battery profits at increasing battery capacity. In chapter 8, likely explanations for the difference in operating profit for the generator and station locations will be discussed.

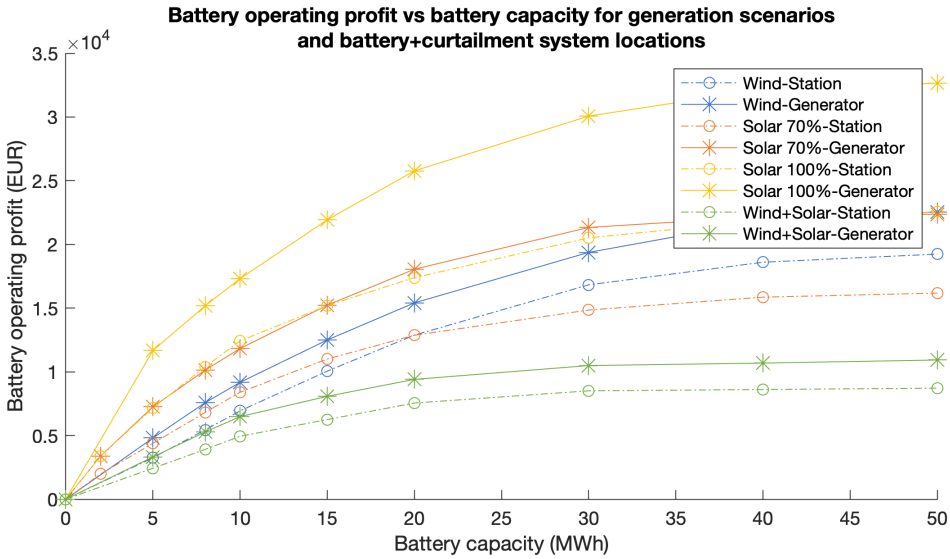


Figure 5-20: Plot of the battery's annual operational profit for the different generator scenarios and locations of the battery + curtailment system at station Waalsprong. The profit consists only spread in electricity prices between charging, other costs and benefits have not been included.

[9]Minor differences of about 1% of the values are present.

[10]The operating profit is defined as the difference between the charging costs and the discharging revenues. No other costs or benefits have been included.

Chapter 6

Case study of an MV substation: economic analysis

This chapter will analyse the economics of the developed battery systems by performing a cost-benefit analysis (CBA). This CBA will compare four different solutions for integrating additional renewable generation capacity into the already congested network at station Waalsprong. As can be seen on the left of figure 6-1, the base case consists of the congested (sub)station, where no extra generation capacity can be connected. The most straightforward possible course of action would be to refrain from adding new generation capacity. However, with the current Dutch power system and future decarbonisation goals, this is often not possible. The right side of figure 6-1 depicts the four options considered to integrate additional generation capacity into an already constrained network evaluated in this thesis. The options are the following:

1. **Curtailment by DSO**
   When the additional connected generation capacity leads to overloads, the first solution is to apply congestion management or to curtail the excess load on the station. The main costs associated with this option are the costs of congestion management or curtailment. These curtailment costs are a remuneration of the lost revenue for the generator, paid by the network operator. This lost revenue consists of the EPEX electricity price, subsidies over the generated electricity and the value of the Guarantee of Origin, which is assigned to renewable electricity. Under current Dutch regulations, curtailment is a temporary solution, as explained in section 2-1.

2. **Grid upgrade**
   The second solution to connect additional capacity to the station is to upgrade and expand the network and substation capacity. The main costs associated with this solution are the CAPEX of the new network components. To ensure a proper comparison between the situations, the grid upgrade considered here is only just large enough to fit

the consumer loads, generators and additional renewables connected[1].

3. **Large battery solving all congestion**
   The third solution to connect additional generation capacity to the station is by integrating a battery system that is large enough to resolve all moments of congestion. The main costs associated with this are the CAPEX of the battery system. An additional benefit from this solution is the battery operating profit, the battery's revenue from charging and discharging.

4. **Battery + curtailment system**
   The fourth solution to connect additional generation capacity to the station is by integrating a combined battery and curtailment system. Together, these components can resolve all moments of congestion and collaborate optimally to reduce the curtailment costs. The costs associated with this system are the CAPEX and OPEX of the battery system, the (reduced) curtailment costs and the conversion costs stemming from battery losses. The main benefit is the battery operating profit. The battery plus curtailment system can either be connected directly to the substation, as depicted in figure 6-1 part 4a or it can be connected to the generator, as shown in figure 6-1 part 4b.

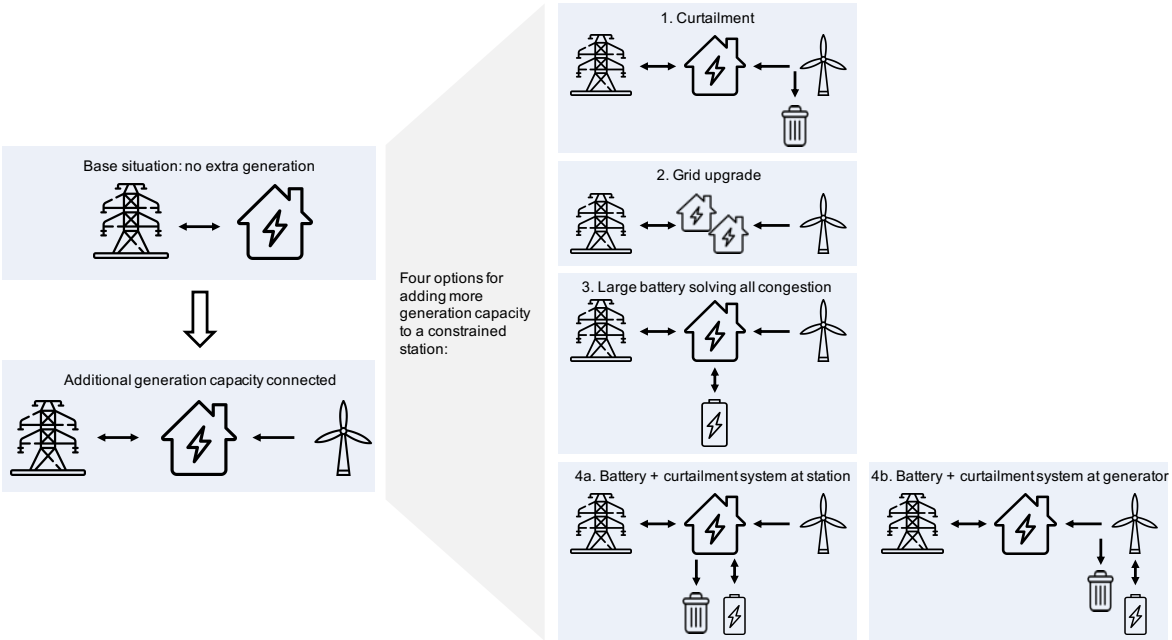


Figure 6-1: Diagram of the different scenarios available for integrating extra renewables in an already constrained grid.

[1]In reality, grid upgrades are not made on a customised per MW-basis but in larger, discrete steps such as adding an extra transformer to the system.

CBA parameters

To perform the cost-benefit analysis, information was gathered from a range of literature and from the models used in this thesis. This section describes how the numbers in tables 6-1 and 6-2 were generated and discusses other parameters used in the analysis.

Discount rate
To account for the time value of money, a discount rate is used on the annual costs and benefits. The used discount rate is 2.5%, a standard rate for network operators set by the Authority for Consumers & Markets.

Timeline
To ensure the benefits of grid upgrades are incorporated fully, a timeline of 50 years has been chosen. Upgrading the grid will take 5 years on average, and these upgrades can operate for 45 years. However, the battery has a maximum calendar lifetime of 18 years, and thus it will have to be replaced during the considered period (NREL, 2019).

Battery and inverter CAPEX and OPEX
The capital expense of the battery installation and inverter were estimated using IRENA's Cost-of-Service tool (IRENA, 2017a). This tool estimates battery system costs for multiple years into the future, and for different lithium-ion technologies, including LFP. The tool has also analysed numerous sources to deduct the operating expenses for utility-scale batteries and inverters; these were concluded to be 1.5% of the total CAPEX investment. Finally, all costs were converted from USD to EUR using a 1:0.82 factor, the exchange rate on the first of June 2021.

Battery system lifetime
Using the same IRENA tool, the battery system lifetime for LFP in 2030 has been estimated. The expected lifetime is 18 years or 4774 cycles. This lifetime has been verified by GIGA storage, which is also planning on using LFP batteries in the near future. The degradation of the battery has been included in the CBA analysis in two ways. First, costs for degradation are included as an annual reduction in battery operating profit that is equal to the capacity fade per cycle times the annual number of battery cycles, as described in section 4-2-3. Second, an assessment is made of the total number of cycles gone through: if this number exceeds the cycling lifetime of the battery system, the system will be replaced sooner than after 18 years. If the cycling lifetime is not reached, the battery will be replaced in 2048 and 2066. The final battery will not have reached its calendar lifetime at the end of the cost-benefit analysis, and therefore a residual value will be included. This value is equal to the number of useful years left divided by the calendar lifetime, times the capital expense of the battery system.

Learning factor
Battery costs tend to reduce drastically over longer periods, so a learning factor is used to account for this in the costs for the battery system replacements. The National Renewable Energy Laboratory (NREL) of the United States has done an extensive literature review of cost trajectories for utility-scale battery storage up to 2050 (NREL, 2019). Assuming the cycling lifetime is not reached before the calendar lifetime, the battery system will be replaced

in 2048 and 2066. For the second replacement of the battery (2066), no cost trajectories have been determined yet. Therefore, this thesis will assume the same NREL learning factor for both periods, which is equal to a 24% reduction in system costs over a period of 18 years.

Battery operating profit
The aim of the battery is not to charge optimally for profit maximisation. Still, as low prices often occur during moments of peak generation, the battery system will tend to charge during low prices and discharge during high prices. Both the excel model and the MATLAB model calculate the annual operating profit from using the battery, and this benefit is included in the CBA. To account for battery degradation, the annual operating profit is reduced linearly with the number of battery cycles completed relative to the total cycling lifetime of the battery. However, because the annual number of cycles is relatively low (<200 annual cycles) for all scenarios, the correction in the operating profit from battery degradation is minimal[2]. The annual battery operating profit is different for every scenario, so it has not been included in tables 6-1 and 6-2.

Curtailment costs
The costs of curtailing excess generation were discussed with three different DSOs. Answers varied, so in section C-0-1, a sensitivity analysis to the cost level of curtailment has been included. For this cost-benefit analysis, the costs quoted by Stedin were used[3], which amount to €125 per MWh + the EPEX price during curtailment. The €125 per MWh are compensation for the lost subsidies and guarantee of origin rewards. The annual curtailment costs differ per scenario, so they have not been included in tables 6-1 and 6-2. In section 5-7-2, plots of the annual curtailment costs for the different battery models have been included.

Land use and land costs
All solutions except curtailment will take up space in the network area. Recent estimates of how much space batteries and MV stations take up have been included in the tables 6-1 and 6-2. To deduct the value of this land use, the average price of vacant lots sold in 2020 in the Netherlands has been used (Kadaster, 2021).

Connection cable
To connect the battery or grid upgrade to the network, extra MV network cables will have to be put into place. Network operators have estimated that MV cables cost €250/m on average to buy and install. For all cases, an extra 500 metres of cable were assumed.

Costs of HV/MV station and MV grid
In 2017, CE Delft performed the 'Net voor de Toekomst' study, which included an estimation of the value of all (large) grid components and the grid itself. Key figures from that study have been used in this thesis for evaluating the costs of network upgrades. It was assumed that construction takes 5 years for all network upgrades, and the elements have a lifetime of 45 years.

[2]Less than 1% in the wind-generation scenarios, which have the highest number of cycles.
[3]This price level was confirmed by the product manager of flexibility at Stedin during an interview and follow-up emails.

Table 6-1: Parameters used for calculating the costs of the battery system. All sources are included in the table.

Parameter	Value	Comments	Source
Discount factor	2.5%	Discount factor used by DSOs	ACM
Battery energy costs (CAPEX)	183.8 EUR/kWh	LFP prices for 2030	(IRENA, 2017a)
Inverter costs (CAPEX)	41.492 €/kW	Large inverter prices for 2030	(IRENA, 2017a)
Land use battery	52.1 m^2/MWh	Average land use, utility-scale batteries in NL	(Generation.Energy, 2021)
Land costs NL	491.93 €/m^2	2020 average value of sold lots	(Kadaster, 2021)
Connection cable costs	250 €/m	Assume 500 m of MS cable for all cases	(Netbeheer Nederland, 2019)
Battery OPEX	1.5% of bat. CAPEX	per year	(IRENA, 2017a)
Inverter OPEX	1.5% of inv. CAPEX	per year	(IRENA, 2017a)
Battery system lifetime	18 years or 4774 cycles		(IRENA, 2017a)
Learning factor battery + inverter	-24%	Cost reduction 2030-2048 and 2048-2056, for replacing the battery after lifetime	(NREL, 2019)

Table 6-2: Parameters used for calculating the costs of the grid upgrade. All sources are included in the table.

Parameter	Value	Comments	Source
Discount factor	2.5%	Discount factor used by DSOs	ACM
Costs of HV/MV station	250 €/kW	Average costs of station, Construction time 5 years, lifetime 45 years	(CE Delft, 2017)
Costs of MS grid	705 €/kW	Average costs of MV grid in NL, Construction time 5 years, lifetime 45 years	(CE Delft, 2017)
Land use MV station	100 m^2/MVA	Average land use of MS stations in NL	(Netbeheer Nederland, 2019)
Land costs NL	491.93 €/m^2	2020 average value of sold lots	(Kadaster, 2021)

6-1 Cost-Benefit Analysis results

The cost-benefit analysis was performed by evaluating the net present value of all in- and outgoing cash flows for every scenario at station Waalsprong, depicted in figure 6-1. The battery size was set at 10 MW/10 MWh because previous analyses in section 5-7-2 indicated that batteries larger than this resulted in no significant extra benefits at station Waalsprong[4]. All analyses were assumed to start at the beginning of 2030 and end in 2079 to include the entire lifetime of grid upgrades. To determine the influence of system location on the value the battery system has for the regional network operator, a comparison of the CBA outcomes will be discussed in the final section of this chapter, section 6-2.

6-1-1 Curtailment

For the cost-benefit analysis of the curtailment scenarios, generation was curtailed in such a way that the Waalsprong station limits were never exceeded during the test year. Figures B-1, B-2, B-3 and B-4 show the cash flow and NPV results of the cost-benefit analysis for all curtailment scenarios at station Waalsprong, and have been included in appendix B. The NPV results have also been included in table 6-3. Overall, at Waalsprong the total curtailment costs over the 50 years are the highest for the additional wind generation case, followed by the 100%-connected 12.85 MWp solar generation case. It is striking that the curtailment costs from the combined wind/solar generation case are significantly lower than for all other cases. This effect is caused by the shift of production peaks from combining two sources of generation.

[4]For other stations, the optimal battery size could of course be different.

Table 6-3: Overview of the cost-benefit analysis results for the four curtailment scenarios at station Waalsprong. The NPV numbers included in this table are the net present value of the total costs over the 50 years.

Additional generation	Annual curtailment (MWh)	Total NPV of curt. costs (M€)
Wind 9 MW	658	-3.04
Solar 12.85 MWp connected at 70% (9 MW)	392	-1.63
Solar 12.85 MWp connected at 100%	566	-2.39
Wind/Solar 4.5 MW/4.5 MWp	185	-0.77

6-1-2 Grid upgrade

For the grid upgrade, it was assumed nominal depreciation expenses for the grid upgrade CAPEX were equal for every year in the considered 50 year period. All costs for grid upgrades were made on the basis of providing exactly enough additional capacity to integrate the highest generation peak in each scenario. Figures B-5, B-6, B-7, and B-8 depict the final cash flow and NPV results of the cost-benefit analysis for grid upgrades at station Waalsprong, and have been included in appendix B. The total net present value of the grid upgrade costs for every scenario has been included in table 6-4. The results are as expected: the scenarios that cause the largest peak loads on the station also face the highest grid upgrade costs.

Table 6-4: Overview of the CBA results for the four grid upgrade scenarios at station Waalsprong. The NPV numbers included in this table are the net present value of the total costs over the 50 years.

Additional generation	Peak load on station (MVA)	Total NPV of grid upgrade costs (M€)
Wind 9 MW	-17.40	-4.03
Solar 12.85 MWp curtailed to 9 MW	-18.62	-4.74
Solar 12.85 MWp	-19.47	-5.24
Wind/Solar 4.5MW/4.5MWp	-16.96	-3.78

6-1-3 Large battery solving all congestion

This CBA was performed at a battery size resulting in no excess loads on station Waalsprong during the simulated year. That battery size has been calculated in section 4-1. The battery systems never reach their cycling lifetimes, so all systems are replaced after 18 years as described in the CBA parameters. In table 6-5 the final net present values of the total system cost and benefits over the 50 year period are included for station Waalsprong. The resulting cash flows have been plotted in figures B-9, B-10, B-11 and B-12 in appendix B.

When comparing the CBA results for the four scenarios, two things stand out. First of all, the large battery sizes cause very negative (and thus expensive) NPVs for all scenarios. Secondly, the annual battery profit is substantially higher for the wind scenario than for all others. This is likely caused by the fact that the wind generation scenario leads to the largest excess loads, resulting in more use of the battery system. The results from this analysis diverge widely

from the CBA results of other solutions: because of the large battery necessary for integrating all generation, the total NPV of this system is also very negative. The large battery is not a cost-effective solution for integrating additional renewable generation at station Waalsprong.

Table 6-5: Net present value of solving all congestion with a large battery in the four scenarios at station Waalsprong. All battery systems have a fixed power of 10 MW. The annual profit is the value for the first year of battery operation, and is reduced over the following years with battery degradation.

Additional generation	Battery size (MWh)	Annual battery profit (k€)	Total NPV (M€)
Wind 9 MW	54	24.1	-22.7
Solar 12.85 MWp curtailed to 9 MW	38	13.7	-16.1
Solar 12.85 MWp	47	16.7	-19.9
Wind/Solar 4.5MW/4.5MWp	26	8.60	-11.1

6-1-4 Battery + curtailment system located at the substation

This cost-benefit analysis was performed using the output values from the developed MATLAB model that ensures the capacity limits of the station Waalsprong are never exceeded, while minimising the total curtailment costs and battery degradation costs. For this case, the 10 MW/10 MWh battery was connected directly to the substation. The exact model rules and outcomes have been included in chapter 4 and section 5-7.

Figures B-13, B-14, B-15 and B-16 show the resulting cash flows for the battery + curtailment system connected at station Waalsprong, with different additional renewable input profiles. All figures have been included in appendix B. In table 6-6, an overview of the results for each scenario has been included. This table demonstrates that the NPV of the total system varies per generation scenario, but not as much as in the previous cost-benefit analyses. All systems considered for station Waalsprong have a negative NPV around minus €4-5 million. As in the previous analyses, the wind/solar combined generation addition results in the least costs. The solar scenarios result in the highest annual battery operating profits.

Table 6-6: Overview of the CBA results for the four additional renewable scenarios, with a battery and curtailment system located at substation Waalsprong. The NPV numbers are the net present value of all costs and benefits over the 50 years. All other number are annual, the battery operating profit is the value for the first year of operation, after which the profit decreases with the battery degradation. Curt. indicates curtailment, Bat. battery, An. annual.

Additional generation	An. curt. (MWh)	An. curt. costs (k€)	An. bat. profit (k€)	Total NPV (M€)
Wind 9 MW	199	26.2	6.93	-4.78
Solar 12.85 MWp curtailed to 9 MW	138	17.9	8.40	-4.49
Solar 12.85 MWp	217	28.8	12.4	-5.19
Wind/Solar 4.5MW/4.5MWp	44	5.08	4.95	-4.22

6-1-5 Battery + curtailment system located at the generator

This cost-benefit analysis was performed using the output values from the developed MATLAB model that ensures the capacity limits of station Waalsprong are never exceeded while minimising the total curtailment costs and battery degradation costs. For this case, the 10 MW/10 MWh battery was connected at the generator. The exact model rules and outcomes have been included in chapters 4 and 5-7.

Figures B-17, B-18, B-19 and B-20 show the resulting cash flows for the battery + curtailment system connected at the generator for different additional renewable input profiles integrated at station Waalsprong. All figures have been included in appendix B. In table 6-7, the final net present value of the systems' costs and benefits over 50 years is included and annual values for curtailment volume, curtailment costs, and battery operating profits. The total net present value is the highest (least negative) for the combined wind/solar generation scenario, which has significantly lower curtailment costs compared to all other solutions. This is due to the reduction in excess load caused by combining different generation sources. All total NPV values are between minus 4 and minus 5 million euros for the scenarios considered at station Waalsprong, and the differences between the CBA outcomes are not that large. Again, both solar scenarios result in the highest annual battery operating profit.

Table 6-7: Overview of the CBA results for the four additional renewable scenarios at station Waalsprong, with a battery and curtailment system located at the generator. The NPV numbers are the net present value of all costs and benefits over the 50 years. All other numbers are annual, the battery operating profit is the value for the first year of operation, after which the profit decreases with the battery degradation. Curt. indicates curtailment and Bat. battery.

Additional generation	An. curt. (MWh)	An. curt. costs (k€)	An. bat. profit (k€)	Total NPV (M€)
Wind 9 MW	199	26.2	9.17	-4.71
Solar 12.85 MWp curtailed to 9 MW	217	17.9	11.8	-4.39
Solar 12.85 MWp	217	28.8	17.3	-4.63
Wind/Solar 4.5MW/4.5MWp	44	5.08	6.48	-4.17

6-2 Comparison of the costs and benefits of the different solutions

In figure 6-2, an overview of the NPV of the total costs and benefits over the 50 year period has been included for all additional generation scenarios and four of the five congestion solutions from the previous analysis. The large battery solution has not been included because it performed substantially worse than all other solutions. All analyses were performed using the station Waalsprong case study. In table 6-8, the net present value of all five solutions for all considered generators has been included.

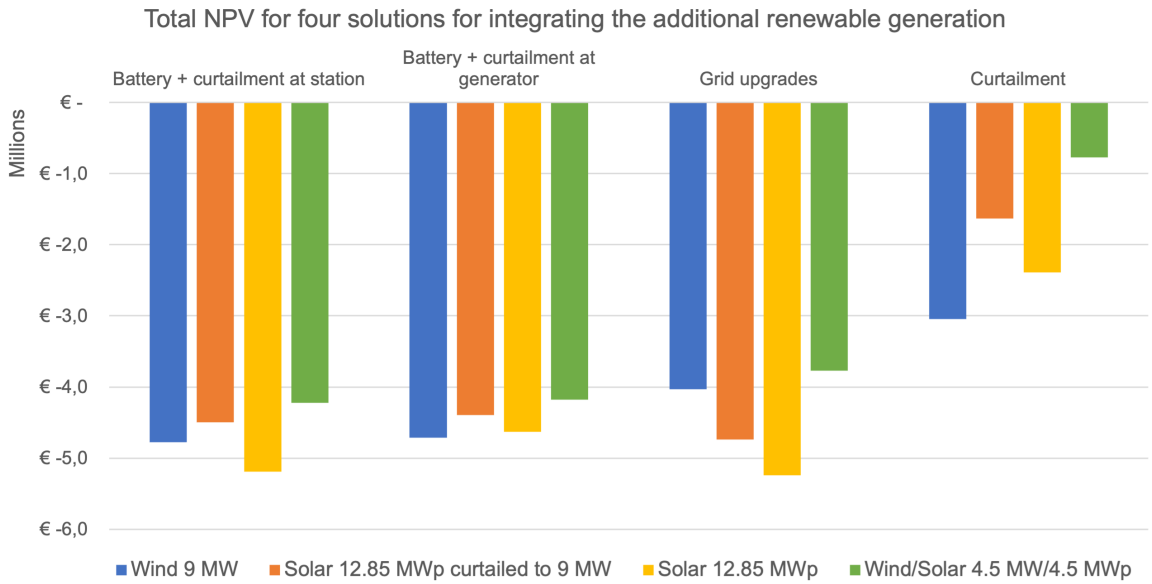


Figure 6-2: Diagram of the total NPV associated with different solutions for integrating the additional renewable generation capacity at station Waalsprong without congestion in 2030.

Figure 6-2 demonstrates several noteworthy results. First of all, the curtailment solution is significantly less expensive than all other solutions for integrating the additional renewable generation at station Waalsprong. However, when considering curtailment as a solution, there are two things to keep in mind: first, it is only allowed as a temporary solution under current regulations. Second, one should think critically if choosing the curtailment option for many cases is a desirable solution: it might result in lower integral costs for society as a whole, but it will also mean significantly less renewable electricity can be transported. With current climate goals and electrification trends, the Netherlands might need all the renewable power it can generate in the future. This will be discussed more extensively in section 7-6.

The second element to note is that grid upgrades are more expensive than the battery + curtailment systems for both solar generation cases at station Waalsprong. This effect can be explained by the daily shape of the solar profile: peak capacity is only reached during a small window of time, whereas wind turbines can retain their peak capacity for hours on end. Therefore, when sizing the grid upgrade for this peak, the grid is used more effectively for wind than for solar. For the combined wind/solar generation scenario, the grid is used even more efficiently, and this is reflected by the CBA outcomes: grid upgrades are the least-cost solution.

Table 6-8: Overview of the net present value of the five considered options for integrating the additional renewable generators in the first column at station Waalsprong. All NPV values are in million €, and over the entire 50 year period. Bat. indicates battery, and curt. curtailment.

Additional generation	Bat. + curt. at station (M€)	Bat. + curt. at generator (M€)	Large bat. (M€)	Grid upgrade (M€)	Curtailment (M€)
Wind 9 MW	-4.8	-4.7	-22.7	-4.0	-3.0
Solar 12.85 MWp curtailed to 9 MW	-4.5	-4.4	-16.1	-4.7	-1.6
Solar 12.85 MWp	-5.2	-4.6	-19.9	-5.2	-2.4
Wind/Solar 4.5 MW/4.5 MWp	-4.2	-4.2	-11.1	-3.8	-0.8

The final interesting aspect of this graph is the difference between locating the battery and curtailment system at the substation or at the generator. The graph shows little difference for the combined wind/solar scenario. For all other additional generators, there are minor differences in the CBA outcomes for the different connection locations. For both solar scenarios and the wind scenario, locating the battery + curtailment system at the generator is advantageous in terms of costs. This effect is most visible for the non-curtailed solar generator, which is likely due to its increased output. The differences are caused mainly by the higher operating profits achieved by the battery located at the generator.

Chapter 7

Batteries in the Dutch power system: current and future context

This chapter will analyse the current institutional context of utility-scale batteries in the Netherlands and look ahead to how this context will develop in the coming years. This chapter aims to answer the question: *"How does the institutional context impact the value of battery energy storage systems for the Dutch regional power system?"*. In relation to the main research question, this chapter will also investigate how that value depends on the system location.

First, the main stakeholders and their roles will be discussed. Second, current regulations and incentives present will be analysed, as well as their influence on battery system implementation. Third, an overview will be provided of the different possibilities for owning and operating a battery in the Netherlands and a qualitative assessment of the impact such operations can have on regional power grids. This will be followed by an overview of the largest barriers to the widespread adaptation of utility-scale batteries in the Netherlands, and recommendations to overcome them. Finally, this chapter will present a selection of dilemmas policymakers will face when considering the various roles for battery systems in the Netherlands. The information presented in this chapter was gathered from existing literature and from ten interviews with relevant parties. An overview of the conducted interviews has been included in appendix D.

7-1 Stakeholders

This section will provide an overview of the most relevant stakeholders for battery energy storage systems in the regional power system. It will give a high-level definition of the stakeholders and discuss the stakeholders' main tasks.

Transmission System Operator

The transmission system operator (TSO) is responsible for operating, maintaining and de-

veloping the transmission system to ensure reliable transportation of electricity in the most effective way. In the Netherlands, this means the TSO (TenneT) is responsible for the transport of electricity over the high-voltage grid at a voltage of 110 kV or higher. The TSO is also responsible for preserving the system balance. All parties connected to the network are balance responsible and need to specify how much power they will supply to and demand from the network each day. TenneT reconciliates these programs using imbalance pricing and ensures sufficient reserve- and emergency power is available to stabilise the network during imbalance events.

Distribution System Operators

The distribution system operators (DSOs) are responsible for operating, maintaining and developing the distribution system to ensure the reliable transportation of electricity in the most effective way. In the Netherlands, this means that the 7 different DSOs[1] are responsible for the transport of electricity at all voltage levels below 110 kV, up until the connection point for consumers or generators.

Regulator

Since the mid-1990s, the European Union has focused on liberalising and restructuring the internal electricity markets. In the Netherlands, ownership unbundling ensued: all network operations were separated from commercial activities, to separate natural monopoly activities from free-market activities (Tanrisever et al., 2015). The network activities were placed with the TSO and DSOs, and to ensure their optimal functioning, they are subject to heavy regulation. In the Netherlands, the Authority Consumer & Market (ACM) regulates the electricity sector. The Dutch Government develops the legislation on which the regulation is based and appoints the regulator.

Generators

Generators are companies that generate electricity, which they then feed into the grid at their connection point and sell to electricity suppliers, traders or consumers. Generators can sell their generated electricity in two ways: on the electricity markets or through Power-Purchasing-Agreements (PPAs), which are longer-term contracts for delivering electricity at a set price. The latter is more common in the Netherlands at the moment. On top of the electricity market price or PPA price, renewable generators often receive subsidies and revenues from their Guarantees of Origin.

Electricity suppliers

Electricity suppliers are parties that supply generated electricity from the grid to a consumer. Sometimes, electricity suppliers are generators too, but they can also buy electricity from stand-alone generators or on electricity markets.

[1] Coteq, Enduris, Enexis, Liander, Rendo, Stedin, Westland Infra

Electricity traders

To facilitate the free trade of electricity, multiple market platforms have been developed, both for trading short-term (EPEX) and long-term (ENDEX) contracts, and the settlement of imbalances. Electricity suppliers and large consumers can buy and sell power on electricity markets, but traders are also active there: these parties do not deliver to consumers but aim to make profitable transactions on these markets.

Consumers

Consumers are defined as the end-users of electricity. Consumers of electricity can be roughly divided into two groups: small- and large-scale consumers. Small-scale consumers are most often households or small businesses with regular connections to the grid, who purchase their electricity from electricity suppliers. Large-scale consumers can choose to have an electricity supplier or purchase their electricity from the market. One key element of the unbundling of the electricity sector was freedom of choice: consumers are free to choose their electricity supplier.

7-2 Regulations & supporting instruments

This section will analyse the current regulations and incentives for utility-scale battery systems and DSOs and look ahead to possible new regulations and incentives.

7-2-1 Regulations

There are four main sets of regulations to consider when looking at battery systems and DSOs: the current Dutch electricity law, the draft of the new energy law, the EU regulation 2019/943 and EU directive 2019/944[2].

All these regulations will be analysed regarding three subjects that touch upon the topics covered in this thesis:

- The rules they pose on owning and operating storage systems;
- The tasks they determine for DSOs;
- The incentives they provide for DSOs to ensure they fulfil their tasks efficiently.

The electricity law

Currently, the Dutch electricity system is governed by the 1998 Electricity law. This being a rather outdated law compared to the current energy system, there are no provisions referring to batteries or storage directly (Rijksoverheid, 1998).

[2]The difference between EU regulations and directives is crucial: EU regulations are binding legislative acts for all countries, immediately after they are passed by the European Commission. EU directives set out specific goals that each country should achieve, but individual countries have to make their own laws to reach these goals. Directives are only binding in a country after a national law has been devised for them.

However, there are strict rules on what the TSO and DSOs can and cannot do. The main task of DSOs is to transport and distribute electricity and to create and maintain connections to consumers and other networks. In fact, when a party (either a generator or a consumer) requests a connection to the network in a certain place, a DSO is obliged to create that connection within a reasonable period of time. In cases where the DSO can prove there is no network capacity available for the connection, the DSO has to report this to the ACM and develop the necessary measures to ensure a connection can be made in the future.

The electricity law explicitly places all responsibility for system operations with the TSO, and not with the DSOs. System operation tasks can be interpreted in a broader way, and this could give the TSO more freedom to experiment with novel technologies than the DSOs have. In 2015, a new governmental decree[3] was issued for experiments with decentralised renewable electricity generation[4] (Ministerie van Economische Zaken, 2015). This decree defines a pathway for network operators or other stakeholders in the electricity system to request permission from the Ministry to deviate from the electricity law to experiment with decentralised renewable generation. However, a recent evaluation by the State Secretary for Economic Affairs and Climate Policy stated that the decree has only led to 5 experimental projects, none of which have led to remarkable innovative breakthroughs (Yesilgöz-Zegerius & Ministerie van Economische Zaken en Klimaat, 2021).

Incentives for the TSO and DSOs have been designed to stimulate efficiency, safety and cost-effectiveness. Because the network operators have monopoly positions, incentives are designed to mimic competition. The main incentive in place for DSOs is their level of allowed revenue. This allowed revenue is determined by the ACM, in different phases. First, every 3 to 5 years, method decisions are published. These method decisions explain how the ACM will calculate the allowed revenue. In the same time period, the x-factor decisions are published. These decisions are made for each network operator and measure how efficient the operators are compared to one other. Finally, annual tariff decisions are published, which establish the final allowed revenues for each network operator. These allowed revenues are then translated into tariffs by the operators: the annual total of their tariffs will add up their allowed revenue. The regulations for setting tariffs are published annually in the tariff codes (Authoriteit Consument en Markt, 2021).

The tariffs consist of two main parts: connection tariffs and transport tariffs. Connection tariffs are present for both consumers and generators and consist of a one-off connection tariff and a periodic connection tariff. These tariffs are based on the costs of the new connection to the existing grid. Grid upgrades in higher network levels (which might be necessary due to capacity constraints) are not included in these tariffs but in the transport tariffs. (Droste, 2018)

The transport tariffs consist of three parts: the transport-dependent tariff, the transport-independent tariff and the tariff for transport of reactive power. The division of costs over these three tariffs has been drawn up in article 3.2.2 of the Tariff Code (Authoriteit Consument en Markt, 2021). The main elements of each tariff are explained below.

- The transport-dependent tariff is the largest share of the transport tariff. It covers all costs related to the transport of electricity and all costs that increase with increasing volumes of electricity transported. The main costs included are the upkeep and

[3] In Dutch: Algemene Maatregel van Bestuur
[4] 'Besluit experimenten decentrale duurzame elektriciteitsopwekking'

expansion of the network infrastructure. Infrastructural expenses benefit the whole network, and because of that, these expenses are divided over all connected consumers (CE Delft, 2016). The transport-dependent tariff is calculated on a monthly basis. It depends on three variables: the monthly volume of electricity transported (kWh), the contracted transport capacity ($kW_{contracted}$) and the maximum measured transport capacity (kW_{max}) during the month. Producers do not pay this tariff; only consumers do.

- The transport-independent tariff is based on the costs network operators have that are not directly related to the volume of electricity transported. Examples include customer service and administration. Both producers and consumers pay transport-independent tariffs.
- The reactive power tariff is only charged to consumers with an unbalanced ratio of active power consumption (kWh) and reactive power consumption (kVah). This is not a common occurrence, and not all network operators charge the tariff.

Note: for small consumers, all tariffs are compounded into a single tariff for connection and transportation, independent of the volume of electricity they consume.

EU regulation 2019/943

EU regulation 2019/943 is part of the clean energy package and provides new market rules that will ease the integration of renewable energy in the combined electricity market. It entered into force on the 4th of July 2019 and was immediately binding in all member states.

The legislature puts some emphasis on storage: it is mentioned in 14 out of the 71 articles. The main reason for the inclusion of storage in so many articles is to provide a level playing field for the different technologies that may enhance the integration of more renewable electricity into the European energy system. The core of the entire regulation package is that all pricing and incentives should be market-based and non-discriminatory, and therefore a level playing field is essential (Art. 22). In remark 39, it is mentioned explicitly that *"Network tariffs should not discriminate against energy storage .."* and in Art 3.j *"Safe and sustainable generation, energy storage and demand response shall participate on equal footing in the market, under the requirements provided for in the Union law"* (The European Parliament and the Council of the European Union, 2019b).

The tasks of the TSO and DSO remain largely unchanged. However, one interesting aspect for DSOs is that the document calls for creating a European entity for distribution system operators, an EU DSO, ensuring efficiency, transparency, and representativeness among the DSOs in the EU. Furthermore, TSOs and DSOs are only allowed to own and operate storage systems under stringent, pre-specified conditions: *"(a) no market-based alternative is available; (b) all available market-based resources have been used; (c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or (d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action*

plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8)." (The European Parliament and the Council of the European Union, 2019b).

The incentives for TSOs and DSOs also remain largely unchanged, but again special attention is given to creating a level playing field for all technologies. It is stated that the basis of charges applied by network operators have to be cost-reflective, transparent, take into account the need for network security and flexibility and reflect the actual costs incurred. They also have to be applied in a non-discriminatory manner, as stated in Art. 18: *"The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response."*. The same article also dictates that distribution tariffs should stimulate DSOs to operate and develop their networks in the most cost-efficient way possible, including through the procurement of services.

EU directive 2019/944

EU directive 2019/944 was also part of the Clean Energy Package and entered into force on July 4th, 2019. It should have been implemented in national regulation by December 31st, 2019, but the Netherlands has not implemented the directive yet. The directive aims to improve the EU regulatory framework that governs the internal electricity market. The directive defines the tasks, rights and responsibilities of all parties in the electricity markets. Compared to EU regulation 2019/943, it is more focused on the consumer and their rights. One of the main objectives of the directives is formulated as follows: *"Using the advantages of an integrated market, this Directive aims to ensure affordable, transparent energy prices and costs for consumers, a high degree of security of supply and a smooth transition towards a sustainable low-carbon energy system."* (The European Parliament and the Council of the European Union, 2019b).

Storage is a recurring element in the directive: it is mentioned in 17 out of 74 articles. There are two main focus points in the mentions of storage: provisions for enabling active customers to own and operate storage, and provisions for TSOs and DSOs that operate storage or request storage capacity from the market.

Article 15 states that active customers that own an energy storage facility should not be subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators. However, in the Netherlands, these double charges do occur in some cases: the tax on electricity is applied twice for stored energy. The first time when storage systems buy electricity to store, and for a second time when the end-user buys electricity that has been stored.

In the specification of the tasks and incentives set for the TSOs and DSOs, there are two main focus points regarding storage. The first is described in Article 32, which is about incentives for the use of flexibility (including storage) in distribution networks. This article poses that member states should provide the right regulations to enable TSOs and DSOs to procure flexibility services, including congestion management, to improve efficiencies in the operation and development of the distribution system. It states that TSOs and DSOs should be allowed to choose flexibility services over network upgrades, if they are cost-effective compared to upgrades: *"In particular, the regulatory framework shall ensure that distribution*

system operators can procure such services from providers of distributed generation, demand response or energy storage and shall promote the uptake of energy efficiency measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system. Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion".

The second focus point is in which situations TSOs and DSOs are allowed to own and operate storage facilities. As a general rule, they are not (Art. 36: "*Distribution system operators shall not own, develop, manage or operate energy storage facilities.*"). However, there is one exception to this rule: when the energy storage facilities are Fully Integrated Network Components (FINC). All of the following requirements should be fulfilled:

- After a tendering procedure, other parties could not deliver the service at a reasonable cost and in a timely manner;
- the storage facilities are necessary for the DSO to fulfil their obligations for the efficient, reliable and secure operation of the distribution system and the facilities are not used to buy or sell electricity in the electricity markets;
- the regulatory authority has assessed the situation and granted approval.

These conditions are aligned with the conditions set in EU regulation 2019/943.

Draft version of the new energy law

The main goal of the new Dutch energy law was to consolidate and update the previously separate electricity and gas laws. In addition to that, once the European Commission designed EU directive 2019/944, the new energy law was also to be used to integrate the directive into Dutch law. The changes made to the electricity- and gas laws to combine them in one updated energy law can be summarised in six key pillars (Ministerie van Economische Zaken en Klimaat, 2020). Of these six pillars, the following three contain elements that are relevant to this research:

- Pillar 1 strengthens the framework for further integration of the energy system, combining the gas and electricity systems. To do so, the tasks and responsibilities of all relevant actors are clarified.
- Pillar 3 is aimed at improving transmission and distribution systems to support the energy transition. It contains updated legislation on the operating framework of network operators, the tasks and responsibilities of network operators, and the methods for tariff determination.
- Pillar 4 aims to integrate new market initiatives, with a particular focus on active customers, local energy communities and aggregators.

Regarding storage systems, the relevant passages from EU directive 2019/944 have been included in the new energy law. However, when comparing the EU texts and the Dutch version, there is less attention for storage systems in the Dutch legislation (Minister van Economische Zaken en Klimaat, 2020).

In the specification of tasks and responsibilities for the TSO and DSOs, included in pillars 1 and 3, there are two changes relevant to this thesis. Firstly, the connection and transportation obligations are toned down slightly: the TSO and DSOs can deny a connection if they can prove there is insufficient transport capacity. In addition, they are obliged to offer information on the required upgrades and alternative locations for the requested connection (Art 3.4.2 and Art. 3.4.3). The second change is that when considering network upgrades, the TSO and DSOs must also consider alternative solutions, including procurement of electricity- or capacity services (Art 3.4.2) (Minister van Economische Zaken en Klimaat, 2020).

When regarding the incentives for the TSO and DSOs, the new energy law is in agreement with the EU regulations that all tariffs should be transparent, non-discriminatory and reflect the costs incurred by the TSO and DSOs from executing their tasks. A new tariff code needs to be designed by the ACM in consultation with stakeholders. This process is likely to take several years, as every stakeholder needs to be consulted.

7-2-2 Supporting instruments

Currently, the number of supporting instruments for energy storage systems in the Netherlands is quite limited. Subsidies and other support mechanisms which are easy to obtain would increase the likelihood of increased volumes of battery storage becoming connected to the grid in the Netherlands. The instruments currently available are the following:

- **Demonstration Energy and Climate Innovation (DEI+)**, which has a category 'flexibility for the energy system'. This category includes stimulating the storage and conversion of renewable energy (Rijksdienst voor Ondernemend Nederland, 2020). This subsidy can cover 25% of the total project costs, up to €15 million. For example, the 12 MW battery system developed by GIGA storage in 2020 received €2.6 million support from the DEI+ subsidy scheme (GIGA Storage, 2019).
- **Energy-investment tax deduction (EIA)**, which allows companies that invest in CO_2 reduction measures, energy-efficient technologies and renewable energy to deduct almost half of the investment costs from their fiscal profit before taxes. Lithium batteries, NaS batteries and redox flow batteries are included in this subsidy (Rijksdienst voor Ondernemend Nederland, 2021a). However, most battery companies are still scaling up and will not benefit from this scheme as they are not often turning a profit yet. This subsidy is particularly interesting for established companies that want to invest in batteries.
- **Renewable Energy Transition (HER+)**, which stimulates projects that will realise a CO_2 reduction by 2030 and will reduce future subsidy costs. The new (+) version of the scheme was recently opened, in which a category is present for 'systems that combine the generation and storage of renewable energy' (Rijksdienst voor Ondernemend Nederland, 2021b). Battery operators have indicated they think they should be eligible, but no battery projects have received it yet.

7-3 Owner and operator use cases

All stakeholders discussed in section 7-1 (except for the regulator) could theoretically benefit from owning and operating a battery. There are many different use cases that would be beneficial to the stakeholders. During the ten interviews conducted, stakeholders were asked about relevant use cases for battery systems in the Netherlands. The different use cases and ownership-situations discussed during the interviews have been included in the table on the next page. This overview of owners and use cases is not exhaustive: only the cases mentioned by stakeholders during the interviews were included. For an overview of the interviews conducted, see appendix D. It is important to take into consideration that currently, TSO and DSOs are not allowed to own and operate batteries in most situations. Those situations are included in the table, because they were discussed in the interviews. The use cases that are currently not allowed are marked with an asterisk *.

The table on the next pages aims to give a concise overview of the use cases discussed by first defining the stakeholder owning and operating the battery and then the intended use case. Conclusions drawn from the information included in the table will be discussed in the next section. When looking at the table, the third column specifies the incentives currently in place for this battery use case. The fourth column indicates if there are already examples of this owner/operator - use case combination in the Netherlands. The numbers refer to the examples given in table 7-1. The fifth and sixth columns assess the impact of this owner/operator - use case combination on the national energy system and the regional network where the battery is located. Conclusions for both these columns were drawn from qualitative discussions during the interviews. The final column highlights interesting elements of the use case that came to light during the interviews or explains why a certain impact score was given in the fourth and fifth columns.

Table 7-1: Table with examples corresponding to numbers in 'Example in NL' table on the following page. The Vattenfall and Greenchoice batteries both reduce curtailment and provide balancing services.

Number use case table	Battery system example in place	Source
1	Greenchoice Hartelkanaal battery	(Greenchoice, 2019)
2	Greener power solutions	(Greener Power solutions, 2021)
3	GIGA storage Rhino battery	(GIGA Storage, 2019)
4	GIGA storage Rhino battery	(GIGA Storage, 2019)
5	Vattenfall Haringvliet battery	(Vattenfall, 2020)
6	Eneco delivers Tesla Powerwalls to consumers	(Eneco, 2017)
7	Shell used a battery to create a new fast-charging station in Zaltbommel	(Alfen, 2020)

Owner/Operator	Battery use case	Incentives in place	Example in NL (See table 7-1)	Impact on national energy system	Impact on regional network	Comments
TSO or DSOs	Reduce need for grid upgrades*	Grid upgrade costs, but those are often lower than battery system costs	-	+	+	Some DSOs mentioned they do not like the risk of being dependent on another party for their network stability. Others see the possibilities for 2030 for places where grid upgrades are very expensive or challenging. They stated they would want to be able to control the battery themselves (Liander, Stedin).
	Use during grid renovations or upgrades	No system yet	-	o	o	Could be attractive for network renovations in neighbourhoods with high shares of rooftop solar panels: their power needs an outlet during disconnections. Now a large resistor is used, a battery is estimated to be useful from 20% buildings with solar panels in a neighbourhood (Liander).
	Temporary while waiting for grid upgrade	No system yet	-	+	+	The business case could work by using the battery for multiple locations in a row. Some network components are becoming scarce, causing longer upgrade lead times. Delivery of transformer parts used to take 6 months, and now takes more than 12 months (Stedin).
	Reduce curtailment*	Costs of curtailment	-	+	+	Curtailment issues varied widely per DSO. There was disagreement over remuneration for curtailment and therefore over the value of batteries in this use case (Liander, Stedin, Enexis).
	Reduce local congestion*	Congestion management costs	-	+	+	DSOs stated this needs to become a market service, several stakeholders implied they would be interesting in delivering this service at the right price (GIGA Storage, Liander, Stedin).
Generator	Reduce curtailment	Negative market prices	1	+	+	Generators stated batteries are still too expensive for viable business cases for curtailment. One generator stated that in reality, generators owning batteries would take double advantage of negative prices both by charging the battery and curtailing generation at the same time (Vattenfall, Greenchoice).
	Lower connection capacity	Connection costs	-	+	+	Not a cost-effective use case yet, but this could become interesting now that in large areas in NL it is becoming harder to connect new generation capacity (Alfen, Greenchoice).
	Defer supply to higher priced moments	EPEX prices	-	+	+/-	Positive impact on national system: higher priced moments will mean more demand and less supply so the battery will balance the system. Regional systems impact unknown: national prices contain no explicit information on regional network circumstances (Liander, Greenchoice).
	Imbalance management	Imbalance prices	-	+	+/-	Positive impact on national system: high imbalance prices will cause battery to balance system. Regional systems impact unknown: imbalance prices contain no information on regional network circumstances. Several stakeholders indicated they expect imbalance prices to rise drastically over the next decade (Liander, Vattenfall).

Impact scores: + = positive, o = neutral, - = negative, +/- = unknown (can be either positive, neutral or negative at different times)
Examples in NL: numbers correspond to table 7-1 'Examples in NL'

Electricity supplier	Portfolio management	Imbalance prices	1	+	+/-	Impact on national system: positive because balancing service. Regional system: unknown impact because imbalance is uncorrelated with local conditions. Several stakeholders indicated they expect imbalance prices to increase drastically over the next decade, the business case will turn positive then (Vattenfall, Stedin).
	Mobile storage (instead of diesel generator)	Regulations on diesel generators	2	o	o	Increasingly strict regulations on using diesel generators in cities make this a growing use case (Liander).
	+ All trader use cases					Most electricity suppliers are also traders and could benefit from those use cases as well. See use cases below.
Electricity trader	Arbitrage trading on electricity markets	EPEX prices	3	+	+ or +/-	Positive impact on national system: high priced moments will often be during low supply and high demand times, and the battery will balance the system. Regional system impact unknown: there is a correlation between regional generation and EPEX prices, but it is not 100% and DSOs noted they cannot count on that effect unless it is a 100% certain (Alfen, Energy Storage NL).
	Arbitrage trading on imbalance markets	Imbalance prices	4	+	- or +/-	Positive impact on national system because battery will increase system balance. Regional system: unknown or negative impact, the imbalance market is very stochastic (related to forecast errors) and not correlated with regional grid situation (Greenchoice, Liander).
	Providing system balancing services (FCR, aFRR, mFRR)	Remuneration for services	5	+	- or +/-	Positive impact on national system because battery will increase system balance. Regional system: unknown or negative impact, system services are very stochastic (related to forecast errors) and not correlated with regional grid situation. National market could be totally opposite from regional situation (Vattenfall, Liander, GIGA Storage)
	Flexibility services	GOPACS, private local agreements	-	o	+	There is no incentive system in place (yet), but batteries could join GOPACS. The contractual term for congestion management is often too short to return a positive business case for batteries (GIGA Storage, Stedin).
Consumer	Small-scale: home storage	Net metering ('salderen') phased out after 2031	6	+	+	Liander expects the business case for home storage to turn positive around 2030. The phase-out of net metering for consumer generation will boost this use case (Liander).
	Large-scale: reduce connection size	Connection tariffs or local unavailability of connections	7	+	+	Not a cost-effective use case yet, but it could become interesting now that in large areas in NL it is becoming harder to connect new large loads (Alfen, Liander).

Impact scores: + = positive, o = neutral, - = negative, +/- = unknown (can be either positive, neutral or negative at different times)
Examples in NL: numbers correspond to table 7-1 'Examples in NL'

Conclusions owner and operator use cases

This section will discuss the main findings from the interviews, as presented in the table on the previous pages. For each possible owner and operator of the battery system, the most likely battery use cases mentioned during the stakeholder interviews will be discussed, as well as the impact this use case could have on both the national energy system and the regional networks.

TSO or DSOs

Five different use cases were identified for battery systems owned and operated the TSO or the DSOs. Because the TSO and DSOs main concern is securing power supply and ensuring sufficient network capacity, all five use cases considered have a neutral or positive impact on both the national energy system and the regional network. However, the TSO and DSOs are not allowed to own and operate battery systems, unless they are a Fully Integrated Network Component (FINC). Therefore, regarding the battery use cases *reduce grid upgrades*, *reduce curtailment* and *reduce local congestion*, it is likely operators will ask market parties to provide these services[5]. Two interesting use cases are the temporary ones: *use during grid upgrades*, or *use as a temporary solution while waiting for a grid upgrade* in a certain area. Both boast the significant advantage that the battery can be used for multiple consecutive locations, and the regulations for temporary solutions are still unclear and therefore possibly less strict. Regarding *use during grid upgrades*, Maarten Afman (Sr. Business Analyst, Liander) stated that they are investigating using batteries during grid renovations in neighborhoods with a lot of solar PV installed on rooftops. The battery system can replace a traditional diesel aggregate, and also provide an outlet to the power generated by the solar panels[6]. Liander has concluded that this use case would be beneficial for neighborhoods where >20% of homes has installed solar panels.

The second temporary use case, *use while waiting for a grid upgrade*, was discussed during all three interviews with DSOs[7]. All agreed that grid upgrades often take (too) long, causing them to refuse new connection requests in certain areas for years on end. Arjan van Voorden, expert asset management at Stedin, emphasised the long lead times for grid upgrades: "We're not Bol.com, you cannot order something and expect it to arrive tomorrow". He also predicted that there will be a drastic rise in the necessary grid upgrades over the coming decades, likely causing shortages in components (mainly transformers) and skilled personnel, and leading to even longer upgrade times. Battery systems could provide temporary extra capacity to these constrained network locations, and facilitate space to connect additional consumers or producers. Greener Power Solutions, a battery company, is already providing this service for larger low-voltage connections in the Netherlands[8] (Greener Power Solutions, n.d.). Afman (Liander) stated that Liander is looking into using larger battery systems as a temporary solution while planning grid upgrades, but they have not worked out detailed plans yet.

[5]The case of an electricity trader providing these services to a DSO will be discussed in the electricity trader section.

[6]They currently use large resistors to discard the power that cannot be transported during renovations.

[7]Stedin, Enexis and Liander

[8]Their battery is relatively small at 336 kWh / 318 kVA.

Generator and electricity supplier

The generator and electricity supplier categories are discussed together, because all interviewed generators are also electricity suppliers. Four use cases for generators were discussed during the interviews, and two for suppliers (excluding the electricity trader use cases). The generator & supplier Greenchoice has a functioning example for the use cases *reducing curtailment* and *portfolio management*: the 10 MW/10MWh Hartelkanaal battery. Maurice Koenen (Sourcing & Portfoliomanagement at Greenchoice) stated stated that for Greenchoice, the aim of the project was to learn how to operate the system optimally, and that the business case for the battery system was risky and not bankable because the revenues were not guaranteed. Both interviewed suppliers (Vattenfall and Greenchoice) indicated that it is highly favourable for them to co-locate battery systems with generation, because of the current tariff structures. In the current structures, batteries are regarded as both a consumer and a generator. Because the consumer-tariff is partly based on the peak capacity used in a month, kW_{max}, and batteries are likely to run a few high-powered cycles each month, the tariffs for stand-alone battery system run high. However, when a battery system is co-located with a generator and only charges from that generator, it can be connected to the larger network as a generator (and not as a consumer), which results in large tariff savings.

For the use cases *defer supply to higher priced moments*, *imbalance management* and *portfolio management*, the impact a battery system has on the national energy system versus the impact it has on the regional network can be contradictory. As these use cases are also available to electricity traders[9], this contradiction will be explained in the next section.

Electricity trader

Four different electricity trader use cases were identified in the interviews. The first three, *arbitrage trading on electricity markets*, *arbitrage trading on imbalance markets* and *providing system balancing services (FCR, aFRR, mFFR)*, all have a positive impact on the national energy system, but not always on the regional network. The first use case, trading on electricity markets, is expected to pose the least risks for capacity overloads in congested regional networks, because there is some relation between national electricity prices (EPEX) and the loads on regional networks. It is likely that high-generation moments, EPEX prices will be low and batteries performing arbitrage will charge - effectively balancing the regional networks. However, Afman (Liander) stated that DSOs cannot count on this synchronicity: they need certainty when planning their network upgrades.

The three DSOs interviewed all raised their concerns about the increase in FCR-providing battery systems. Maarten Quist (GIGA Storage) stated that providing FCR services is currently the most reliable way to operate a battery profitably in the Netherlands, and he expects to see more systems installed in the future. Ferdinant Visser (Alfen) confirmed that most of Alfen's clients purchase systems to provide FCR-services, likely because participating in this market delivers a relatively high and predictable source of income. All three interviewed DSOs emphasised how this causes problems for regional networks: the national system balance, which is maintained through the FCR market, is very stochastic in nature and related to forecast errors in supply and demand. Therefore, there is no apparent correlation between

[9] and electricity suppliers are often traders too

the load on regional networks and the current FCR market prices, as there might be for EPEX market prices. Furthermore, there is no incentive for parties operating FCR-providing battery systems to collaborate with DSOs to find a network-optimal location for their battery: commercial parties will tend to choose their location based on cost factors. Ton van Cuijk (Senior DSO Architect, Enexis) explained the contradiction in rural and urban connections: land prices are generally lower in rural areas, enticing commercial generators or traders to place their systems there. However, networks in rural areas tend to have a lower capacity than in more densely populated areas, because of historically lower loads. This causes problems for DSOs having to connect high-powered systems in these areas, especially when these systems react to (stochastic) national markets.

The use case that could be a solution for congested regional networks is indicated as *flexibility services*. Battery systems owned by traders could provide the market-based services DSOs want and need, but are not allowed to perform themselves, such as *reducing local congestion* or *reducing grid upgrades*. The recent EU regulation and directive empower DSOs to procure these services, if cost-effective. All three interviewed DSOs see a large potential for requesting flexibility services from the market in the future, possibly through tenders or their recently developed system GOPACS. GOPACS is a platform for the DSOs and TSO to request flexible capacity (either upward or downward) in times of congestion. Parties can state their bid for flexible capacity, and the network operators can choose to activate at this price. While this system seems potentially useful for integrating flexible capacity from batteries, market parties providing battery services (Alfen, GIGA Storage) have indicated that the current set-up around short-term bids and contracts places too much market risk on the battery owner for the business case to be attractive. A system with more long-term contracts would decrease risks for battery operators, and mitigate difficulties obtaining financing. Another element standing in the way of DSOs procuring flexibility services is their reluctance to rely on third parties for their security of supply. Van Voorden (Stedin) stated that as a temporary solution, relying on a third party could work. However, if they were to procure permanent flexibility services instead of upgrading (part of) a network, long-term reliance on a third party could be a serious risk for the DSO.

Consumer

For the two main types of consumer, small-scale and large-scale, two different use cases were identified. Both of these use cases have a positive impact on the national energy system as well as on regional network loads. Small-scale consumers, mostly households, could benefit from *home storage systems* in the future. With the phasing out of net metering of home-generated renewable electricity, the business case for home storage systems is improving. Afman (Liander) stated that Liander expects the business case for home storage to become viable around 2030. For large-scale consumers, battery systems could be useful to *reduce their connection size*, either to reduce connection tariffs or because larger connections are unavailable due to network constraints. The business case of using a battery to reduce connection tariffs is not profitable (yet), but large-scale consumers that could not get a large enough connection within a reasonable amount of time have started to consider battery systems to increase their connection size. One example of this is the collaboration between Shell and Alfen in Zaltbommel: Shell needed a larger connection than available to power their fast-chargers, and solved this problem with a 350 kWh battery system (Shell, 2021).

7-4 Barriers

During the interviews, many parties spoke of potential business cases for utility-scale battery systems in the Netherlands, and several opportunities were identified. However, those opportunities are not easy to realise (yet). During the interviews, seven barriers have been identified that hinder the further implementation of utility-scale battery energy storage systems in the Netherlands. At least three parties confirmed all barriers in the following section. An overview of the interviewed parties can be found in appendix D.

1. **Double taxation on stored energy**
   In the current Dutch tax system, energy taxation happens on the user side. Battery systems that take energy from the grid are considered users and pay taxes over this energy. However, if they then discharge and feed into the grid and a customer uses this energy, that customer also pays taxes over the energy. This double taxation can cause up to a 20% reduction in a battery operator's revenues (GIGA Storage, 2020).

   There has been recent progress on this matter: the Ministry of finance is evaluating the taxation on energy at the moment. In a recent letter to parliament, the Ministry of Finance announced its intent to eliminate the double taxation on energy storage with a stand-alone large-scale connection as of January 1st, 2022 (Vijlbrief, 2021). However, this is not a done deal: parliament needs to approve of the changes[10].

2. **High transport tariffs**
   As explained in section 7-2-1, large-scale consumers of electricity pay transport tariffs that are partially dependent on their measured 'kW$_{max}$', or their monthly maximum used capacity. Storage systems are considered to be consumers in the current system. Because battery operations often depend on a few high capacity peaks per month, the current transport tariffs can yield highly unfavourable results for battery operators. GIGA storage has shown that transport tariffs can reduce battery revenues by up to 70% in some cases, making the business case unsustainable for battery operators (GIGA Storage, 2020).

   The current solution for most battery operators is to co-locate battery systems with generators and only charge the battery system using the generated electricity: in this way, the battery is not officially connected as a consumer. However, this severely limits their options for supporting the grid at times with low renewable production. Because of the tariffs, it is currently highly advantageous for battery operators to be located at a connection point with both wind and solar generation; in that way, the periods of lower production are minimised.

   Other EU countries have found different solutions to this problem. For instance, in Germany and the UK, operators of storage facilities can apply for exemption from transport tariffs (Bundesnetzagentur, 2014).

[10] On the 21st of September 2021, it was confirmed that the double taxation will be terminated from January 1st, 2022.

3. **High capital costs of battery systems**
   Several stakeholders indicated that the main element barring them from using batteries at the moment is their high cost price. However, all stated they expect this to change in the near future, as (Li-Ion) battery prices have been decreasing at an incredible pace.

4. **Lack of standardised safety requirements**
   When placing a battery, the municipality must grant the required permits. Unfortunately, there is not yet a standardised procedure for this, and safety requirements vary widely per municipality. This makes it difficult for battery owners to anticipate on safety issues, and it can also delay battery placement by several months. Clearer, national standards and regulations for safety and permits would benefit both battery owners and municipalities.

5. **Loss of Guarantees of Origin**
   Producers of renewable energy can guarantee that their energy is renewable by delivering Guarantees of Origin. Electricity suppliers sell these Guarantees at a premium to parties who wish only to purchase green power or get increased subsidies. The organisation that gives out Guarantee of Origin certificates in the Netherlands is CertiQ, and they do not count electricity fed into the grid from batteries as renewable, because they cannot ascertain how the battery was charged. However, most times the battery will have been charged using renewable electricity. By storing renewably generated electricity in batteries, generators can lose their Guarantees of Origin and thus lose this revenue stream. There are workarounds available, such as placing an extra meter and connection point in the system, but this will also lead to increased costs for the battery operator.

6. **Difficulty obtaining financing**
   Because the business model for electricity storage in the Netherlands is still uncertain and highly dependent on the future prices of different electricity markets, it is challenging for owners and operators of batteries to find financing for their projects. For wind and solar projects, this problem was solved by guaranteeing a base price through the SDE subsidies.

7. **Regulations barring DSOs from owning and operating storage systems**
   Some DSOs have indicated that their main barrier is that they are barred from using batteries by regulation, and are only allowed to use batteries under highly specified circumstances. None of the stakeholders saw this changing before 2030, as this is a result of EU regulations. However, they did see opportunities for TSOs and DSOs to request variable capacity in the form of batteries from the market through tenders.

Overall, a common element in most identified barriers is the relative low pace of development for new policies, regulations and tariffs, compared to the current high pace of the energy transition. To quote one of the interviewees: "Laws and regulations are always one step behind reality, but the current lack of speed in updating them is endangering the transition". The next section will give an overview of several dilemmas related to battery systems and the energy transition policymakers face.

7-5 Dilemmas for policymakers

From the overview of use cases presented in this chapter, it can be concluded that batteries are not always a straightforward solution: in some cases, they might be beneficial for one aspect of the power system, but create risks for another. For policymakers working on topics related to the energy transition and battery systems, this can be extremely challenging. This section describes several dilemmas they will face when developing new policies.

Let DSOs own and operate or procure battery system (services)

If DSOs were allowed to **own and operate** battery systems, they could use them to reduce the need for network upgrades or to temporarily relieve congested network areas. The battery would charge during moments of over-capacity generation. However, discharging the battery would be more complicated: by deciding on a moment to discharge, the DSO would become an active participant in the electricity market - compromising its neutrality. This option offers the advantage of letting DSOs choose the location of the battery system, which they can then optimally integrate into their networks.

For DSOs to **procure battery system services** as a measure to reduce the need for grid upgrades or to temporarily relieve congested network areas, new market mechanisms will need to be designed. This system should be based on long-term contracts to be attractive for battery operators as well as the DSOs. To be in agreement with the EU regulations and directives, it should ensure a level playing field between different options for flexible capacity. This option offers the advantage of ensuring the DSO does not become a market player.

Continue net metering or phase out net metering to incentivize home storage

If the **net metering mechanism is continued**, it does not matter for consumers at which time they feed their power into the grid: their benefits remain the same, regardless of the time of the day and the current electricity prices. Therefore, there is no incentive for owners of residential PV panels to invest in home storage systems to defer supply. The main benefit of this option is that it creates an incentive for installing rooftop solar PV.

If net metering is phased out[a], this will **incentivise home storage** because with an increasing share of solar generation in the generation mix, electricity generated around peak solar time will likely be of limited (or zero) value, which will be reflected by EPEX prices. Owners of residential PV panels could still extract value from their generated electricity by storing it for self-consumption at a later time, or for selling back to the market when prices are higher. This option has the potential to help balance the peak in solar PV production.

[a] A gradual phase-out of net metering is set to take place between 2023-2031 (Wiebes & Snel, 2019)

Create an exemption for battery systems from transport tariffs or make no exemptions from tariffs

If battery systems providing grid support functions would be **exempt from (parts) of the transport tariffs**, the business case for these batteries would improve drastically. Germany and the UK have provided exemptions for battery systems, after which they have become more common in their power systems. DSOs are generally not in favour of this idea, because some types of battery systems result in high loads on their networks, for which they feel batteries should pay.

If **no exemption is made**, battery systems will continue to be difficult to finance because of their risky business case. It is likely that the only large-scale battery systems in the Netherlands will used for arbitrage and FCR-services, because these are the most profitable.

Aim for battery systems as a short-term solution or battery systems as a long-term solution

Battery systems could provide **short-term flexibility** for temporarily congested areas or areas where the grid is being upgraded at that moment. The rules and regulations for this application are still unclear, but with support from policy makers, this application could have real potential, especially in the face of the amount of network upgrades that will have to be performed in the future. This option allows the battery system to be used for multiple locations in a row, possibly improving the business case.

Alternatively, battery systems could also provide **long-term extra capacity**, possibly eliminating the need for grid upgrades in some places. This might be a risky bet for DSOs, as they are wary of being dependent on a third party for security of supply. However, in some locations, this solution might be more cost-effective than upgrading the grid.

7-6 The value of batteries in the larger energy system

The research presented in this thesis has been focused on using battery systems in regional networks in the Netherlands. Chapter 6analysed the costs and benefits of implementing a battery system at a specific distribution station in the Dutch MV network, from the viewpoint of the Distribution System Operator. However, (regional) battery systems also carry value for the overall energy system - a source of value that has been disregarded during this research, to limit the scope of the analysis.

The value battery systems can provide to the overall energy system depends on four key questions regarding the energy transition, which will be described below.

What will the future power mix look like? The composition of the future power mix has a distinct influence on the value of battery storage systems. If, as currently expected, solar PV and wind become the dominant sources of electricity generation, the majority of the electricity supply will become variable and weather-dependent (IEA, 2020b). Thus, during moments with low wind and solar PV generation, electricity demand will have to be satisfied by other means. One way to do this is through the traditional (gas) peaker plants[11].

The other way to ensure power system stability in a system dominated by solar and wind production is by integrating large amounts of both long- and short-term storage into the power system (Mulder, 2014). Battery systems are a prime candidate for providing a large share of this crucial short-term storage volume, while synthetic fuels will likely provide long-term storage.

If the middle road is chosen, with both (gas) peaker plants and battery systems providing short-term flexibility, this might lead to a more expensive overall system. Battery systems will be used during the hours where they are at a cost advantage over peaker plants, cutting down on the run time of these plants. Because all fixed costs for maintaining the peaker plants will still need to be reflected in their electricity price, this would likely cause these plants to become increasingly expensive to run.

Overall, the combination of increased solar and wind generation and reduced reliance on peaker plants in the power system will likely increase the value of battery (and other) storage systems.

How will electricity prices develop in the future? Increased generation by solar and wind will likely cause lower or even negative electricity prices during peak production times, when both wind and solar conditions are optimal. However, when solar and wind generation is limited because of weather conditions, electricity prices will increase (Badyda & Dylik, 2017). These larger fluctuations in electricity prices will strengthen the business case for battery storage systems, because these systems will be designed to charge during over-production (at low electricity prices) and discharge during under-production (at high electricity prices). These battery systems can help smooth out the variability in power supply, while also using the arbitrage opportunities present in electricity markets.

Low or negative electricity prices are becoming more common. In the Netherlands, there were 97 hours of negative prices and 791 hours with prices below €15 per MWh (ENTSO-E, 2021), (Visser, 2020). In the future, these price levels are expected to become even more

[11] These plants currently run on natural gas, but could use hydrogen or another 'green' gas in the future.

common. The effects of increased renewable generation have also been witnessed in the Spanish and German markets (Sánchez de la Nieta & Contreras, 2020), (de Lagarde & Lantz, 2018), (Maciejowska, 2020). Research has shown that increased renewable generation in these electricity markets is connected to lower electricity prices and influences the distribution of prices. Lower or negative electricity prices might be used by other market players, such as generators using curtailment or industrials running a flexible production. Storage systems are the only elements of the system that have the ability to benefit from a larger price variability.

Overall, an increase in electricity price variability will strengthen the business case for battery and other storage systems in the energy system.

How much will we 'overplant' and curtail generational capacity? Another possibility to ensure demand is satisfied at all times is to choose a strategy of overplanting and curtailment. In theory, an energy system could develop so much generational capacity that peak demand can be satisfied by instantaneous generation during all moments. When generation is higher than demand (which it will often be), generation capacity would be curtailed. However, this practice would have several serious downsides. First, it would likely not be a cost-efficient solution: a large share of generation capacity would be used very infrequently. Second, enormous amounts of space will likely be necessary to construct sufficient generational capacity. In small and densely populated countries, such as the Netherlands, constructing such an overcapacity of generation could prove infeasible in terms of available space and peoples' willingness to live near solar and wind generators. Third, we might not be in a position to "waste" power. With increased electrification, the Netherlands might reach a point where it urgently needs all generated electricity, and it cannot allow a significant share of generated electricity to go to waste through curtailment.

If large-scale overplanting and curtailment are indeed seen as an unfavourable option, the remaining solution is to develop only sufficient generational capacity to satisfy average loads. In that case, storage systems would be extremely valuable because the peaks in generation and demand do not generally coincide: Dutch households' electricity use typically peaks between 6 pm and 9 pm (NEDU, 2020), while solar PV generation peaks around noon (Energieopwek.nl, 2021).

How much of the network can be reinforced in time? To integrate all additional renewable generation into the electricity network and ensure increasingly electrified demand loads can be satisfied, large parts of the network in the Netherlands will need to be upgraded. According to II3050, 9-14% additional MV/LV stations, 70-90% additional MV stations and 40-50% additional HV stations will need to be constructed by 2050 to ensure a stable electricity supply. Furthermore, an expansion of capacity is necessary at 13-18% of the existing MV/LV stations and 25-45% of HV stations (Gasunie et al., 2021).

The speed at which operators can upgrade the networks is slow compared to advances in the decarbonisation of the Dutch energy system. Network upgrades take time: new HV stations take between 7-10 years to complete, and new MV stations between 5-7 years. The accompanying cabling circuits take anywhere between 2-7 years (Netbeheer Nederland, 2019). To realise sufficient infrastructure by 2050, network operators will have to upgrade HV/MV stations at 7 times their historical speed and MV stations at 3-3.5 times their historical speed[12] (Gasunie et al., 2021).

[12]Compared to 2015-2019 upgrade times.

The availability of space, skilled personnel and components might also pose constraints on the speed of network upgrades. For example, regarding space, it is estimated that approximately 30% of streets Netherlands will have to be opened up between 2030 and 2050 to upgrade the electricity networks (Gasunie et al., 2021). Regarding the availability of skilled personnel, various network operators have expressed on their own websites or through news outlets that they are in dire need of skilled workers (Stedin, 2020), (Enexis, 2020b), (Voerdmans, 2021). For example, Liander indicates that they are currently experiencing delays in realising new connections, both because of a shortage of qualified personnel and scarcity in some materials necessary for the energy transition (Liander, 2021b).

Overall, to reach its renewable energy goals, the Netherlands will not only need to upgrade large parts of the network, it will also need to do so at an unprecedented speed. It appears the network might not be ready in time for all the additional generation and consumption of a decarbonised power system. That will increase the value of (temporary) battery systems: these systems can provide temporary extra capacity to constrained network parts, either while waiting for upgrades or to ensure security of supply during upgrades.

Chapter 8

Discussion

This chapter will summarise and analyse the findings of this thesis. It aims to give an overview of the main research findings and the findings from specific research parts of this thesis. Afterwards, a selection of limitations impacting the results of this research will be discussed.

8-1 Findings

Over the course of this thesis, a wide range of research activities was carried out. The activities were focused on determining the influence of a battery's system location on its value for the Dutch regional power network, but also included gathering the information necessary to understand the relevant aspects of the system. Those findings will be summarised and discussed as general findings in the first section below. Subsequently, results from the battery models and the case study will be discussed, followed by a discussion of the results from the cost-benefit analysis performed during the case study. Finally, the findings of the research into the institutional context of battery systems in the Netherlands will be discussed.

8-1-1 General findings

This thesis is centred around a growing problem for the Dutch power system: increased variable renewable energy generation is causing congestion in power grids. In section 3-1, plans for large-scale renewable electricity generation by 2030 are analysed. It is shown that by 2030, at least 35 TWh of land-based renewable generation capacity will be operational. The dominant sources of renewable generation will be solar- and wind-powered. 70% of electricity generation will be powered by solar and wind in 2030, a stark increase compared to the 13% generated by solar and wind in 2019. One of the most challenging aspects of this growth is integrating renewable generators into the existing power grid. Many developers choose to build their wind and solar farms in areas where land is relatively inexpensive. Traditionally, these are rural places with limited network capacity, and integrating extra generators will

cause those networks to overload. That is why in a significant share of the Netherlands, new network connections for large-scale generators are not available, as shown in figure 1-2. The TSO and DSOs are developing the necessary grid upgrades, but those are time-consuming and expensive. Other solutions include congestion management and curtailment, but those have drawbacks: congestion management is only allowed as a temporary solution, and curtailment 'wastes' electricity and can be expensive for the network operator. Understandably, network operators are looking for other solutions, one of which might be battery systems.

In literature review section 2-2, the increasing deployment of utility-scale battery capacity is demonstrated. Different use cases for battery systems are explained and analysed, and previous research into the most relevant use cases is discussed. An interesting finding from the literature review was that a large share of the literature focused on combining different battery use cases to develop a viable business model for the battery system. There was limited previous research on the influence of system location on the value of battery systems; most research in this area addressed the differences of locating battery systems at households or at one central location. Several studies found that the location of a battery system in the network was important for the network operator and network quality. The last section of the literature review (2-2-3) discussed various modelling approaches taken to operate battery systems optimally. The most common (and relatively fast) method was linear programming, which resulted in choosing a linear-programming based approach for two of the models developed.

8-1-2 Battery model findings

The findings of the different battery models developed and used on the Waalsprong case study are presented in chapter 5-7. These findings can be divided into two main model categories: the model for the large battery, which solves all congestion, and the model for the smaller battery combined with curtailment.

The model for the large battery was simple: the battery was set to charge during times of excess generation load on the substation and to discharge whenever there was capacity for extra generation load. This rudimentary model was intended to prove the existing idea that quite a large battery would be necessary for solving all congestion with a battery. The results confirmed that: for the considered generation scenarios at station Waalsprong, battery sizes of 26-54 MWh were necessary to ensure the loads on the station remained within the station's capacity limits. One key learning from this model is that the connected generator significantly influences the battery size necessary to resolve all congestion. When (some) solar generation is connected, generation follows a diurnal cycle, and the battery will always find moments to discharge. When there is only wind generation connected, long periods of high generation can occur, during which the battery cannot discharge. Because of this, a larger battery capacity is needed for those generators. Combined wind/solar generation causes the lowest volume of excess loads, likely because the solar and wind generator seldom show peak production at the same moment. Therefore, the smallest battery capacity is needed to resolve congestion in that scenario at station Waalsprong.

The models for the battery and curtailment system were more sophisticated: they were linear-programming optimisation models, with the aim to keep the load on the station within the station's capacity limits and minimise the curtailment costs for the network operator during the test year. The difference between the two models was the connection point of the battery

+ curtailment system: for the first, the system was located at the substation, and for the second, it was located at the generator. The results presented in section 5-7-2 show that for the case of station Waalsprong, the aims of the model were achieved: no excess loads were found during the year, and a 10 MW/10 MWh battery + curtailment system was able to reduce curtailment costs for the network operator between 65% and 80% depending on the system location and generation scenario. The most considerable relative reduction in curtailment costs was realised for the combined wind/solar generation scenario and the smallest for the 100%-connected solar. The connection location of the battery and curtailment system had no significant impact on the reduction in curtailment costs. This is likely caused by the way the model was set up: the system was only allowed to curtail generation loads when there was an excess load at the station, so the two connection locations (with the same additional generator) would curtail the same loads, at the same moments.

The developed model reduced not only curtailment costs but also curtailment volume: the 10 MW/10 MWh battery was able to reduce curtailment volume by at least 60% for every system location. The relative reduction in curtailment volume was the largest for the combined wind/solar and wind generation scenarios and the smallest for both solar generation scenarios. This can be explained by the fact that low EPEX prices might coincide with peaks in solar generation, so curtailing solar is often less costly than curtailing wind. This has probably led the model to curtail relatively more solar generation. The location of the connection had no impact on the curtailed volume.

Regarding the combined wind/solar generator results at Waalsprong, it should be noted that initial curtailment for that scenario was already relatively low at a total of 185 MWh, so any (small) reductions will result in large relative changes. In absolute terms, the curtailment costs decreased the most for the wind generation scenario, as did the curtailment volume.

While the model was not designed to steer battery operations on electricity market prices, it did generate an operating profit, defined as the difference between electricity charging costs and electricity discharging revenues. For a 10MW/10MWh battery + curtailment system at station Waalsprong, the annual operating profit ranged between €17.3k for the 100% solar scenario, with the system connected at the generator, and €4.95k for the wind/solar scenario connected at the station. At all locations, both solar scenarios generated the highest operating profits. Again, the most likely explanation lies in the synchronicity of EPEX prices and solar generation. The different system locations did lead to minor differences in operating profit in the case study: for the two solar scenarios and the wind scenario, locating the battery + curtailment system at the generator resulted in significantly higher operating profits. This is likely because when the battery + curtailment system is located at the substation, the battery system reacts to the total station profile and less to the additional generator power. As the total station profile also contains demand loads, this profile is smoothed a bit, leading to less pronounced peaks for the battery system to act upon. Also, the total profile of supply and demand at the substation might not be as in sync with EPEX prices as pure solar or wind generation could be, causing the battery system to charge and discharge at more cost-optimal moments for the generator connection location.

8-1-3 Cost-benefit analysis findings

The results generated by the different battery models were used to perform a cost-benefit analysis between four possible solutions to integrate additional renewables into the power network at station Waalsprong: grid upgrades, curtailment, the large battery solving all congestion and the battery + curtailment system connected at both locations. A comparison between the net present value of these solutions over 50 years resulted in several insights. First of all, as expected, the large battery led to significantly higher costs than all other solutions, because of its considerable size in all scenarios. Secondly, the curtailment solution was the least expensive option for station Waalsprong, but two factors should be taken into account when considering this result. First, curtailment is not a permanent solution under current regulations, as network operators are required to connect generators within a specific period of time. Second, curtailment might be a less desirable solution for society because it is essentially wasting carbon-free electricity. A reflection on this is included in section 7-6.

The CBA also demonstrated that for both considered solar-generation scenarios at station Waalsprong, the battery + curtailment system could result in lower costs for the network operator than grid upgrades. This difference was most pronounced for the 100%-connected solar with the battery system at the generator: grid upgrades were over €600k more expensive than the battery system over the entire 50-year timeline. For the wind and wind/solar scenarios, grid upgrades were less costly than the battery + curtailment system. The system location had some impact on the CBA outcomes for both solar scenarios and the wind scenario: locating the battery + curtailment system at the generator resulted in lower costs for the network operator. This is caused by the system's increased operating profits at this location, as explained in the previous section. It is interesting to see that the cost difference between grid upgrades and the battery + curtailment system increases when the solar generator is connected at 100% instead of 70%: this could indicate that at station Waalsprong for even larger solar generators, which are becoming more common, including a battery in the system might be even more attractive compared to grid upgrades.

In the combination of the CBA analysis and the battery models, the costs of curtailment for the DSO play a crucial role. To analyse the impact of this costs level on the findings, a sensitivity analysis was performed in appendix C-0-1. Results from this analysis will be discussed in section 8-2.

8-1-4 Institutional context findings

The findings from the research into the institutional context for utility-scale batteries in the Netherlands can be divided into two parts: regulatory findings and findings from interviews.

There are four main findings from regulations that influence the value of battery systems for the Dutch (regional) power networks. The first is regarding network tariffs: a storage system is regarded both as a generator and as a consumer under Dutch law, and therefore transport tariffs are levied. However, these depend partly on the maximum monthly measured transported capacity (kW_{max}), which puts batteries used for grid support at a disadvantage. They are activated at full power only a few times during the month, resulting in high overall transport tariffs for battery operators. Battery operators indicated that these tariffs could amount to 70% of their annual revenues. Secondly, an interesting feature of the current Dutch

power system is that network operators have an obligation to connect parties that request a connection. If the requested connection creates the need for (expensive) grid upgrades, they have to plan for those. There is no incentive for parties requesting a connection to do so in places that are advantageous to the network or network operator.

Thirdly, it is clear from the current regulations that network operators are not allowed to own and operate storage systems, unless under very specific circumstances. Section 8-2 will elaborate on the implications that has on this research. Fourth and finally, a new energy law is currently under revision. This law will incorporate the new EU directive on electricity markets and unify and update the old gas and electricity laws. The EU directive and regulation both give ample attention to the possibilities of including storage in the energy system, and put emphasis on creating a level playing field for storage systems - creating more possibilities for storage system operators. However, the draft version of the Dutch new energy law does not emphasise storage that much, and new opportunities for storage operators are less apparent.

During the interview phase, many interesting insights were gathered. There are three that have the most impact on the answer to the main research question and one that is adjacent to this research. First of all, when asked about the difference between locating a battery at a substation (or other points of congestion) or at a generator, battery owners were very clear about the advantage the generator location has for the business case of the battery. Because of the previously mentioned kW_{max} tariff, locating a battery anywhere else than on a shared connection with a generator is highly unfavourable for the business case of the battery, and no battery owner will be inclined to do so. Co-locating with a generator is remarkably beneficial because if the battery only charges from the generator (and not from the grid), it is not regarded as a consumer and will not pay the transport tariffs[1].

Secondly, if the network tariffs were to change in favour of battery operators, both network operators and battery owners see advantages in batteries providing services at congested points in the regional networks. However, a system for local congestion markets is still under development (GOPACS), and contracts through that system are too short-term for battery owners, causing financing issues and high risks.

Thirdly, DSOs do see opportunities for using battery systems on a temporary basis: either to relieve a congested area until a grid upgrade can be realised, or to ensure connectivity during the execution of the upgrades. Using a battery for multiple locations in succession would reduce costs, and short-term use is less strictly regulated than long-term use.

The final takeaway from interviews is not directly applicable to the main research question of this thesis. Still, it does provide an interesting outlook of the different effects utility-scale battery systems can have on the Dutch power system. During the interviews, most parties that were currently operating a battery or were planning to operate a battery indicated that the most reliable business case for batteries in the Netherlands is to participate as Frequency Containment Reserves (FCR) for TenneT. These batteries have a positive effect on the national power system: they provide system balance. However, regional network operators were very concerned by the possible increase of FCR-providing battery capacity connected to their networks. The FCR market and the load on regional networks are not likely

[1] At GIGA Storage, they even constructed an independent microgrid, containing several generators and a battery system. The microgrid is only connected to the main grid at one point and shares the net fees for connection and transportation among all connected parties

to be correlated in the way EPEX prices and the regional network load could be related[2]. Therefore, high-powered FCR delivering batteries connected to the regional network could cause significant strain on the networks. Because of this risk, regional network operators are generally not in favour of changing network regulations and tariffs to accommodate privately-owned battery systems.

8-2 Limitations

This section will discuss the main limitations of the research conducted. It will first reflect on the general assumptions made at the starting point of this thesis. Second, it will discuss the assumptions on which the models were based and analyse their shortcomings. Third, it will reflect on the assumptions used in the cost-benefit analysis and discuss the main results from several performed sensitivity analyses.

8-2-1 Reflection on general assumptions

One of the main assumptions in this thesis is that the network operator has the option to choose to implement a battery system instead of upgrading the network. However, as explained in section 7-2, under current and future regulations network operators are not allowed to own and operate battery systems in most cases. Only a few minor exemptions are present, one of which is if the battery is a Fully Integrated Network Component (FINC), so for the main part of this thesis, the battery system was assumed to be a FINC. During the interviews, network operators stated that they are still unclear on the specific rules for using battery systems as a FINC. One of them had a pilot running but was told by the regulator to shut it down (Liander, 2017).

In reality, network operators stated it would be more likely for them to open up a tendering process, in which private parties could place bids offering flexible capacity, such as battery systems, for specific congested regions. However, some network operators expressed their aversion to the risks they associate with placing the network security and stability in the hands of a private party. Moreover, there is no system (yet) in place for this kind of long-term flexibility tendering procedure. Battery owners indicated they would be interested in delivering such a service, but also stated that they expected flexibility market prices to be too low to compete with high FCR prices. Overall, the assumption that the battery system is owned and operated by the network operator was helpful in simplifying different parts of the analysis, but it is not the most likely scenario for the future.

The next general assumption this thesis was built upon is that findings from the Waalsprong case study might be applied to similar MV stations in the Netherlands. Compared to the two other stations with available data (see section 5-1), Waalsprong seemed the most representative, but it is hard to be certain of that without a larger number of stations to compare. One possible difference between station Waalsprong and other MV substations in the Netherlands is that Liander has been experimenting with a (small-scale) flex market project there. However, Liander looked into this and concluded impact would be relatively small: they

[2]High regional generation on sunny or windy days will likely cause low prices, and thus lead price-steered batteries to charge and balance the regional network at the same time.

saw a maximum of 0.8 MVA being fed into the grid during times of peak demand, and this thesis focused on times of peak generator. Another element that could make the case less representative is that all data was gathered for the year 2020, which was quite an unusual year (global pandemic). To account for this effect, Liander looked into changes with regards to 2019, and reported that changes at station Waalsprong were minimal: the station connects mainly households and generators, so no large-scale (industrial) power consumers were suddenly turned off at the start of the pandemic. Finally, when considering translating the findings from station Waalsprong to other stations, the division of the total load from consumers and generators should be taken into account: differences in these profiles can alter the results. If a station's load is mainly from consumers, and peak loads are caused by peaks in consumption, the discharging moments of the battery will become more important than the charging moments. At station Waalsprong, generation was the dominant cause of peak loads.

Another crucial general assumption underlying this research is about the total energy system it was conducted in. The research was focused on the effects in regional networks, but these networks are always a part of the larger energy system. Thus, the research was conducted within the settings of the current Dutch (and European) energy system, although effects on the larger system were not taken into account. Currently, the total energy system is on the brink of large disruptions because of the energy transition. Systemic changes in the energy system could drastically alter the dynamics of loads, networks and the case for battery systems. A few key elements of possible system changes in the energy system have been discussed in section 7-6, including their impact on the value of battery systems. The composition of future power systems and the ensuing electricity market prices will have a consequential effect on the findings reported in this thesis.

Zooming out, there is one other general assumption this thesis makes: that it is essential to solve the problem of limited transport capacity. It is only problematic to curtail power if there is also unsatisfied demand for power at another place or time. If this is not the case, the 'saved' electricity becomes worthless to society.

8-2-2 Reflection on modelling assumptions

In appendix A-4, a section on the validation of the MATLAB models has been included. This section will discuss the main assumptions of the models and the limitations ensuing from those assumptions.

For both the excel model and the MATLAB models, one central assumption was made to simplify the work: the assumption of perfect foresight. All models presume perfect knowledge of the network capacity conditions, generator loads, and consumer loads is available. In reality, this is obviously not the case. Certain elements, such as solar generator loads, are quite predictable, but others are less so. At the moment, network operators are upgrading their measurement systems to gather more accurate network data and see network congestion developing in (almost) real-time. For the findings of this thesis, the perfect foresight assumption is relevant: grid upgrades do not require perfect foresight to work effectively, but the developed battery + curtailment system does. However, with advanced measurement systems and weather forecasts, developing a steering system that functions well might be possible.

The second large modelling assumption is that the battery system is not entirely steered by price signals for charging and discharging but by the costs of curtailment. As explained in the

previous section, this goes out from the assumption that the battery is a FINC, owned and operated by the network operator. If, in reality, the battery were to be operated by a private party, this party would surely take market prices into account for the charging schedule of the battery. The network impact of the battery system would change drastically in that case, depending on which markets the battery system participates in.

The third element limiting the accuracy of the developed models are the expected EPEX prices. For predicting a full year of EPEX prices, the CE Delft PowerFlex model was used, as described in section 2-1-1. One main limitation to this model is its tendency to predict extremely low prices for moments of high generation and low demand - which are also likely moments of congestion in the networks. These extremely low prices have been corrected to a minimum of €-10 per MWh, but this has introduced a large uncertainty, as lower prices might occur during a few moments in the year, and it is unknown whether the artificial price floor of €-10 has been set at the correct level. Suppose the actual price floor would be lower. In that case, the battery + curtailment systems might reduce curtailment costs even further, as curtailment or battery use often happens during moments of high generation and low prices. On the other hand, if the actual price floor is higher, the inverse might be true. In general, predicting power prices is challenging and will always lead to inaccuracies.

The fourth large modelling assumption relates to the generator loads. All generator loads were constructed using 2020 weather data to ensure their compatibility. However, weather conditions vary throughout the years, which could lead to different results. Finally, the developed models were high-level battery operation models: they did not include specific power line modelling for the battery and network cables. Only overloading on the substation was considered to cause congestion. A maximum capacity was set for the cable connecting the battery to the network, but no other power effects (such as cable losses) were taken into account.

8-2-3 Reflection on CBA assumptions

During the cost-benefit analysis, numerous assumptions were made to simplify the considered systems enough to compare them. First of all, the largest source of error stems from the 50-year time period used for all CBA analyses. To generate results for the full period, the annual model results from the test year were used for all 50 years, without adaptions. As a result, many errors were introduced here: in reality, both consumer loads and generator loads on a substation will grow during a 50-year period. Also, simulated EPEX prices for one full year were used in the battery models, but price patterns will definitely change over a span of 50 years.

The second assumption in the CBA that is likely to diverge from reality is the assumption that the battery is owned and operated by the network operator, and as a FINC, does not incur connection costs and transportation tariffs. If market parties were to deliver the battery system as a service to the network operator, they would face connection costs and high transportation tariffs. This would increase the costs of using a battery system for the network operator. In some countries, such as the UK and Germany, battery systems delivering grid services are exempt from these tariffs. A similar exemption could be made in the Netherlands.

Finally, several parameters were estimated and assumed for the CBA, but if varied, they could influence the outcomes. For these assumptions, sensitivity analyses were made, an extensive

overview of which can be found in appendix C. Results from those analyses will be discussed below.

Curtailment costs
Network operators' estimation of curtailment costs varied over a wide range (between €0 to €600 + EPEX per MWh), and the curtailment costs have a significant impact on the model and CBA outcomes. To account for this, additional analyses were made for two scenarios at station Waalsprong. First, the costs for lost subsidies and Guarantees of Origin were doubled, resulting in curtailment costs of €250 + EPEX per MWh. Second, the costs for lost subsidies were eliminated, and the remaining costs for Guarantees of Origin were set at €7 per MWh[3], resulting in curtailment costs of €7 + EPEX per MWh. This scenario is useful to see what might happen if the SDE subsidies would end in the future.

Figure C-1 in appendix C-0-1 shows the results of doubling the curtailment costs to €250 + EPEX per MWh. All considered solutions and scenarios show that increasing the curtailment costs makes network upgrades more attractive for station Waalsprong. For the wind and wind/solar scenarios, there is a significant difference between the battery + curtailment system and grid upgrades, with grid upgrades resulting in fewer costs. For both solar scenarios, the cost difference between a battery + curtailment system at the generator and grid upgrades has (almost) disappeared, bringing both solutions to the same cost level. An interesting effect occurs for the pure wind generator: curtailment of the wind generation has become more expensive than both grid upgrades and the battery + curtailment system. At the old cost level, curtailment was always the least costly solution for reducing congestion at station Waalsprong.

Figure C-2 displays the results of decreasing the curtailment costs to €7 + EPEX per MWh at station Waalsprong. First of all, curtailing the excess loads has become the most cost-effective solution for all scenarios, as was to be expected. When comparing these results to the results at the original curtailment costs level, two things stand out. First, for solar, the same patterns as in the original CBA are visible: for both scenarios, the battery + curtailment system connected at the generator is more cost-effective than grid upgrades, or a battery + curtailment system at the station. The cost difference between grid upgrades and the battery + curtailment system has grown larger at decreased curtailment costs. Second, for the wind and wind/solar scenarios, the costs difference between grid upgrades and the battery + curtailment system is small, just as in the original CBA. Overall, leaving the subsidy out of the curtailment costs does not change the comparison between the battery and curtailment system and grid upgrades all that much for station Waalsprong – it does put the curtailment solution at a great cost advantage. A more detailed analysis of these results can be found in appendix C-0-1.

Battery system costs
Developing an accurate estimate of current LFP battery system prices is challenging for two reasons: first, battery prices are declining rapidly, so old forecast might not be accurate. Second, battery companies are not inclined to disclose this (sensitive) information. When asked during interviews, battery operators stated that they had signed NDAs with suppliers on the current prices of their systems.

[3]The current price level for wind and solar Guarantees of Origin. The market is very nontransparent, so future prices are hard to predict (Wielders, de Bruyn, Blom, & Conradij, 2020).

In Appendix C-0-2, a sensitivity analysis of the CBA results to include a reduced battery price level is included. When performing the CBA analysis at a battery price 65% lower than the original price (77.4 USD/kWh by 2030, based on the low-price scenario from (IRENA, 2017a)), the results are now very positive for the battery systems. For all generator scenarios, implementing a battery + curtailment system is significantly (almost twice) less costly than upgrading the grid at station Waalsprong. This effect is demonstrated by figure C-3. To further investigate this effect, table C-5 was developed: it shows for which 2030 battery system price (€ per kWh), the battery + curtailment system reaches cost parity with grid upgrades, for every generator scenario at station Waalsprong. The highest (thus most attainable) price level found is €227, for the 100% connected solar generator, with the battery + curtailment system located at the generator. The lowest price level found is €146, for the combined wind/solar generator with a battery + curtailment system located at the station. With the pace at which battery costs are reducing at the moment[4], both price levels are likely within reach for 2030.

Battery system learning rate

It is widely known that battery prices fall every year, however, it is hard to predict by how much. That is why in Appendix C-0-3, a sensitivity analysis on the battery learning rate has been included. The results of this analysis are comparable to the sensitivity analysis at lower battery system costs: increasing the learning rate from 24% per 18 years[5] to 50% per 18 years causes the battery + curtailment system to be less expensive than grid upgrades for all generation scenarios at station Waalsprong.

Grid upgrade costs

Two large assumptions have been made about the grid upgrade costs. First, the costs have been calculated on a per kW basis, while in reality, they will resemble a step function: once the network operator decides to upgrade, he does so by an amount he estimates is large enough to keep the grid unconstrained for the next 50 years.

Second, a certain cost level per kW was assumed. This cost level stemmed from previous analyses by CE Delft and was a generalisation of the average network conditions in all of the Netherlands. It is imaginable that in some locations, grid upgrades are a lot more costly[6]. In appendix C-0-4, a sensitivity analysis of the CBA results to the grid upgrade cost level has been included. Table C-6 contains the total cost level per kW for the required grid upgrade, at which upgrading the grid is at cost parity with using the battery + curtailment system at station Waalsprong. This table shows that if grid upgrades are at least 18% more expensive than the original cost level used, the battery + curtailment system results in equal or lower costs over the considered period for all generation scenarios. While the specific grid upgrade costs for station Waalsprong are unknown, it might be the case that grid upgrades are over 18% more expensive than the national average for several harder-to-reach places in the Netherlands.

Social costs

[4]Between 1992 and 2016, real price per energy capacity fell by 13% per year (Ziegler & Trancik, 2021)

[5]The lifetime of the battery system

[6]One interviewee indicated that he expects grid upgrades for de Waddeneilanden to be too expensive and soon to be replaced by a battery system.

Finally, the cost-benefit analysis conducted did not include societal aspects. A more extensive social cost-benefit analysis (MKBA) would also include costs for CO_2 emissions, environmental effects, quality-of-life effects and many other aspects. In particular, considering the impact of CO_2 emissions could lead to interesting results: when curtailing renewable generation, other generators will have to make up for this, which could result in increased carbon emissions. This effect might cause both battery systems and grid upgrades to become more favourable compared to curtailment. On the other hand, battery systems are made of rare (and sometimes harmful) elements. If no satisfactory recycling system is in place at their end-of-life, environmental and material-use aspects might increase social costs.

Chapter 9

Conclusion

This chapter will present the conclusions drawn from the research conducted during this thesis. To answer the main research question, four sub-research questions were formulated, which were researched during the different phases of this project. First, the four sub-research questions will be answered, and then a final answer to the main research question will be formulated.

9-0-1 Answers to the sub-research questions

Sub-question 1: At which representative system locations can a battery system support the 2030 Dutch regional power networks?
Analysis in the first part of this thesis has shown that by 2030, the dominant generators in the regional networks will be wind and solar. Because of increased wind and solar generation, regional networks are becoming more congested. Solutions for this can be upgrading the network, curtailing the excess generations or decreasing load on the network by integrating a battery system. Different ways of connecting a battery system to the MV grid have been simplified in two setups: a battery system connected at the HV/MV substation and a battery system connected at a generator feeding the substation. In agreement with a regional network operator, the case of substation Waalsprong was chosen to use as a case study. Substation Waalsprong is currently not congested, but adding extra renewable generation capacity will cause the station's capacity limits to be exceeded. Therefore, four additional generation scenarios were developed: a 9 MW-wind generator, a 12.85 MWp solar generator connected at 70% of its nominal capacity (resulting in 9 MW generation), a 12.85 MWp solar generator connected at 100% of its capacity and a combined 4.5 MW/4.5 MWp wind/solar generator.

Sub-question 2: What are the effects on the regional power grid of implementing a battery system at the system locations?
During the second phase of the research, different battery models were developed to see the impact of a battery system on the regional grid. The battery energy capacity necessary to solve all congestion at station Waalsprong for every additional generation scenario was found. The found capacities were quite large (26-54 MWh) compared to the additional generation,

and used inefficiently, for only a few cycles in the simulated year. Because of this, new battery models were developed, where part of the excess generation is curtailed, and part is stored in the battery. The battery + curtailment system was able to ensure the total load on station Waalsprong did not exceed the station's capacity limits during the simulated year, and the system succeeded in reducing curtailment volume and curtailment costs for the network operator significantly. A 10 MW/10 MWh battery + curtailment system resulted in a curtailment cost reduction between 65% and 80%, and a reduction in the volume of curtailed electricity of at least 60% for every system location at station Waalsprong. The largest relative reduction in curtailment costs and volume was achieved for the combined wind/solar generation scenario. Varying the connection location of the battery + curtailment system did not affect the curtailment costs or volume in any significant way.

Sub-question 3: What are the costs and benefits associated with implementing a battery system at the system locations, and how do these compare to other solutions for integrating additional renewables?

During this research phase, a cost-benefit analysis was performed, comparing different solutions to integrate the additional renewable generators at station Waalsprong. Overall, curtailing the excess generation was the option resulting in the least costs for the network operator. However, this might not be the most desirable solution, as it essentially wastes renewable electricity. Results from the CBA indicated that the large battery solving all congestion was always the most expensive solution for the network operator at Waalsprong. When comparing the results for the battery + curtailment system and grid upgrades at station Waalsprong, the additional generator determines which of the options is less costly: for both solar scenarios, the battery + curtailment system was the less expensive choice for the DSO, while for the wind and wind/solar scenario, the grid upgrade resulted in fewer costs. The location of the battery + curtailment system also influences the total costs of the solution: locating the battery + curtailment system at the generator results in lower costs for the network operator at station Waalsprong.

Sub-question 4: How does the institutional setting impact the value of a battery system for the Dutch regional power system?

The fourth phase of this thesis consisted of extensive research into regulations regarding battery systems in the Netherlands and interviews with relevant stakeholders. Two main elements influencing the value of battery systems for the Dutch regional power system were identified. First, network operators are currently not allowed to own and operate batteries in most cases, which is not likely to change in the (near) future. Therefore, network operators seeking to integrate battery systems or other forms of flexible capacity in their networks will have to request it from commercial parties. The second element connects to that: commercial parties operating battery systems are regarded both as generators and consumers, resulting in high connection and transportation tariffs. The current setup of transportation tariffs makes it highly unattractive for battery operators to locate anywhere else than in direct connection to a generator. The one case where network operators might be permitted to own and operate a battery system is during or while waiting for network upgrades. A considerable advantage for such a system is that it might be used for multiple locations consecutively.

9-0-2 Answer to the main research question

The main research question, formulated at the beginning of this thesis, was as follows:

How does the system location of a battery energy storage system for grid support influence the value such a system can provide to the regional Dutch power network in 2030?
Overall, there are two directions to base the answer to this question on. First, this thesis developed an understanding of the techno-economical answer by combining station Waalsprong case study results from the battery models with a cost-benefit analysis. These results indicate that at station Waalsprong, the location of the connection of a battery + curtailment system has some, but limited, impact on the value of the system for the network operator. In most generation scenarios, locating the battery + curtailment system at the generator resulted in fewer costs for the network operator than locating the system at the substation. The type of generator connected has a larger impact: for both solar-generation scenarios, a battery + curtailment system at station Waalsprong could provide more value to the network operator than simply upgrading the grid. For the pure wind and wind/solar scenarios, the curtailment volume can be reduced significantly by the system, but upgrading the grid results in fewer costs for the network operator at station Waalsprong.

When taking the institutional context into account as well, the advantage of locating a battery system at a generator becomes more pronounced: current regulations create a significant incentive to co-locate battery systems with generators, which is why in the near future, large-scale batteries in the Netherlands are most likely to be developed there. However, commercial developers are less inclined to consider local network conditions when selecting a location for their system, especially when operating their batteries on national markets. Thus, to ensure these batteries are valuable for local networks as well, new policies and systems will have to be developed.

9-1 Recommendations

This section will make recommendations based on the findings of this thesis. First, general recommendations regarding the context of battery systems and regional networks in the Netherlands will be described. Thereafter, recommendations for future research will be made.

9-1-1 General recommendations

This section will present five recommendations aimed at helping regional network operators cope with increased congestion in their networks and creating opportunities for battery operators to support network operators in this task.

The first and most crucial recommendation is aimed at the DSOs and the regulator. In the future, Dutch DSOs should strive to be more active in finding innovative solutions for the network capacity problems instead of choosing the standardised approach of upgrading the grid. This thesis has shown that for some situations, an innovative (battery) system could result in lower costs for the DSO and thus probably for Dutch society as a whole. It is crucial

that the regulator provides adequate frameworks to support innovative initiatives and pilot projects.

The second recommendation could be such a pilot project: DSOs should implement a regional tendering system for requesting flexible capacity from private parties (which could be a battery operator). For battery operators to regard this as a viable business model, it would be necessary to structure the market around long-term contracts for delivering flexibility. This would also decrease the risk for the DSO, as DSOs are not keen on relying on too many small parties for their network stability. A key element of this system is the availability of near-time congestion data for providers of flexibility to act upon. Findings from this research could be used in such a pilot: for station Waalsprong, additional renewable generation could be integrated at the station by using a combined battery and curtailment system. This system will likely yield the best results if the additional renewable generator is solar PV, and the battery system is connected directly to the generator.

The third recommendation is on the transportation tariffs for batteries. The regulator should investigate other options for charging battery operators for their network usage, as the current tariffs create an unlevel playing field for battery storage systems. For example, some countries have created exemptions from these tariffs for certain types of battery systems. Another solution could be to implement transportation tariffs based on currently available network capacity. By increasing tariffs during moments of low available network capacity, users are discouraged from transporting their power at those moments, and they are incentivised to increase transportation at moments with sufficient available network capacity and low transportation tariffs. Battery systems could enable network users to act on these variable tariffs.

The fourth recommendation was often raised by stakeholders in the regional electricity system: generate location-based connection tariffs for network users. If connection tariffs are increased at locations with little or no spare capacity to connect new elements and decreased at locations with more capacity, generators and (large-scale) consumers will be incentivised to consider local network conditions when choosing their operating location. In the case of battery systems, this will help DSOs manage the load FCR-operated batteries bring into their networks and encourage battery operators to find the network-optimal location for their battery system.

The fifth recommendation is based on pragmatism: for the DSOs, there might be too much network to upgrade in too little time. Getting the power networks ready for an electricity system based on solar and wind is a massive infrastructural project, and these types of projects tend to be time- and resource-consuming. In addition, industry experts expect shortages in materials and skilled personnel, which will cause even more delays. At the same time, renewable generation is being installed at a much higher pace. To keep up with increased generation, DSOs could look to battery systems to use on a temporary basis. These systems could provide extra capacity to congested areas in the grid while waiting for upgrades or ensure a stable connection while an upgrade is taking place.

9-1-2 Recommendations for future research

This section will discuss recommendations for future research. These recommendations are divided into two parts: the first part consists of recommendations for future research directly connected to the work presented in this thesis. The second part consists of future research directions based on the general recommendations made in the previous section.

Building from the work conducted during this thesis project, three directions would be valuable to investigate further. First of all, to reinforce the findings from this thesis, it would be beneficial to extend the method presented to a larger number of (sub)stations in the Dutch MV grid. By doing so, an overview can be created of the characteristics of (sub)stations where adding a battery system could be valuable for the network operator. These characteristics could be valuable for DSOs when making the trade-off between grid upgrades or other solutions during congestion. An essential part of this exercise would be to include (sub)stations where grid upgrades are challenging and therefore more expensive.

Secondly, the effects of varying weather years on the outcomes should be studied to ensure the developed insights are robust for years of extreme wind or solar generation or longer cold periods. Years with colder winters could show an increase in electricity consumption due to the higher demand from heat pumps, combined with reduced renewable electricity generation.

Thirdly, several stakeholders indicated the growing tension created by batteries that operate on national markets but are connected to regional networks. Therefore, it would be valuable to study the correlation of local network conditions and the various national markets batteries can be active on. Such a study could develop more insights into the interplay between the national market prices and regional conditions, support regional network operators in planning their future systems and aligning with battery operators on the most optimal connection points for their systems.

For implementing the general recommendations made in the previous section, numerous studies could be beneficial. Firstly, the design of a regional tendering system for flexible capacity should be studied: at which price level will commercial parties provide flexible capacity, and is that price level feasible for DSOs? Additionally, the network impact of such a system should be studied to determine the effects flexibility contracts have on both regional and national power networks.

Another valuable research direction would be to develop the discussed new systems for transportation and connection tariffs and to study the effects of the developed tariff systems on regional network situations. Studies along these lines have been conducted, but the role of battery systems in previous studies has been small. With prices for battery systems declining rapidly, it is imaginable battery systems will play a larger role in market players reacting to flexible transportation and connection tariffs than previously assumed.

9-2 Reflection

This section will reflect upon the relevance of this thesis, from three different perspectives. It will first discuss the academic relevance of the research and findings. After that, both the practical and societal relevance of the research will be considered. Finally, a personal reflection on the research and research process is included.

9-2-1 Academic relevance

This thesis researches how and where battery systems could be used to integrate additional renewable generation capacity into regional networks in the Netherlands that are already operating close to their capacity limits. Traditionally, the way to integrate additional loads into existing power networks was always to upgrade these networks, which is often costly. Various studies have been conducted into the possibility of using battery systems instead of upgrading the network, and the findings of this research confirm the findings of (Idlbi et al., 2016) and (Mateo et al., 2016) and (Spiliotis et al., 2016), which state that in some situations, using a battery system will lead to lower costs for the DSO than upgrading the network. This study also finds that curtailment is often the least-costs solution for integrating additional renewables, which is in agreement with findings by (Idlbi et al., 2016) and (Segundo Sevilla et al., 2018).

This thesis builds upon existing literature by introducing a case study of a MV distribution station in the Netherlands that is at risk for congestion in the future. A unique and valuable element of this study is the use of real historical load data provided by the DSO. For several previous studies, actual load data was unavailable (Purvins & Sumner, 2013), (Spiliotis et al., 2016). Therefore, loads were simulated, possibly leading to an inaccurate reflection of the network situation.

Furthermore, this thesis introduced the concept of 'system location': the combination of the battery system's network connection point and the renewable generator it was used with. Previous work has often considered either the influence of the network connection point ((Grover-Silva et al., 2018), (Faessler et al., 2016), (Karanki & Xu, 2017)), or the influence of the connected renewable generator ((Denholm et al., 2016), (Mallapragada et al., 2020). Studies combining these two elements do not seem frequent.

Lastly, a method was developed to determine the most economical solution from grid upgrades, curtailment, and a battery + curtailment system for integrating additional renewable generation into a specific distribution station in the Netherlands. This method could be applied to other stations, as described in the recommendations for future research. However, because the focus of this thesis has been on regional networks in the Netherlands, the findings are not necessarily applicable on a global scale, possibly limiting the relevance for the wider scientific community.

9-2-2 Practical & societal relevance

The energy transition is finally starting to take off in the Netherlands: in 2014, only 5.5% of our consumed electricity was generated from solar and wind, while in 2020, the number

was already at 18.4% (Centraal Bureau voor Statistiek, 2020). In the past years, the adequacy of our electricity networks has become an area of concern, as the TSO and DSOs have raised alarms about the status of their networks. Additionally, generators have found that in increasingly large shares of the Netherlands, it takes a long time to realise a new connection.

The topic of this thesis is connected to these larger issues in the Dutch power system, and therefore highly relevant for society at the moment. If we want to reach our emission reduction goals, solutions must be found to integrate additional renewable generation into the power networks.

In a practical sense, the case study of station Waalsprong has provided insights that might be relevant for Liander, the DSO in that area. The study has shown that in some scenarios, a battery + curtailment system could be more cost-effective than grid upgrades at station Waalsprong. It depends on the developments of additional renewable generation at the station which pathway is cost-optimal.

In addition to that, the case study has proven (again) that network operators and policymakers should pay close attention to technological alternatives to grid upgrades, as they might be less costly or time-consuming. Furthermore, this thesis has made recommendations regarding the implementation of battery systems and the reduction of congestion in the Netherlands, based on an analysis of the broader context of battery systems in the Netherlands.

9-2-3 Personal reflection

This thesis marks the end of my time at the Delft University of Technology and concludes my Msc. in Sustainable Energy Technology. The research conducted for this thesis has been challenging at times, but it has also provided me with a lot of new knowledge of energy systems, Dutch power networks and batteries. Just as the SET program is set up to cover a broad range of topics related to the energy transition, this thesis looked at battery systems using different methods, which created an interesting variation in the activities carried out. Starting this project, I had almost no knowledge of batteries, and I did not think they would play a large role in our future power systems. Now, I know better: I believe batteries will be an essential element of future power systems, and it has been an excellent opportunity to learn about them during my thesis.

Appendix A

Substation Waalsprong - Profiles

This section contains the original 10 MW wind profile for station Waalsprong and all generated profiles.

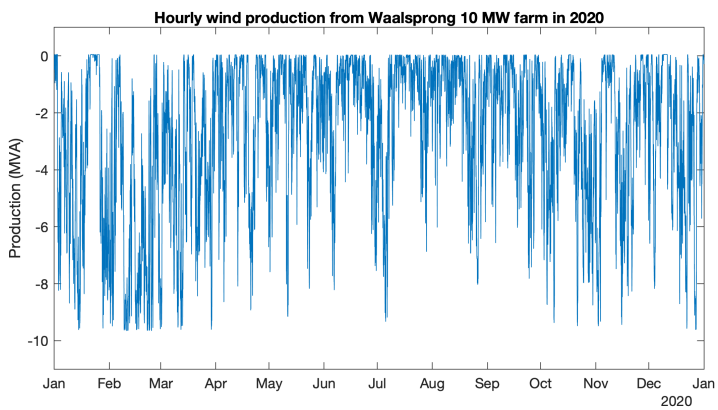


Figure A-1: 2020 production in MVA from the 10 MW wind farm connected to station Waalsprong. Created with data from (Liander, 2021c).

A-1 Generated production profiles

This section contains additional plots of the wind, solar and combined wind/solar production profiles generated for station Waalsprong.

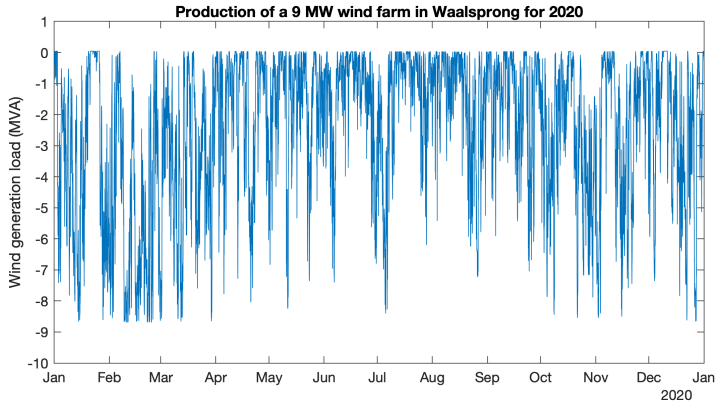


Figure A-2: Generated annual wind production profile for a 9 MW wind farm in Waalsprong in 2020. Generated with data from (Liander, 2021c).

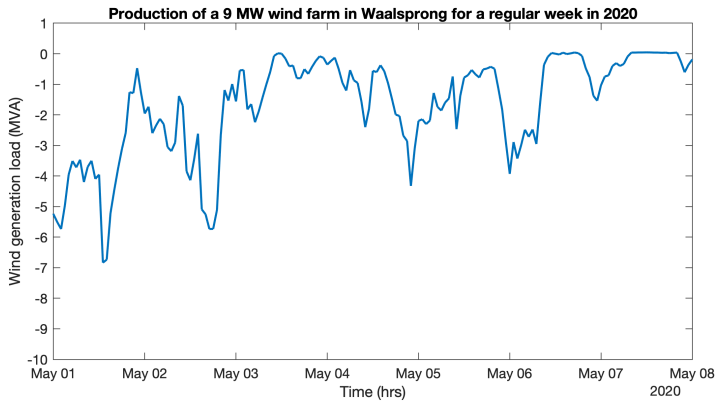


Figure A-3: Generated wind production profile for a 9 MW wind farm in Waalsprong for a representative week in 2020. Generated with data from (Liander, 2021c).

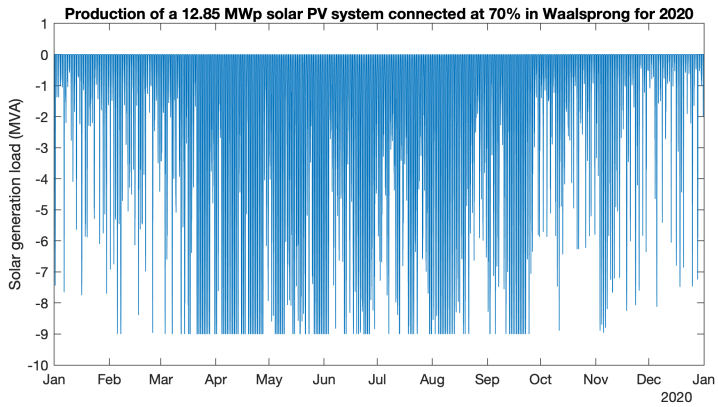


Figure A-4: Generated annual solar PV production profile for a 12.85 MWp solar generator connected at 70% in Waalsprong in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

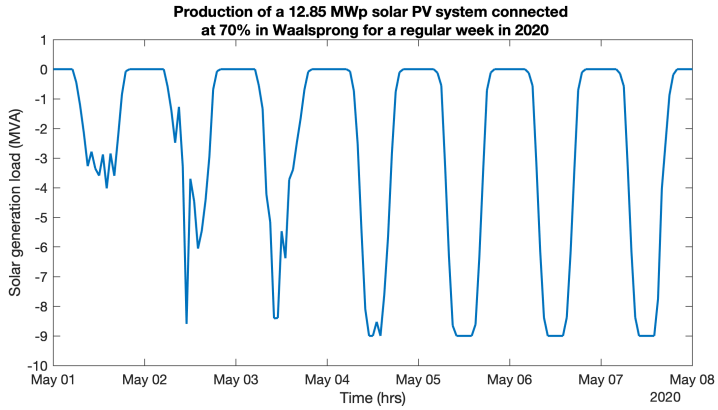


Figure A-5: Generated solar PV production profile for a 12.85 MWp solar generator connected at 70% in Waalsprong for a representative week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

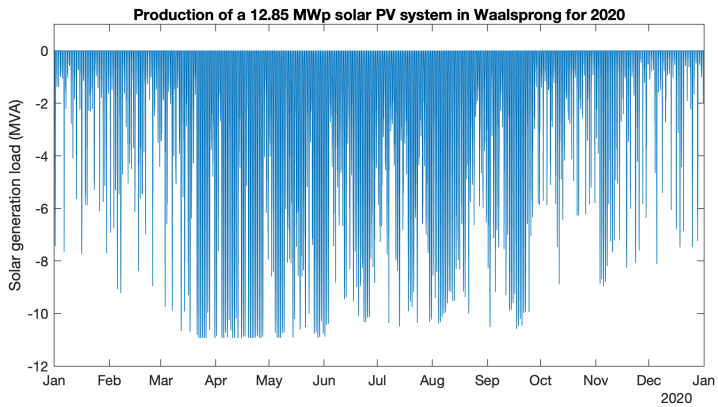


Figure A-6: Generated annual solar PV production profile for a 12.85 MWp solar generator in Waalsprong in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

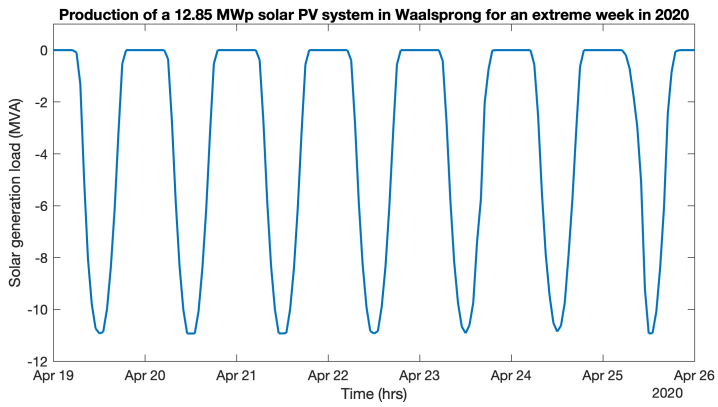


Figure A-7: Generated solar PV production profile for a 12.85 MWp solar generator in Waalsprong for an extreme week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

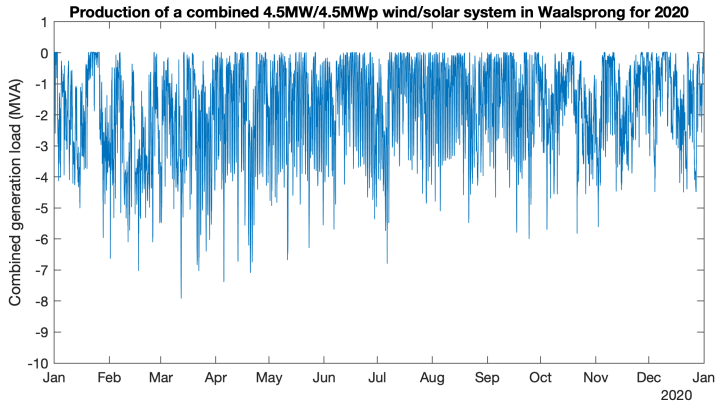


Figure A-8: Generated production profile for a combined 4.5MW/4.5MWp wind/solar generator in Waalsprong in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

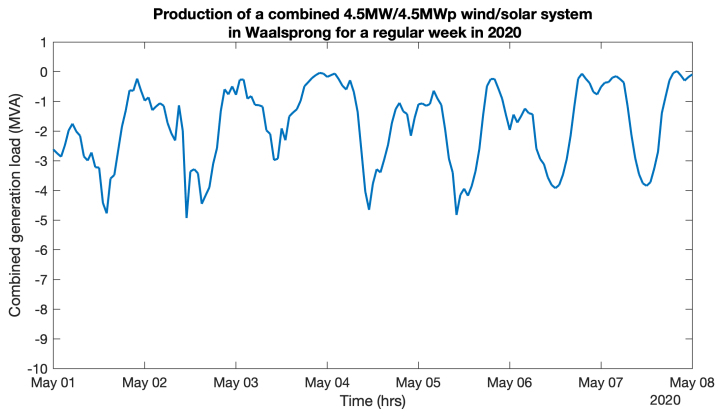


Figure A-9: Generated production profile for a combined 4.5MW/4.5MWp wind/solar generator in Waalsprong for a representative week in 2020. Generated with data from (Solcast, 2021) and (PVSyst SA, 2021).

A-2 Overshoot-duration curve

This section contains the overshoot-duration curves for station Waalsprong with additional wind, solar connected at 70%, solar connected at 100% or combined wind/solar generation for 2030. The values plotted are the values by which the station's transport capacity limit is exceeded, for the number of hours on the horizontal axis. It is clear from the figure that integrating the additional 9 MW wind at Waalsprong leads to the highest number of hours with excess loads, and the combined wind/solar to the lowest number of hours with excess loads.

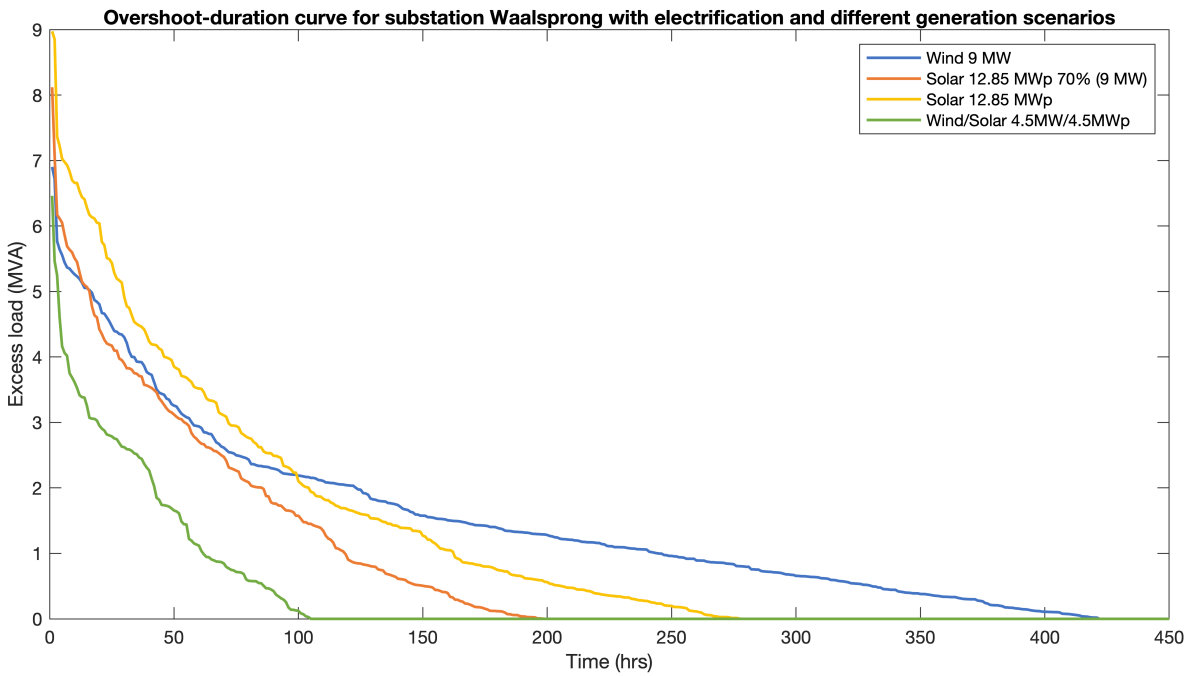
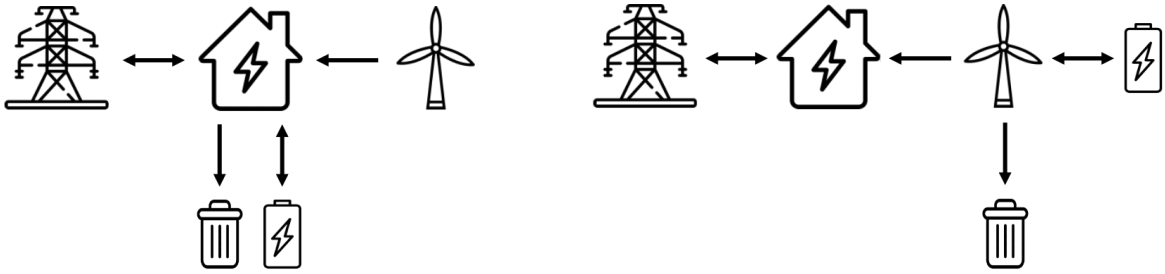


Figure A-10: Overshoot-duration curve plotting the absolute excess load on station Waalsprong in 2030 for the different additional renewable generation scenarios.

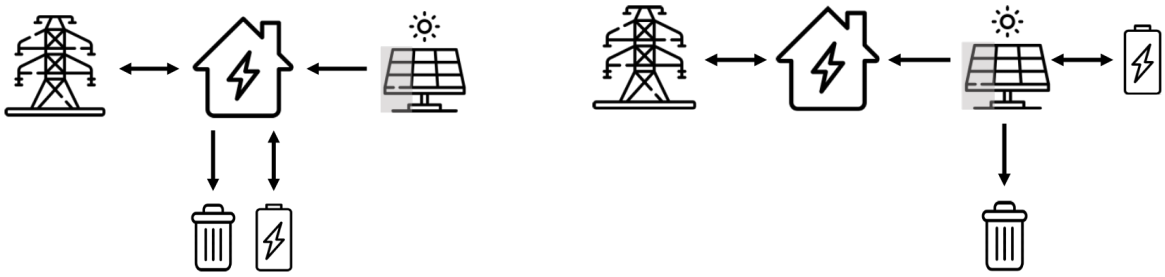
A-3 Scenario overview

This section contains a graphic overview of all scenarios modelled for the Waalsprong case study, in figures A-11a to A-14b. The battery system locations correspond to the scenarios summarised in table 5-8.



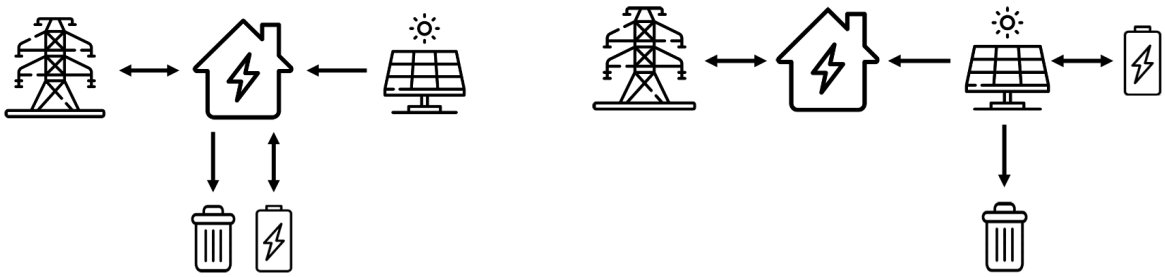
(a) Battery connected at generator **(b)** Battery connected at station

Figure A-11: Scenarios with additional 9 MW wind generation connected to the substation.



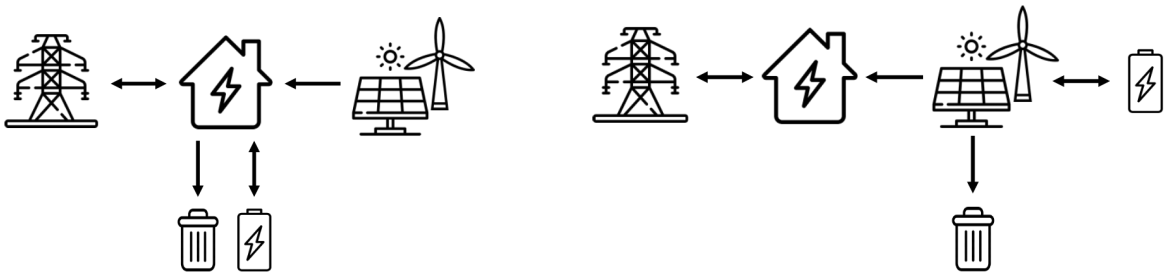
(a) Battery connected at generator **(b)** Battery connected at station

Figure A-12: Scenarios with additional 12.85 MWp solar generation connected to the substation at 70% of its peak capacity, resulting in 9 MW capacity added.



(a) Battery connected at generator **(b)** Battery connected at station

Figure A-13: Scenarios with additional 12.85 MWp solar generation connected to the substation at 100% of its peak capacity.



(a) Battery connected at generator **(b)** Battery connected at station

Figure A-14: Scenarios with additional combined 4.5 MW/4.5 MWp wind/solar generation connected to the substation.

A-4 Model validation

To determine whether both MATLAB models behave according to the optimisation objectives and constraints, they were tested using a week of extreme load on the station.

For validating the battery at the substation model, the battery capacity was set at 10 MWh/10 MW, the 9 MW wind farm was connected to the system, and 2020 EPEX prices were used. The resulting plot is included in figure A-15 below. Three elements from these results point to the correct functioning of the model at the substation:

1. The new load on the station does not exceed the station limit of -10.5 MVA.
2. At moments where the original load did exceed the station limit, the battery or curtailment are used to prevent this.
3. The battery SoC stays between the predefined charging limits.

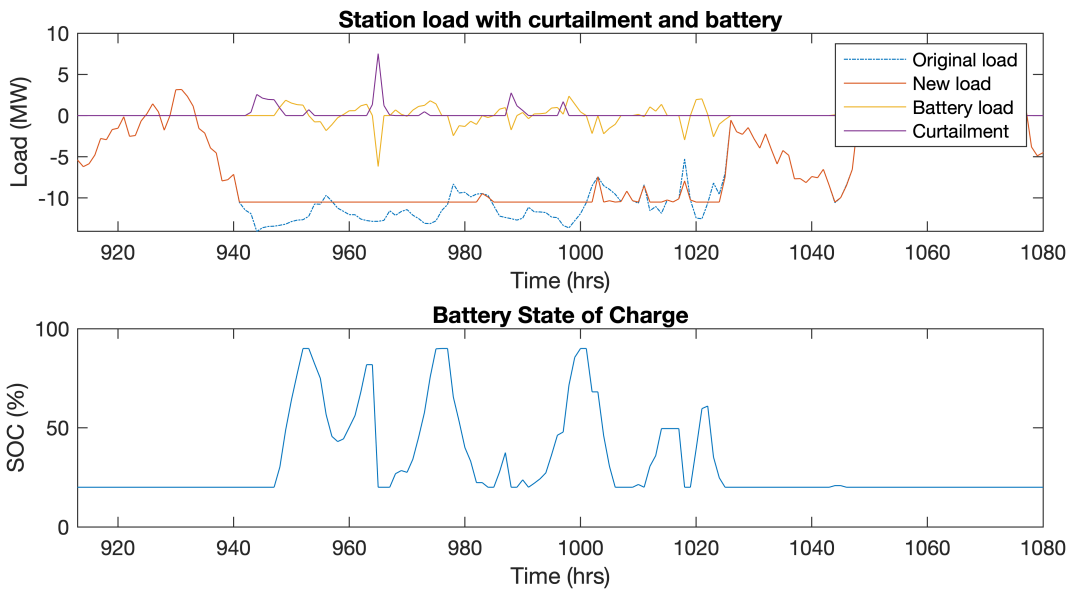


Figure A-15: Upper plot: plot of the station load, battery load and curtailment for a week of extreme wind production in February. Lower plot: plot of the battery SoC for the same week. For both plots, the battery is connected to the station.

Furthermore, the model achieved its goal: the curtailment costs for the network operator were significantly reduced. The original curtailment costs during this week were €14,486, and the new curtailment costs were €5,759.

For validating the battery at the generator model, the battery capacity was set at 10 MWh/10 MW, the 12.85 MWp Solar PV plant was connected to the system and 2020 EPEX prices were used. The 12.85 MWp Solar PV plant was connected at 70% of its peak capacity. The resulting plot is included in figure A-16. From this plot, it is clear that battery operation is heavily influenced by the diurnal cycle of the solar PV plant. All validating elements described in the previous section also hold true for this model. Furthermore, curtailment

costs were again reduced significantly. The original curtailment costs were €12,183 and the new curtailment costs were €5,958.

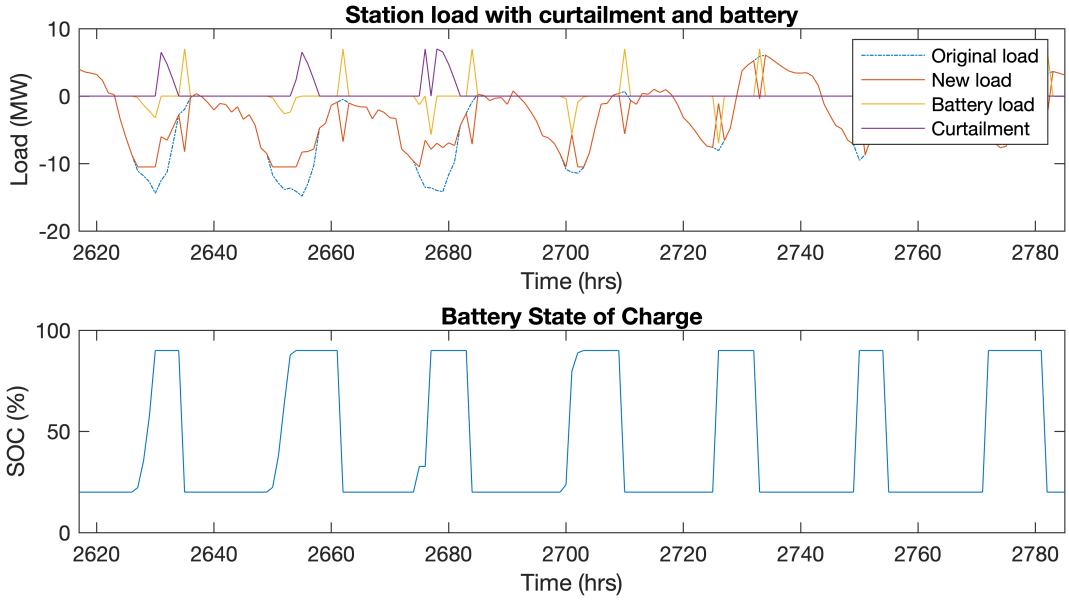


Figure A-16: Upper plot: plot of the station load, battery load and curtailment for a week of extreme solar production in April. Lower plot: plot of the battery SoC for the same week. For both plots, the battery is connected to the solar generator.

A-5 Battery system parameters

In table A-1, the parameters used for modelling the battery system have been included. All parameters were taken from the IRENA costs-of-service tool, which contains projections for LFP battery systems in 2030 (IRENA, 2017a).

Table A-1: Battery parameters used for the battery dispatch models and the cost-benefit analyses. Values from (IRENA, 2017a).

Battery system parameter	Value	Unit
Cycle life	4774.3	Equivalent full cycles
Calendar life	18.4	Years
Max. SoC	95	%
Min. SoC	5	%
Initial SoC	50	%
Capacity fade limit	20	% of original capacity
Energy capacity costs	183.8	€ per kWh
Power conversion capacity costs	41.5	€ per kWh
OPEX storage system	1.5	% of investment per year
OPEX power conversion system	1.5	% of investment per year

A-6 Battery model results station Waalsprong

In this section, additional results from the modelling of the battery systems at station Waalsprong are included. Figure A-17 shows the energy curtailed relative to the electricity generated by the additional renewable generator considered for every scenario at station Waalsprong. Figure A-18 shows the number of full battery cycles during the simulation year for every scenario at station Waalsprong. More information on these results has been included in section 5-7.

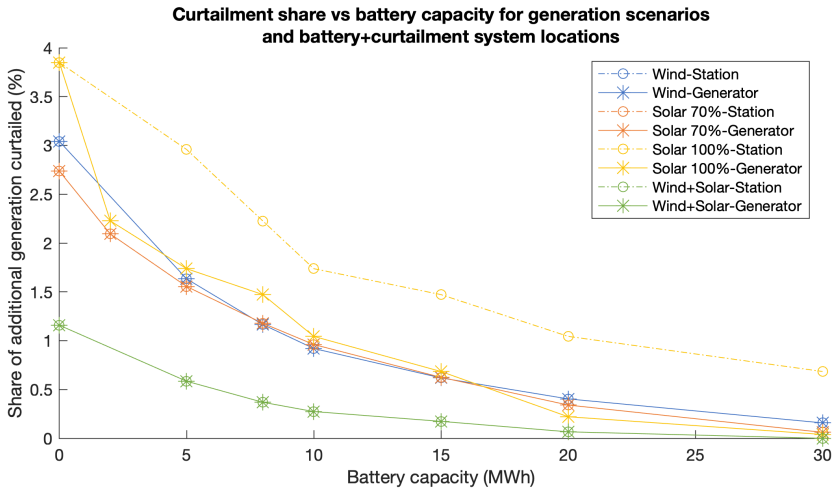


Figure A-17: Plot of the energy curtailed relative to the electricity generated by the additional renewable source for the different generator scenarios and locations of the battery + curtailment system at station Waalsprong.

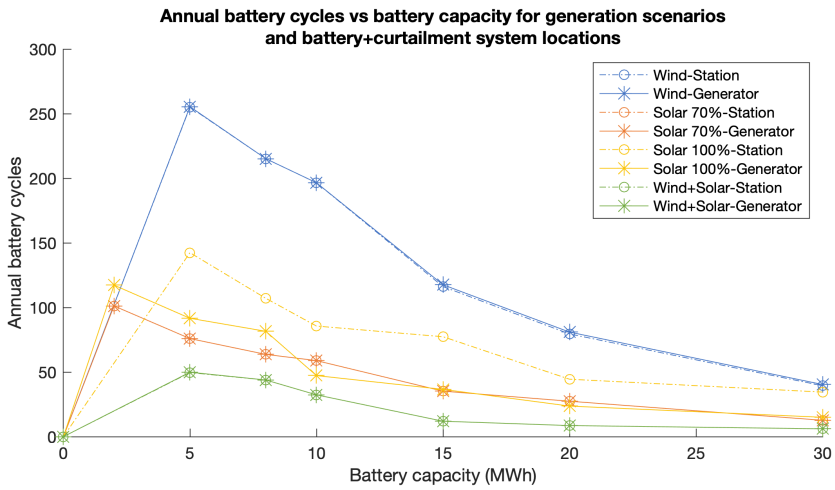


Figure A-18: Plot of the number of full battery cycles occurring during the year for the different generator scenarios and locations of the battery + curtailment system at station Waalsprong.

Appendix B

CBA cash flow diagrams

This section contains the detailed cash flow figures constructed during the cost-benefit analyses. Figures B-1 to B-20 depict both the discounted annual cash flow on the left vertical axis and the total NPV of the project on the right vertical axis.

Curtailment

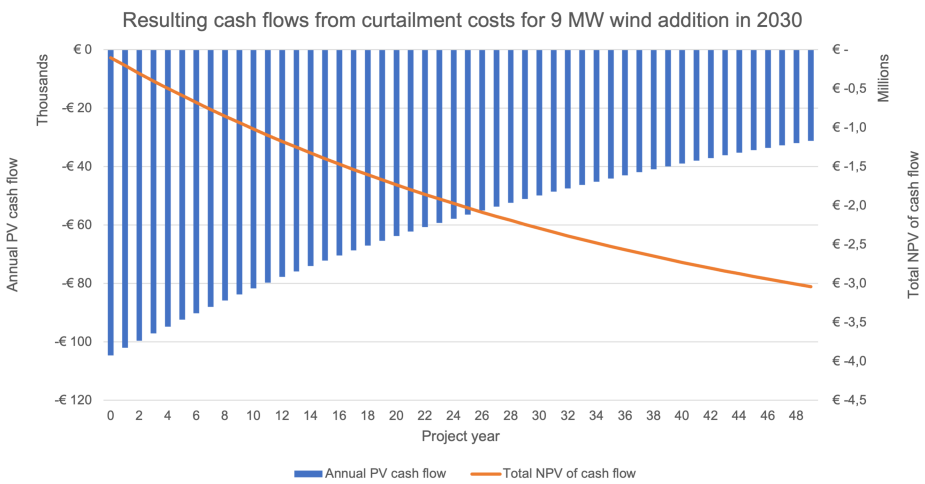


Figure B-1: Diagram of the costs associated with curtailment to integrate an additional 9 MW of wind generation at station Waalsprong in 2030 without congestion.

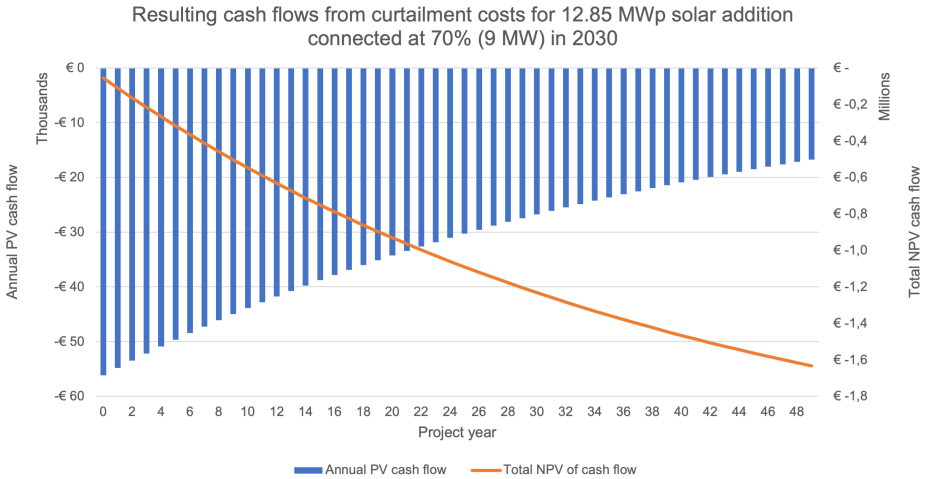


Figure B-2: Diagram of the costs associated with curtailment to integrate an additional 12.85 MWp of solar PV generation, connected at 70% at station Waalsprong in 2030 without congestion.

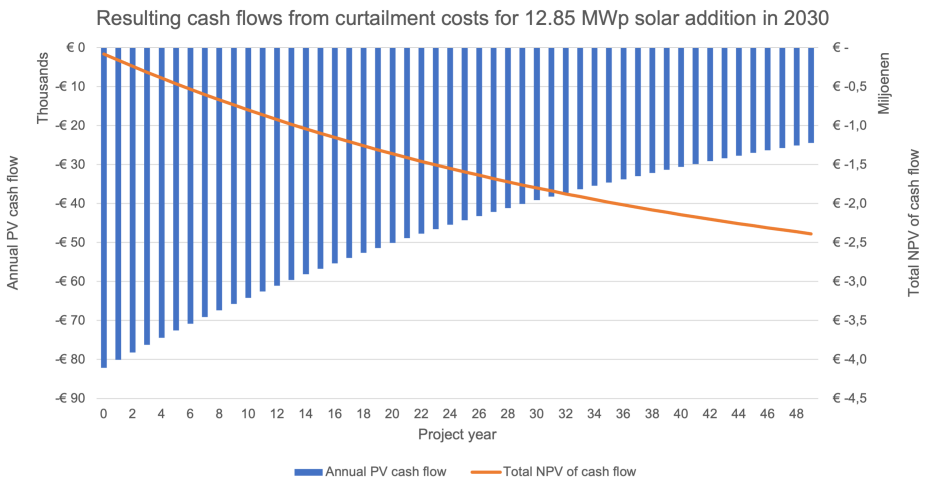


Figure B-3: Diagram of the costs associated with curtailment to integrate an additional 12.85 MWp of solar PV generation at station Waalsprong in 2030 without congestion.

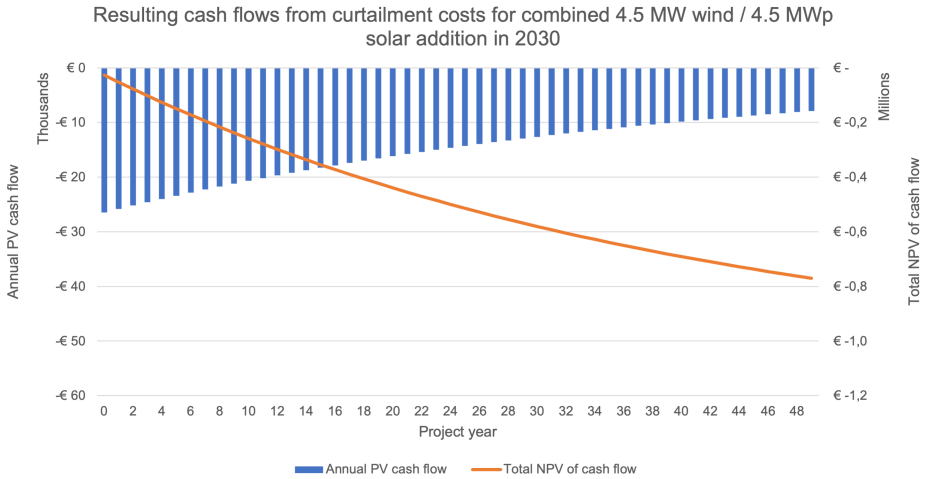


Figure B-4: Diagram of the costs associated with curtailment to integrate an additional 4.5 MW/4.5 MWp combined wind/solar generation at station Waalsprong in 2030 without congestion.

Grid upgrade

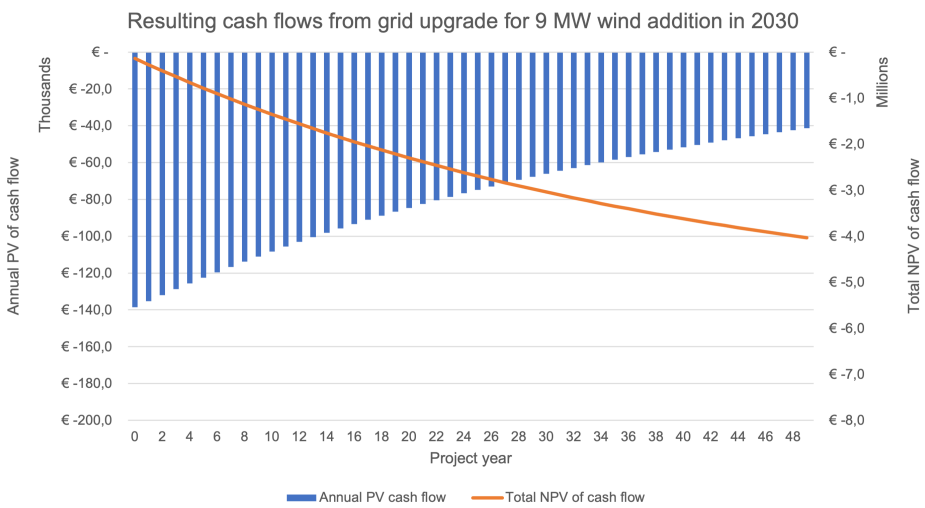


Figure B-5: Diagram of the costs associated with grid upgrades to integrate an additional 9 MW of wind generation at station Waalsprong in 2030 without congestion.

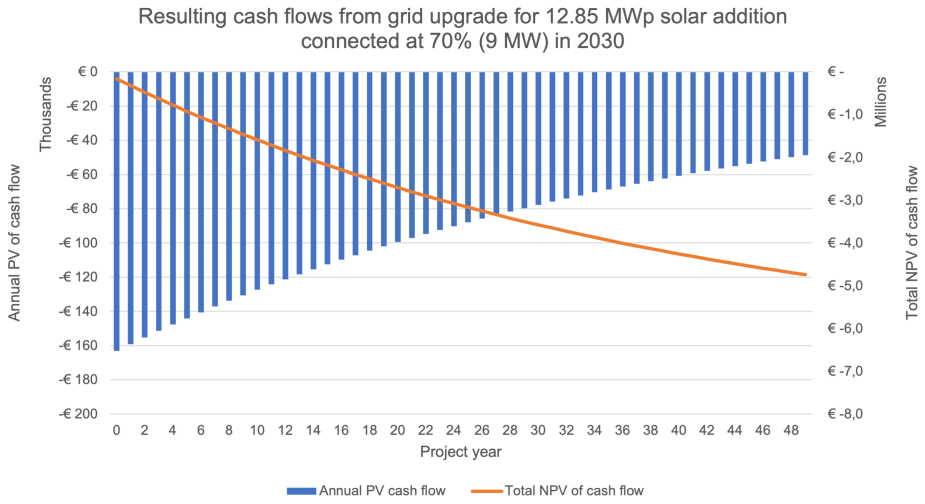


Figure B-6: Diagram of the costs associated with grid upgrades to integrate an additional 12.85 MWp of solar generation connected at 70% at station Waalsprong in 2030 without congestion.

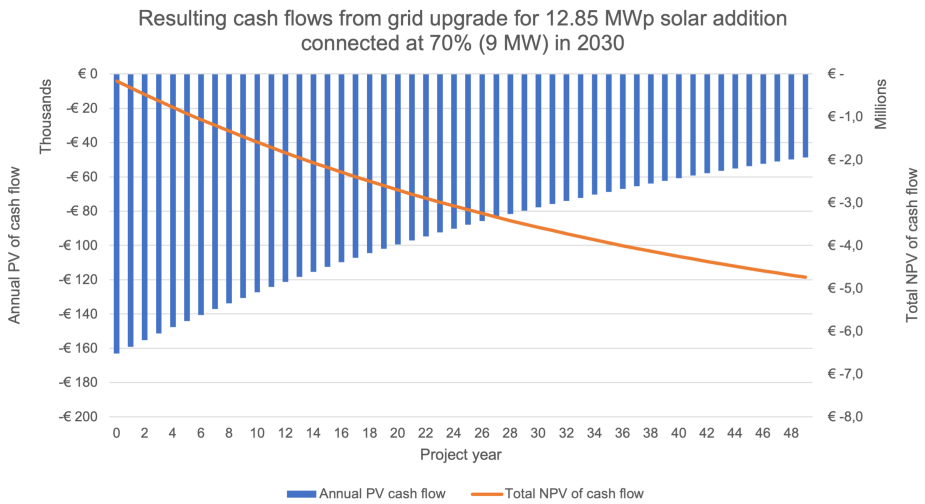


Figure B-7: Diagram of the costs associated with grid upgrades to integrate an additional 12.85 MWp of solar generation at station Waalsprong in 2030 without congestion.

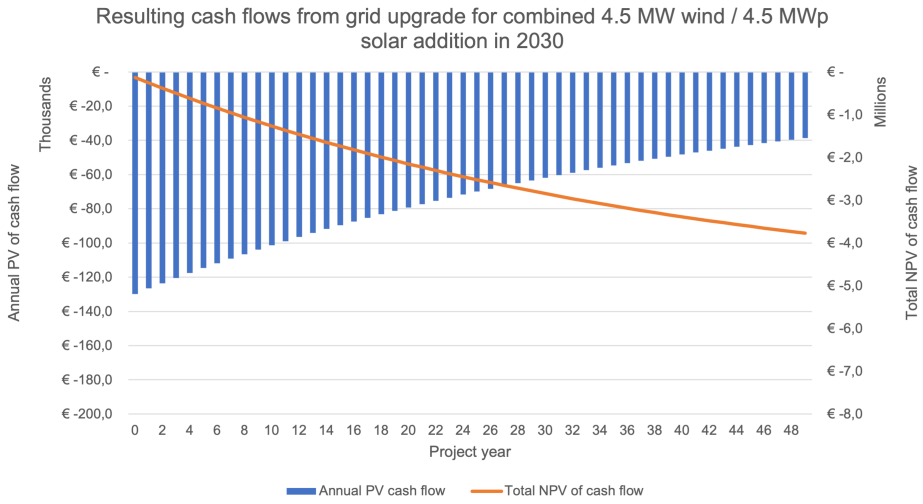


Figure B-8: Diagram of the costs associated with grid upgrades to integrate an additional combined 4.5 MW/4.5 MWp wind/solar generation at station Waalsprong in 2030 without congestion.

Large battery solving all congestion

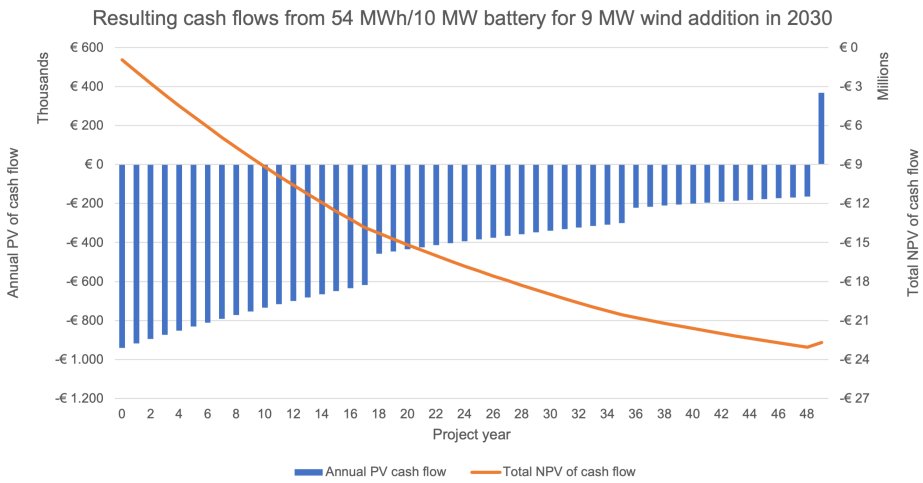


Figure B-9: Diagram of the costs and benefits associated with a 2035 MWh/10 MW battery system at station Waalsprong to integrate an additional 9 MW of wind generation without congestion in 2030.

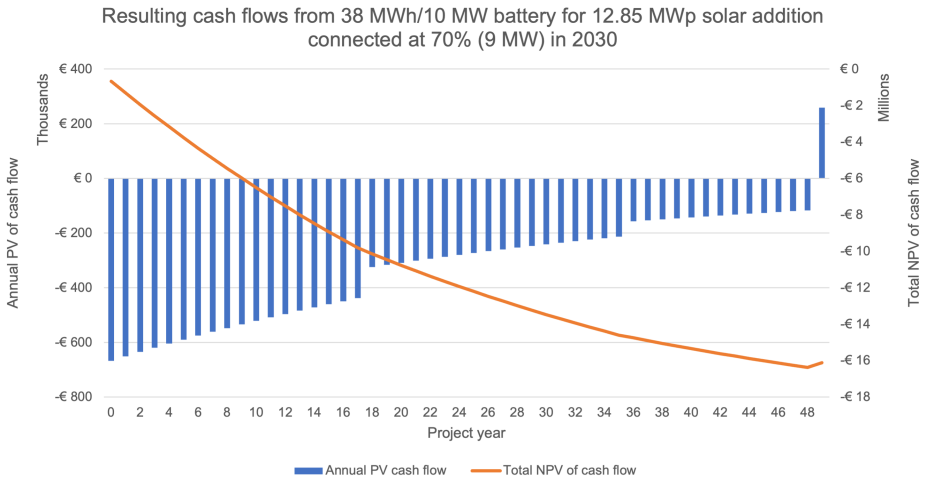


Figure B-10: Diagram of the costs and benefits associated with a 310 MWh/10 MW battery system at station Waalsprong to integrate an additional 12.85 MWp of solar generation connected at 70% without congestion in 2030.

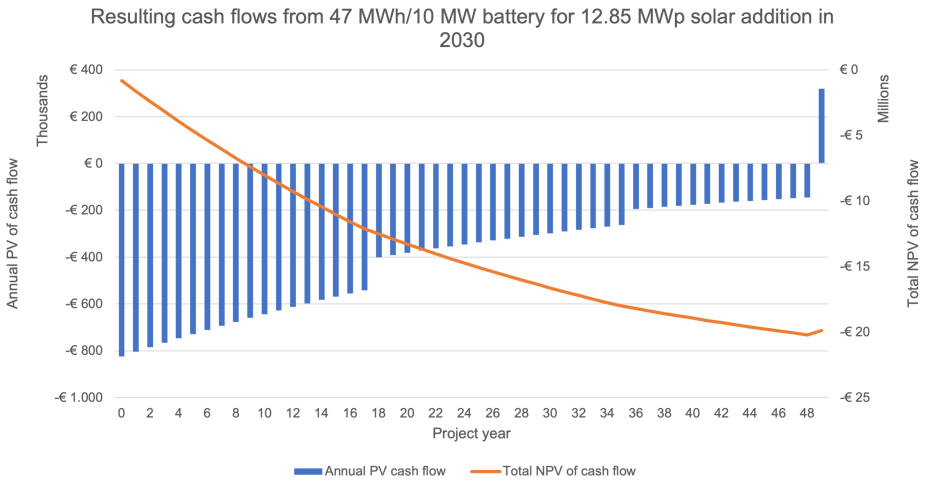


Figure B-11: Diagram of the costs and benefits associated with a 335 MWh/10 MW battery system at station Waalsprong to integrate an additional 12.85 MWp of solar generation without congestion in 2030.

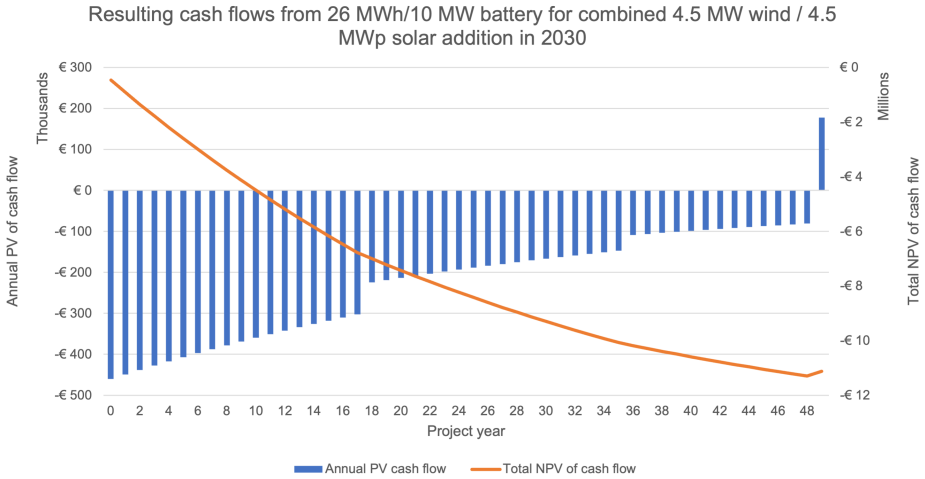


Figure B-12: Diagram of the costs and benefits associated with a 285 MWh/10 MW battery system at station Waalsprong to integrate an additional 4.5 MW/ 4.5 MWp wind/solar combined generation without congestion in 2030.

Battery + Curtailment system located at the station

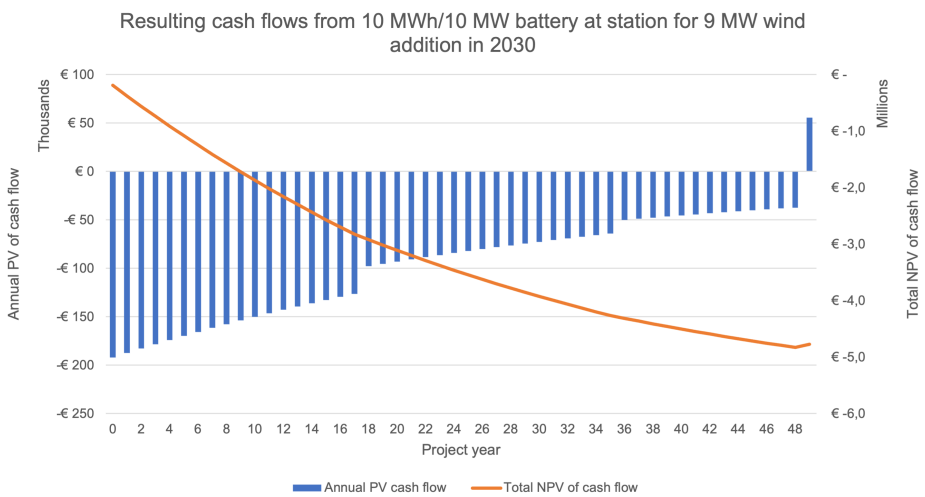


Figure B-13: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at station Waalsprong to integrate an additional 9 MW of wind generation without congestion in 2030.

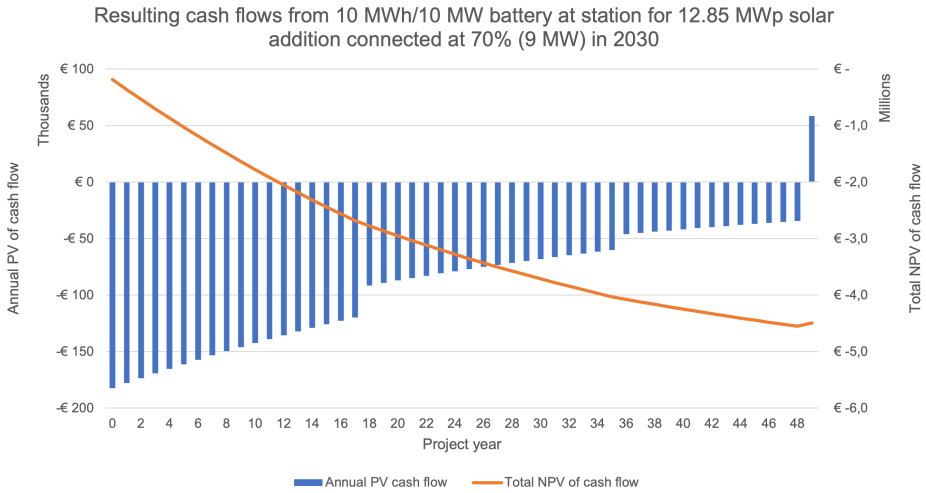


Figure B-14: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at station Waalsprong to integrate an additional 12.85 MWp of solar generation connected at 70% without congestion in 2030.

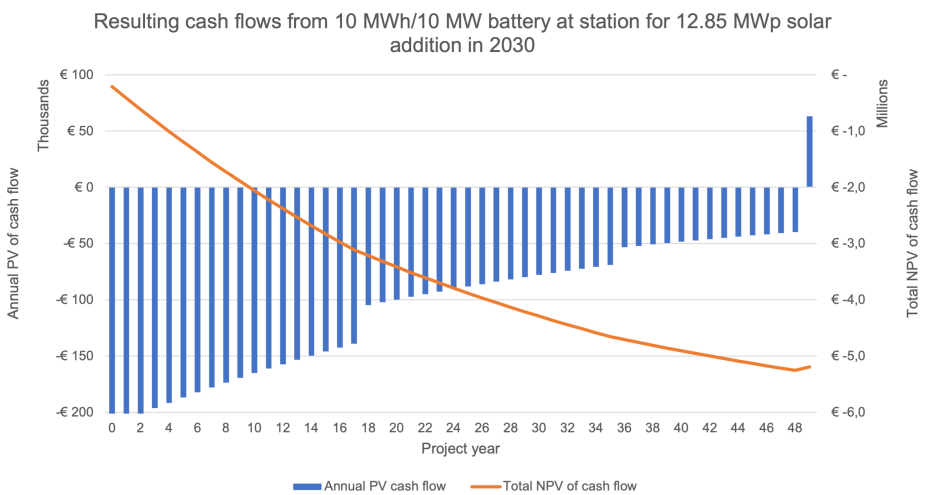


Figure B-15: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at station Waalsprong to integrate an additional 12.85 MWp of solar generation without congestion in 2030.

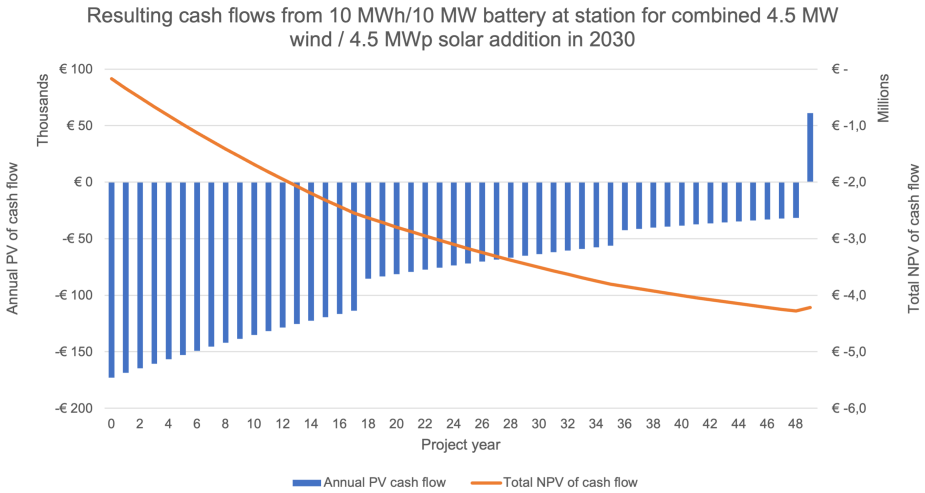


Figure B-16: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at station Waalsprong to integrate an additional 4.5 MW/4.5 MWp combined wind/solar generation without congestion in 2030.

Battery + Curtailment system located at the generator

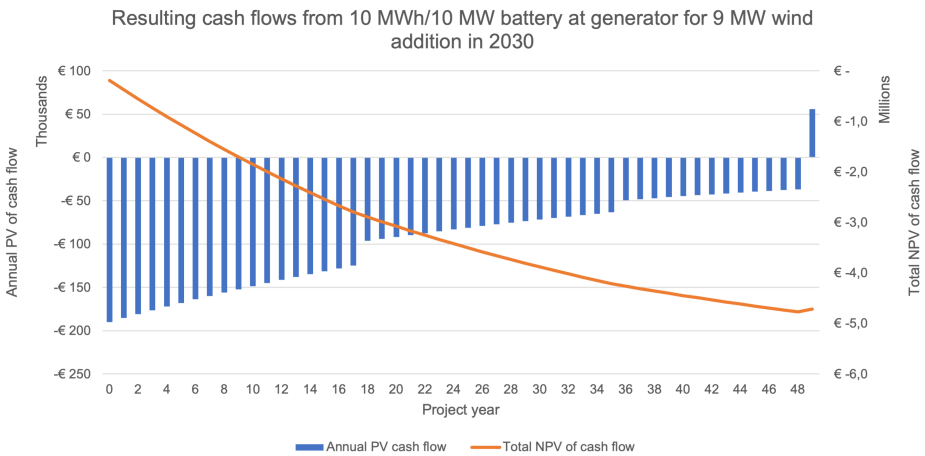


Figure B-17: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at the generator to integrate an additional 9 MW of wind generation at station Waalsprong without congestion in 2030.

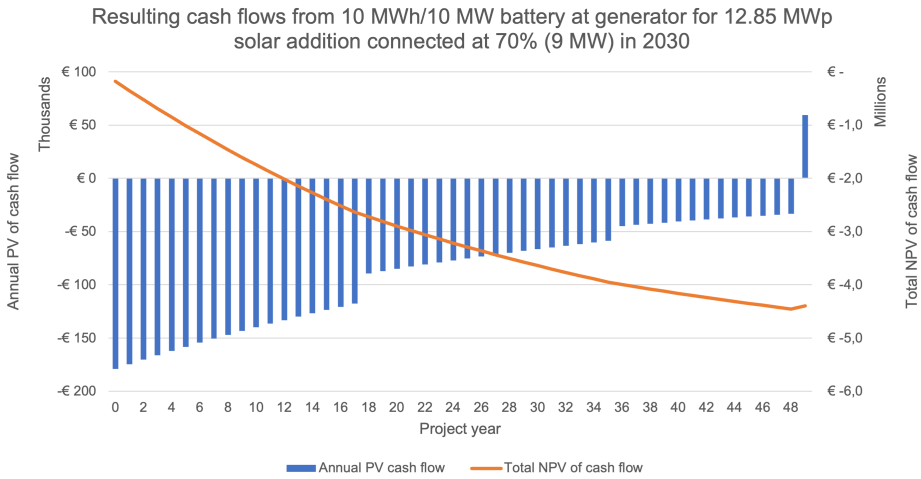


Figure B-18: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at the generator to integrate an additional 12.85 MWp of solar generation connected at 70% at station Waalsprong without congestion in 2030.

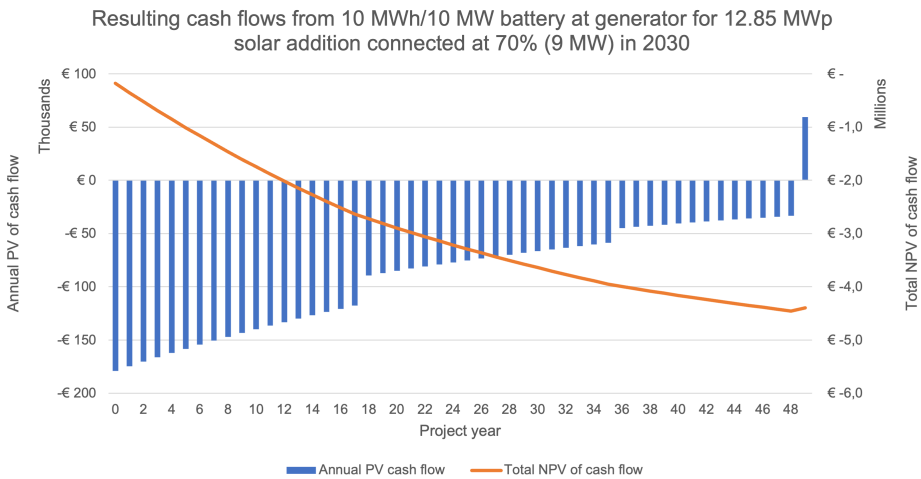


Figure B-19: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at the generator to integrate an additional 12.85 MWp of solar generation at station Waalsprong without congestion in 2030.

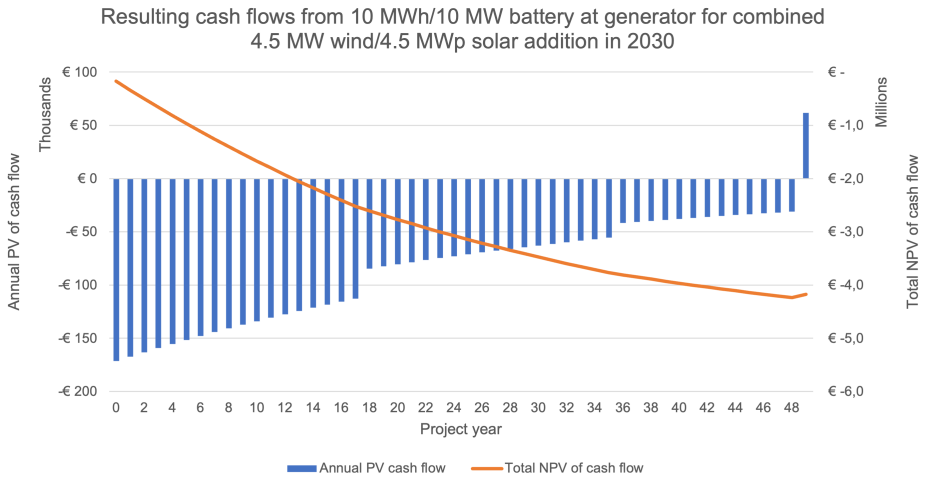


Figure B-20: Diagram of the costs and benefits associated with a combined system of curtailment and a 10 MWh/10 MW battery connected at the generator to integrate an additional 4.5 MW/4.5 MWp combined wind/solar generation at station Waalsprong without congestion in 2030.

Appendix C

CBA sensitivity analysis

Because several parameters of the cost-benefit analysis performed in chapter 6 are estimations of future values and prices, this appendix will evaluate the sensitivity of the CBA results to four key parameters. The parameters included are:

1. The costs of curtailment for the DSO
2. The costs of the battery system
3. The learning rate (cost reduction over time) of the battery system
4. The costs of grid upgrades

C-0-1 Sensitivity analysis: curtailment costs

There was some disagreement between the different DSOs over the costs of curtailment, and estimates ranged from zero remuneration for producers to €600 + EPEX per MWh. Therefore, this sensitivity analysis will evaluate two scenarios that are likely within the feasible range: doubling the costs for subsidies + guarantees of origin, and removing the costs for subsidies altogether, resulting in only costs for the guarantees of origin. The latter scenario can provide an outlook to a future point in the energy transition, where there might not be (SDE) subsidies available for renewable generators.

First, the scenario with double the curtailment costs, from €125 + EPEX to €250 + EPEX per MWh, was evaluated. Tables C-1 and C-2 contain the outcomes of the MATLAB runs with increased curtailment costs. Compared to the original results, the battery goes through more cycles at both locations, decreasing curtailment volume. However, even with more battery usage, the curtailment costs are significantly higher than in the original model outcomes for all scenarios.

When comparing the four solutions in figure C-1, the effect of doubling the curtailment costs is clearly visible: for all scenarios, the NPV of curtailment by the DSO has approximately

doubled. Just as for the original curtailment costs case, integrating the wind or wind/solar generator is less expensive using grid upgrades than using the battery + curtailment system. The costs difference between the solutions has increased. Integrating the two different solar generators using grid upgrades is approximately at the same cost level as using the battery + curtailment system located at the generator.

Overall, increased curtailment costs bring grid upgrades to a comparable (or less expensive) cost level as the battery + curtailment solutions for both locations. That makes sense: once curtailment becomes more expensive, it is more attractive to upgrade the grid. The wind scenario emphasises this: doubling the curtailment costs has caused the curtailment solution to become the most expensive solution, while it was the least expensive one at the original curtailment costs.

Table C-1: Overview of model output values for station Waalsprong at curtailment costs of €250/MWh + EPEX prices, with the battery and curtailment system located at the **substation**.

	Curt. volume w/o bat. (MWh)	Curt. volume w. bat. (MWh)	Curt. costs w/o bat. (k€)	Curt. costs w. bat. (k€)	Bat. operating profit (k€)	Cycles
Wind 9 MW	658	167	187	43	7.8	248
Solar 9 MW (12.85 MWp at 70%)	392	118	105	30	7.2	90
Solar 12.85 MWp	566	190	153	50	11	118
Wind/Solar 4.5/4.5 MW	185	33	50	8	5	49

Table C-2: Overview of model output values for station Waalsprong at curtailment costs of €250/MWh + EPEX prices, with the battery and curtailment system located at the **generator**.

	Curt. volume w/o bat. (MWh)	Curt. volume w. bat. (MWh)	Curt. costs w/o bat. (k€)	Curt. costs w. bat. (k€)	Bat. operating profit (k€)	Cycles
Wind 9 MW	658	166	187	43	10	247
Solar 9 MW (12.85 MWp at 70%)	392	118	105	30	12	90
Solar 12.85 MWp	566	191	153	50	18	123
Wind/Solar 4.5/4.5 MW	185	33	50	8	7	49

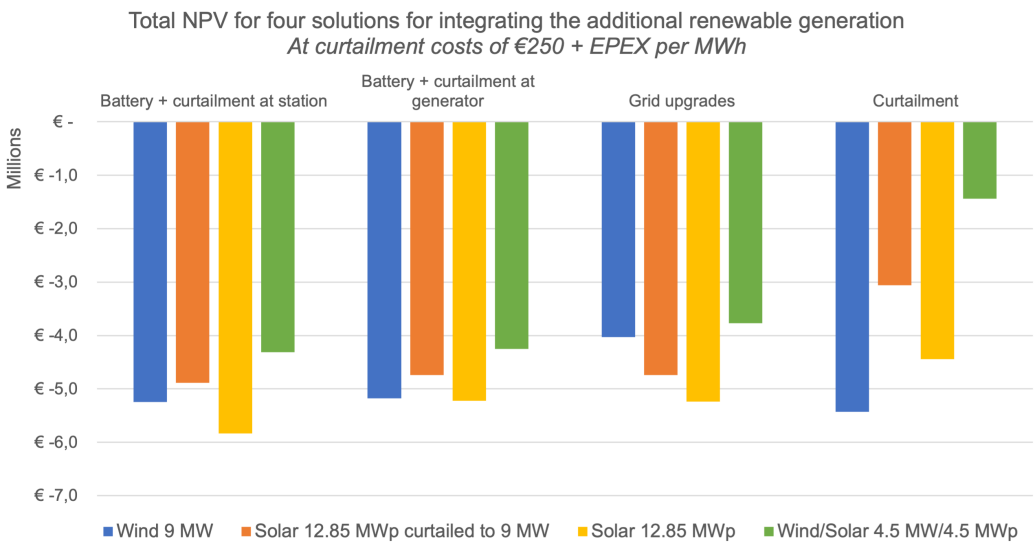


Figure C-1: Diagram of the total NPV associated with different solutions for integrating the additional renewable generation capacity at station Waalsprong without congestion in 2030. Figure was made at curtailment costs of €250/MWh + EPEX prices.

Decreased curtailment costs
Second, the scenario without subsidy costs was evaluated. For the costs of the guarantees of origin, a price level of €7 per MWh was assumed, which is the current[1] average price of Dutch wind- and solar-generation certificates (Wielders et al., 2020). Using this price level, the resulting curtailment costs decrease from €125 + EPEX to €7 + EPEX per MWh. Tables C-3 and C-4 contain the outcomes of the MATLAB runs with these curtailment costs. Compared to the original outcomes, the battery makes significantly less cycles at both locations, leading to an increase in curtailment volume compared to the original outcomes. This is an expected effect: if curtailment becomes less expensive or even profitable during moments with negative power prices, the optimisation will prefer curtailment over using the battery more often.

The curtailment costs for the DSO without battery are low for all generation scenarios, the highest costs are present for the wind scenario. Using the battery + curtailment system still leads to a major decrease in annual curtailment cost when compared to the original situation without the system, as can be seen in tables C-4 and C-3. The tables show almost no differences between connecting the battery + curtailment system at the substation or at the generator: only minor changes in battery operating profit and number of cycles are present. For all generation scenarios except wind, connecting the battery system at the generator increases battery operating profit. This might be caused by more generation load being available for use by the system there.

The CBA results for this scenario are plotted in figure C-2. When comparing the four solutions included in the figure, the first effect of reducing the curtailment costs is obvious: curtailment is the most cost-effective solution for all generation scenarios. When disregarding the curtailment option, the results vary among the generation scenarios. For integrating the 9 MW wind and the combined wind/solar generator grid upgrades lead to fewer costs. For both solar scenarios, the battery + curtailment scenario at the generator results in fewer costs. The difference is caused by the battery system operating profit from charging and discharging: for both solar scenarios, the battery realises a significant profit of 4-6k€ per year for the solar generator connected at 70% and connected at 100%.

Overall, leaving the subsidy out of the curtailment costs does not change the comparison between the battery and curtailment system and grid upgrades all that much. The same patterns are visible as in the original CBA: for both solar generators, the battery + curtailment system located at the generator has a cost advantage over the other solutions, except for the curtailment solution. This cost advantage has grown larger at the lower curtailment cost level, which makes sense: at lower curtailment costs, any solution including some curtailment will show a cost decrease. For the wind/solar scenario upgrading the grid shows a minor advantage, which was more pronounced in the original simulation with higher curtailment costs. For the wind scenario, grid upgrades resulted in lower costs in the original scenario, whereas the battery + curtailment system located at the substation now has a slight cost advantage.

Of course, this simulation does increase the cost advantage of the curtailment option. However, as discussed in 7-6, curtailment might not always be the most desirable option, even if it is cost-effective.

[1] No information is available on future prices of guarantees of origin. The market is relatively non-transparent, making it difficult to predict prices.

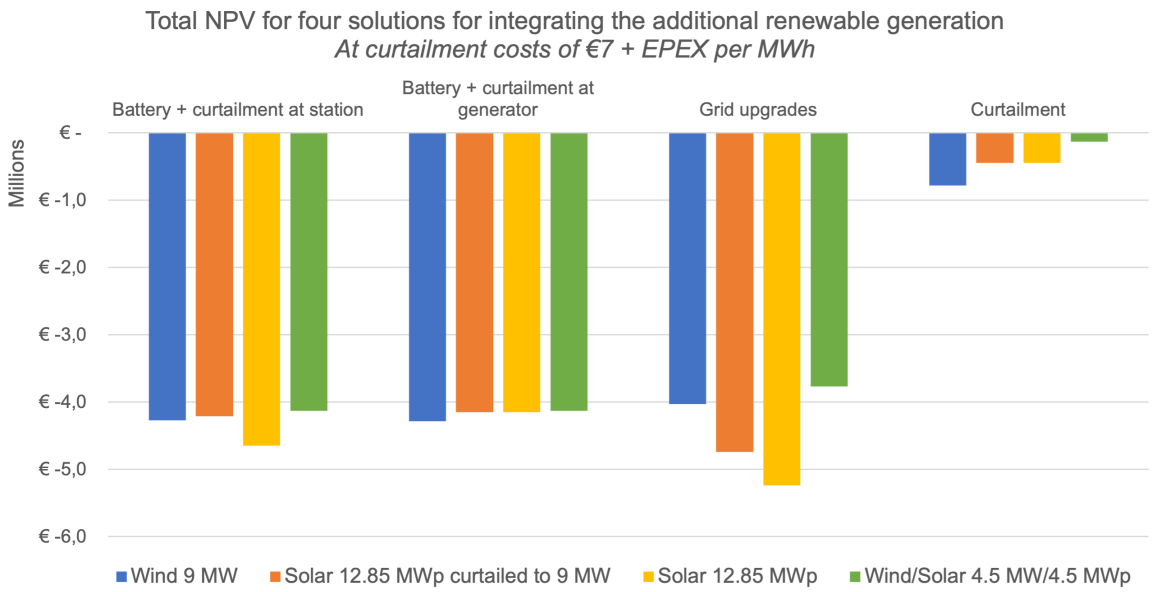


Figure C-2: Diagram of the total NPV associated with different solutions for integrating the additional renewable generation capacity at station Waalsprong without congestion in 2030. Figure was made at curtailment costs of €7/MWh + EPEX prices.

Table C-3: Overview of model output values for curtailment costs of €7/MWh + EPEX prices, with the battery and curtailment system located at the **substation**.

	Curt. volume w/o bat. (MWh)	Curt. volume w. bat. (MWh)	Curt. costs w/o bat. (k€)	Curt. costs w. bat. (k€)	Bat. operating profit (k€)	Cycles
Wind 9 MW	658	358	27	8.2	6.3	30
Solar 9 MW (12.85 MWp at 70%)	392	253	10	2.4	3.4	14
Solar 12.85 MWp	566	365	15	4.1	4.2	20
Wind/Solar 4.5/4.5 MW	185	100	4.7	0.2	3.0	8

Table C-4: Overview of model output values for curtailment costs of €7/MWh + EPEX prices, with the battery and curtailment system located at the **generator**.

	Curt. volume w/o bat. (MWh)	Curt. volume w. bat. (MWh)	Curt. costs w/o bat. (k€)	Curt. costs w. bat. (k€)	Bat. operating profit (k€)	Cycles
Wind 9 MW	658	358	27	8.2	5.8	30
Solar 9 MW (12.85 MWp at 70%)	392	253	10	2.4	4.5	14
Solar 12.85 MWp	566	365	15	4.1	7.8	24
Wind/Solar 4.5/4.5 MW	185	100	4.6	0.2	3.1	8

C-0-2 Sensitivity analysis: battery system costs

The battery system costs used in the main CBA analysis of this thesis (Chapter 6-2) were adapted from the medium-price scenario in the IRENA costs of service tool. This tool was developed in 2017 and estimates battery prices for the years 2020, 2025 and 2030. Research by the DoE has shown that the high-prices scenario of IRENA's tool (326 USD/kWh by 2030) has already been surpassed. Therefore, this sensitivity analysis will use the lowest-cost scenario for 2030 (U.S. Department of Energy, 2020). The lowest storage prices for LFP as estimated by IRENA are 77.4 USD/kWh (IRENA, 2017a). The original costs considered

were 224.1 USD/kWh; thus the new price amounts to a reduction of battery system costs of 65%. The new battery capital costs were integrated into the MATLAB and excel models to generate the results plotted in figure C-3.

The results from reducing the battery system costs are encouraging for batteries: the battery + curtailment system has a lower-cost NPV than grid upgrades for all considered generation scenarios. For the wind generator, the battery + curtailment systems at both locations carry a lower cost than curtailing the excess wind power generated or upgrading the grid. For the 100%-connected solar scenario, the battery + curtailment system at the generator results in the least costs for the DSO. Overall, a reduction in battery system costs will give the battery + curtailment system a large cost advantage over grid upgrades. These results indicate that if battery prices will fall to 77.4 USD/kWh by 2030, the business case for using batteries instead of grid upgrades will become compelling at station Waalsprong. To further investigate this effect, table C-5 was created. It shows at which LFP battery price level the NPV of the costs of applying the battery + curtailment system is equal to the NPV of the grid upgrade costs over the 50 year period for station Waalsprong. The cost parity range is between €146 and €227 per kWh for the battery system - and with the current rapid decrease in battery system prices, even the lowest price level could be feasible by 2030.

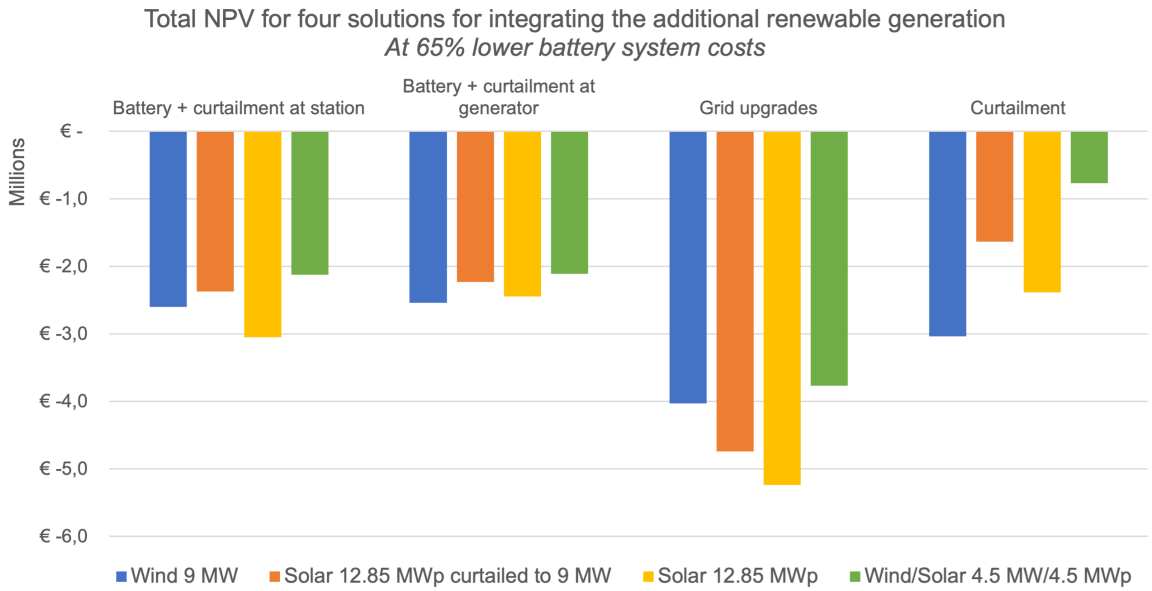


Figure C-3: Diagram of the total NPV associated with different solutions for integrating the additional renewable generation capacity at station Waalsprong without congestion in 2030. Figure was made 65% lower battery system costs compared to original figure in CBA analysis.

Table C-5: Battery costs (€ /kWh) for which using the battery + curtailment system results in the same NPV of costs and benefits as upgrading the network at station Waalsprong. Battery costs are the capital costs of the battery system, excluding the inverter.

Battery system location	Additional generator	2030 Battery costs per kWh for cost parity with grid upgrade
Bat. + curt. at station	Wind 9 MW	€ 146
	Solar 12.85 MWp curt. to 9 MW	€ 201
	Solar 12.85 MWp	€ 192
	Wind/Solar 4.5/4.5 MW	€ 159
Bat. + curt. at generator	Wind 9 MW	€ 150
	Solar 12.85 MWp curt. to 9 MW	€ 210
	Solar 12.85 MWp	€ 227
	Wind/Solar 4.5/4.5 MW	€ 160

C-0-3 Sensitivity analysis: battery learning rate

The battery companies interviewed during this thesis[2] both agreed that the reduction in costs for battery energy storage systems was faster than they had previously anticipated. An expert from GIGA storage noted that the current price per kWh of storage was one-third of the price it was two years ago, thanks to significant technological breakthroughs in LFP cooling technology. These kinds of breakthroughs are hard to estimate with a learning curve, but the 24% cost reduction per 18 years might be on the low side of reality. Studies on the learning rate for Li-Ion batteries have found cost reduction rates between 13-17% per year (Ziegler & Trancik, 2021). To see the effect of faster learning or further breakthroughs, an analysis will be made at a learning rate of 50%. The new battery learning rates were integrated into the MATLAB and excel models to generate the results plotted in figure C-4.

By increasing the learning rate, a similar effect as witnessed in the sensitivity analysis for battery costs, in appendix C-0-2 is visible. Reduced battery costs for the second and third replacement batteries in the 50-year period lead to reduced system costs overall and cause the battery + curtailment system to become a less expensive option than grid upgrades for all generator scenarios at station Waalsprong.

[2]GIGA storage and Alfen

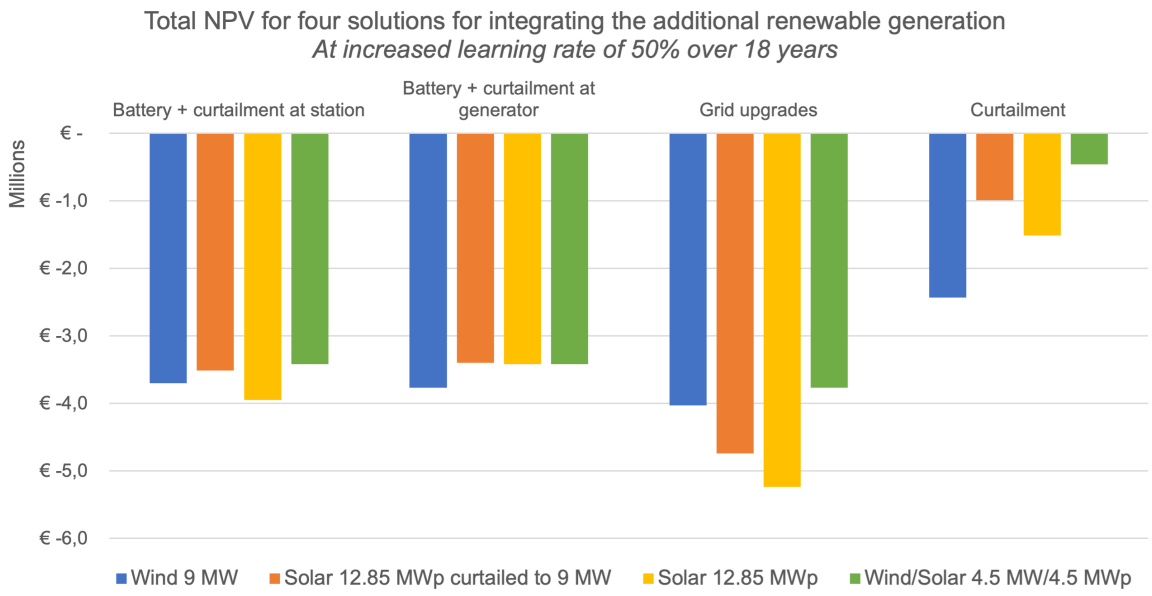


Figure C-4: Diagram of the total NPV associated with different solutions for integrating the additional renewable generation capacity at station Waalsprong without congestion in 2030. Figure was made at a battery system learning rate of 50%, which is double the learning rate of the original figure in the CBA analysis.

C-0-4 Sensitivity analysis: grid upgrade costs

For determining the costs of the grid upgrade, average values for the MV network and HV/MV stations from (CE Delft, 2017) were used. These values were deduced from the total replacement value of the Dutch network in 2017. Next, the number and size of the main elements in the network were gathered, and combined with their average value to calculate the total replacement value of the Dutch grid and specific components. The resulting values were then compared to similar studies, and by combing results, final cost levels per component were developed.

However, by averaging over the entire Dutch power network, the (often large) differences between specific locations disappear. There are numerous locations where upgrading the grid is likely to be substantially more costly than these average numbers indicate[3].

To account for this effect, the iterations of the CBA were performed to find the grid upgrade cost level at which grid upgrades are at cost parity with the battery + curtailment system for every generator scenario and system location. Results from this exercise have been included in table C-6. The cost level used in the original CBA was €250 per kW for HV/MV stations and €705 per kW for MV network, resulting in a total cost of €955 per kW for the grid upgrades. As can be seen from table C-6, the cost parity levels for both solar scenarios, at both system locations, are already below this value. This indicates that using the battery + curtailment system is less expensive than upgrading the network at the original cost level. For

[3]These can either be densely populated areas, where it is challenging to open up the streets to replace underground cables, or isolated areas, such as the Waddeneilanden, where cables need to pass through water to reach the islands.

all other scenarios, the grid upgrade cost level is higher, but not immensely so. These results demonstrate that if upgrading the network at Waalsprong is 18% more expensive than average cost levels, using the battery + curtailment system results in fewer costs for integrating the researched generator scenarios. It is unknown if an 18% increase in cost levels could occur at Waalsprong. However, there are certainly harder to reach places in the Netherlands where such a cost level does not seem unlikely. If the same comparison of grid upgrade costs and battery system costs would be made in such a place, the battery system might come out at an advantage.

Table C-6: Overview of grid upgrade costs (€ per kW) for which the battery + curtailment system reaches cost parity with grid upgrades over the total period of the CBA analysis, for each considered scenario and system location at station Waalsprong

Battery system location	**Additional generator**	**Grid upgrade cost per kW for cost parity with bat. + curt. system**	**Change relative to original cost level**
Bat. + curt. at station	Wind 9 MW	€ 1.141	+19%
	Solar 12.85 MWp curt. to 9 MW	€ 903	-5%
	Solar 12.85 MWp	€ 946	-1%
	Wind/Solar 4.5/4.5 MW	€ 1.074	+12%
Bat. + curt. at generator	Wind 9 MW	€ 1125	+18%
	Solar 12.85 MWp curt. to 9 MW	€ 881	-8%
	Solar 12.85 MWp	€ 839	-12%
	Wind/Solar 4.5/4.5 MW	€ 1.062	+11%

Appendix D

Overview of conducted interviews

Table D-1 gives an overview of the interviews conducted during the final phase of this thesis. The different parties were selected to gather insights from a broad range of stakeholders connected to the implementation of utility-scale battery energy storage systems in the Netherlands.

Table D-1: Overview of the interviews conducted during this thesis.

Name	Company	Function	Date
Ton van Cuijk	Enexis	Senior DSO Architect	29/4/2021
Martijn Douwes	Gasunie	Technical advisor long term energy system planning (One of the authors of II3050)	14/5/2021
Maurice Koenen	Greenchoice	Manager Sourcing & Portfoliomanagement	20/5/2021
Arjan van Voorden	Stedin	Expert Asset Management	31/5/2021
Hans van der Spek Stefan Olsthoorn	Energy Storage NL FME	Program director CleanTech Holland Platform manager Energy Storage NL	2/6/2021
Anonymous	ACM	Energy department	3/6/2021
Maarten Quist	GIGA Storage	COO	7/6/2021
Maarten Afman	Liander	Senior Business Market Analyst	8/6/2021
Ferdinant Visser	Alfen	Project Manager R&D	10/6/2021
Daan Terpstra	Vattenfall	Manager Vattenfall Flexibility Services (Previously Team lead battery projects)	11/6/2021

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