

System Effects of Cross-Border Transmission Capacity and Seasonal Storage on the Future Dutch Power System

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Summary

The Dutch government aims at 70% of electricity production from renewable energy sources in 2030 in order to reach a CO₂ emission reduction of 49% as compared to 1990 levels (Rijksoverheid, 2019). With the increasing share of variable renewables in the European power system, it becomes increasingly more important to find a way to deal with generation volatility. The Northwest European electricity system is particularly suitable for wind energy due to its vicinity to the North Sea. The large share of wind power generation can cause seasonal flexibility needs in the Northwest European power system. This study researched two possibilities to deal with the seasonal flexibility needs because of a large share of wind energy production in the Netherlands: seasonal energy storage and cross-border transmission capacity. The study focuses on the system effects in the Dutch electricity market.

Currently, hydrogen storage is the only suitable seasonal storage option in the Netherlands. Hydrogen can be produced from electricity by electrolysis, for which overproduction hours of renewables can be used. Hydrogen-based energy storage differs from other storage technologies because it also offers the possibility to sell hydrogen directly in the hydrogen market.

Hydrogen-based energy storage potentially overlaps or complements the system benefits of cross-border transmission capacity. Together with cross-border transmission capacity, hydrogen storage can positively influence the effects of renewable energy on the Dutch power system. This research aims at gaining more insight into these system effects of both storage and interconnection capacity in case of a large share of wind energy in the system. The affordability and complementarity in deployment are analysed.

CE Delft's electricity market model Powerflex is used for this study. Using a model allows to capture the dynamics of the electricity market and to run several scenarios, which can be analysed quantitatively. Powerflex is an hourly unit commitment economic dispatch model, covering the Dutch and German electricity market and the interaction between the markets through cross-border transmission capacity. The model optimises the electricity market operation by minimising total system costs. Capacity investments are not optimised in this model and CO₂ emissions cannot be extracted from the model results.

The model is extended with a storage function, which is modelled through dynamic programming and captures the price responsive behaviour of the storage in the market. It is assumed that hydrogen production by electrolysis can be competitive to hydrogen produced by SMR in 2030 and therefore the hydrogen price is based on the production costs of hydrogen by SMR. The hydrogen demand is unrestricted and the hydrogen price does not respond to fluctuations in supply.

Some limitations to the model arose in the verification and validation process of the implementation of the storage function. The model cannot converge for scenarios with a large share of renewables when limited flexible capacity is available in the system. Moreover, results regarding dispatch costs are considered invalid due to an identified model artefact.

Scenarios with varying storage capacity and cross-border transmission were run. Storage capacities are indicated in Table 1 and they are a percentage of the negative residual demand in the Netherlands. These storage capacities are run in combination with interconnection capacities of 3.75 GW, 5 GW and 6.25 GW.

It can be concluded that cross-border transmission capacity leads to small system benefits if it is used to interconnect areas with similar RES potential, weather patterns and demand patterns. Moreover, it was found that storage capacity complements (increases the need for) interconnection capacity deployment, while interconnection capacity does not influence the need for storage capacity. Additionally, storage capacity leads to fewer price extremes and a reduction of curtailment needs. In the model results, storage capacities larger than 50% storage are not justifiable as they lead to declining marginal

Table 1: Installed storage capacities representing 25%, 50% and 75% storage in the Netherlands.

	25% Storage	50% Storage	75% Storage
Charging capacity [GW]	3.75	7.5	11.25
Energy storage capacity [GWh]	911.04	1824.27	2737.50
Discharging capacity [GW]	3.75	7.5	11.25

benefits. A storage capacity of 50% of the negative residual demand in the Netherlands is found as an upper bound.

Limitations to this research are the limited scope with the Netherlands and Germany, the unrestricted hydrogen demand and the limited number of flexibility options. This results can be influenced if a more diverse set of flexibility options is modelled, such as curtailment, demand response and different storage technologies. Moreover, an influence of interconnection on storage utilisation can be expected in reality because the system benefits of interconnection capacity are larger in reality. A more diversified storage portfolio and more flexibility options is expected to lead to smaller storage requirements.

Practical implications for several actors in the power sector lead to the following recommendations for policy makers. The development of hydrogen storage should be supported because this allows for the integration of RES in the Dutch system. This should be combined with the development of a European interconnected grid and local electricity storage. The latter can reduce the interconnection capacity investments. Moreover, back-up capacity should be secured as profitability of conventional producers goes down when storage is introduced.

Future research should focus on improving Powerflex regarding the convergence issues and odd dispatch costs results. Moreover, a system focusing on the limited predictability of RES, researching a broader set of flexibility options and case-specific cost- benefit analysis can allow for more insights into the system effects of storage and cross-border transmission capacity.

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Introduction

1.1. Context

Since July 2009, the EU aims at reducing greenhouse gas emissions by 80 - 95% by 2050, as compared to 1990 levels (European Commission, 2019). This EU objective influences the current energy system considerably, since the largest part of man-made greenhouse gas emissions is produced by the energy sector. At the moment, nuclear energy, carbon capture and storage (CCS) and a larger share of renewable energy sources are mentioned to make big steps possible for decarbonisation of the European energy system. However, social support is lacking for the large scale deployment of nuclear energy and CCS and it is questionable whether a breakthrough of these technologies will ever happen.

Meanwhile, many EU Member States subsidise electricity generation from renewable energy sources (RES). In 2015, the majority (77%) of new European generation capacity was renewable for the eighth consecutive year, mainly wind and solar panels (solar PV) (European Environment Agency, 2018). The electrical energy demand in Europe is increasingly supplied by variable renewables. The Dutch government aims at 70% of electricity production from renewable energy sources in 2030 in order to reach a CO₂ emission reduction of 49% as compared to 1990 levels (Rijksoverheid, 2019). This study considers a future Dutch and German power system with a large share of variable RES in 2030.

With the increasing share of variable renewables in the European power system, it becomes increasingly more important to find a way to deal with generation volatility. Renewable energy sources like wind and solar energy are weather-driven, which leads to forecast uncertainties in the production pattern and a fluctuating energy supply. A larger share of wind and solar generation in the generation mix will lead to larger fluctuations in the power generation pattern, making it more difficult to match demand and supply at all times.

These large variations will require more flexibility of the power system. A power system is considered flexible when it can respond to fluctuations in energy demand and power generation, keeping demand and supply in balance (Huber et al., 2014). In the traditional system, fluctuations were balanced by conventional fossil-fuelled generation. However, the larger share of variable renewables in the power system thus implies more need for flexibility to compensate for the generation variability that is inherent to RES (Brouwer et al., 2014). Moreover, renewable energy sources impact all power system operational time frames in varying degrees which requires different flexibility solutions (Lund et al., 2015).

Five types of flexibility solutions for the power system can be identified, namely demand response, variable renewable energy curtailment, flexible back-up generation, electrical energy storage and interconnection capacity (Verzijlbergh et al., 2014). These measures are partly complementary, which implies that a combination of these solutions will be needed to offer flexibility to the grid on all levels and timescales.

In the very short term, that is 1 ms-5 minutes, solar PV and wind generation intermittency causes deviations in network frequency and voltage levels. Short duration fluctuations are demand and supply imbalances between 5 minutes and 1 hour, whereas an imbalance is of intermediate duration when it occurs for 1 hour to 3 days.

Wind and solar generation show a seasonal production pattern within a year; wind power generation in Europe is much larger in winter than in summer whereas the opposite holds for solar power generation (Heide et al., 2010). The European demand curve shows a similar pattern to that of wind power production, with a larger demand and wind production in winter. However, the seasonal variation of wind power production is much larger than that of the load. With a large share of renewables in the European generation mix, this implies long-term large excesses or shortages of energy during periods up to several months.

The power system of the future will need long-term flexibility in order to deal with such large seasonal fluctuations. Curtailment would be an option, but this means that less wind or solar power is used than is available at a certain time (Lew et al., 2013). This leads to energy losses in certain periods, while in other periods there is a lack of variable renewable generation due to a different season.

Instead, the excess of energy could be shifted temporally, by using seasonal storage, and spatially by transmission of electric power over long distances (Energy Delta Institute, 2012). Energy storage can store excess electricity production and discharge this electricity at moments when demand is high and production low. Multiple studies have shown that a larger interconnected grid and energy storage are both needed to reach a system with a large share of renewables (Lund et al., 2015; Steinke et al., 2013). In Europe, where countries are close to each other, this means that cross-border transmission capacity expansion will be needed to interconnect the electricity markets of European countries.

1.2. Problem formulation

Europe is large enough to be impacted by different weather systems at the same time, which is leading to varying wind power generation, solar power generation and demand patterns among European countries. Wind power and solar power can partly equal out each others generation pattern, but an optimal ratio of wind energy and solar energy in one system is difficult to achieve because one country is more suitable for wind energy whereas other countries are more suitable for solar energy.

The Northwest European electricity system is particularly suitable for wind energy due to its vicinity of the North Sea. The amount of wind generation capacity on the North Sea is therefore expected to increase in the coming years, which could contribute cost-effectively to the European energy transition (Afman and Rooijers, 2017). Tenders for the construction of such wind parks have recently been won at very low tender bids; where at first subsidies were needed for wind energy projects, currently the first projects are sold without any help of subsidy. If wind energy on the North Sea continues to develop rapidly, it could possibly reach a level of 50 GW in 2050 (Afman and Rooijers, 2017). Such a large increase in fluctuating wind power leads to large correlated variations in the Northwest European energy supply (Monforti et al., 2016).

The large share of wind power generation on the North Sea is likely to cause long-term flexibility needs in the Northwest European power system. Moreover, wind production leads to a lower system marginal costs and thus to a lower average annual electricity price. The electricity price can become negative in certain hours of the year. Such very low electricity prices and curtailment of wind energy production should be avoided in order to keep wind energy production profitable.

This study will research two possibilities to deal with the long-term flexibility needs because of a large share of wind energy production in the Netherlands: seasonal energy storage and cross-border transmission of electricity to neighbouring countries.

Seasonal energy storage

Seasonal energy storage requires energy storage on the time frame up to months, therefore it is needed to look at bulk energy storage technologies. Van Staveren (2014) identifies four types of bulk energy storage, namely flow battery storage, compressed air energy storage, pumped hydro storage and hydrogen storage. However, not all these techniques can store energy for periods of months (SBC Energy Institute, 2014). Flow battery storage and Compressed Air Energy Storage can reach large storage capacities but can store this energy only for multiple hours up to days. Currently, two possibilities for seasonal storage can be identified: pumped hydro storage and hydrogen-based energy storage.

Pumped hydro storage capacity in Northwest Europe is limited due to geographical circumstances and will therefore not be sufficient to reach the long-term flexibility needs in the North Sea region. Moreover, the Netherlands in particular is very unsuitable for pumped hydro storage. It is thus needed to investigate hydrogen-based storage as the only remaining seasonal storage option.

Hydrogen-based energy storage means that excess electricity is converted into hydrogen and this hydrogen can be re-converted to electricity at moments of electricity shortages. Hydrogen-based energy storage differs from other storage technologies because it also offers the possibility to sell hydrogen directly in the hydrogen market. This not only generates an extra revenue stream for this technology, but is also expected to influence the bidding behaviour of hydrogen-based energy storage units in the market. The charging or discharging decision of this type of energy storage is not only dependent on the electricity price but also on the hydrogen price.

Currently, multiple parties in the energy sector see the production and storage of hydrogen as an essential link in the energy transition. The number of projects around the conversion of electricity into hydrogen is increasing. For example, the Dutch, German and Danish Transmission System Operators (TSOs) formed a consortium in order to build energy hubs on islands in the North Sea to accommodate the expected large offshore wind power capacities. Apart from transporting electricity to the North Sea countries and connecting the electricity markets around the North Sea, these energy hubs should facilitate the conversion of electricity excesses into hydrogen.

Cross-border transmission capacity

Cross-border transmission capacity allows for international trade of electricity and in that way it can balance out fluctuations caused by RES. Investments in cross-border transmission capacity are capital intensive, need bilateral coordination between TSOs and have long construction periods and lifetime. Timely decisions about the construction of cross-border transmission capacity are needed, while future power system developments are uncertain.

The benefit of a larger cross-border transmission capacity can be lower in a system with a large share of correlated wind energy production in neighbouring countries. When there is much wind energy in the electricity system, electricity prices in all countries are likely to be lower. In the most extreme case, electricity export to neighbouring countries will not prevent the electricity prices from decreasing because the electricity price in neighbouring countries is also low. Export to neighbouring countries will then also not decrease the need for curtailment of wind energy.

Relation between energy storage and cross-border transmission capacity

The need for interconnection as a long-term flexibility measure is also dependent on investments in seasonal energy storage, which are made by other actors in the power system. Moreover, it has been shown that energy storage and transmission expansion are partly complementary and both are needed to reach a 100% renewable European power system (Steinke et al., 2013).

Brancucci Martínez-Anido and De Vries (2013) showed that pumped hydro storage utilisation complements cross-border transmission capacity in a system with a large share of variable renewable energy. In such system, cross-border transmission capacity is needed to transport electricity to and from the storage facilities, according to the needs caused by wind and solar PV generation correlations and demand in different countries. The technologies are substitutes when it comes to reducing annual dispatch costs, CO₂ emissions and the need for renewable energy curtailment in a system with a small variable renewable generation capacity. However, using both energy storage and cross-border transmission capacity together has an even stronger positive effect on these system variables.

On this basis, hydrogen-based energy storage, as another form of energy storage, potentially also overlaps and complements cross-border transmission capacity. The interaction of transmission capacity with energy storage will be dependent on the size of the transmission capacity and the dimensions of the energy storage.

1.2.1. Research problem

The Dutch government aims at affordability, reliability and sustainability of the Dutch electricity market and this thesis will look into the affordability of the market. Hydrogen storage is thus expected to play an important role in the energy transition. Together with cross-border transmission capacity, hydrogen storage can positively influence the effects and integration of renewable energy on the Dutch power system. However, it is unclear to what extent hydrogen storage should be developed and this thesis aims to shed some light on this. How do the system effects of hydrogen storage overlap and complement the system effects of cross-border transmission capacity? Moreover, to what extent do hydrogen storage and cross-border transmission capacity lead to positive effects, including affordability based on dispatch costs, on the Dutch electricity system?

This research will focus on the system effects of seasonal energy storage and cross-border transmission capacity on the future Dutch power system with a large share of wind energy. System effects in this context are the effects on the Dutch electricity market regarding the dispatch of both flexibility options. Therefore, the main research question is formulated as follows:

What are the system effects of cross-border transmission capacity and seasonal storage on the future Dutch power system with a large share of wind energy?

The above question is supported by the following two sub-questions:

1. How do seasonal storage and interconnector deployment affect each other in serving flexibility?
2. To what extent do seasonal storage capacity and interconnector capacity influence the dispatch costs?

1.3. Relevance

The results of this thesis offer useful insights from a societal perspective, namely for several stakeholders in the power system. The results will be interpreted for the Transmission System Operator TenneT (TSOs) who has to coordinate capital intensive investments in cross-border transmission capacity bilaterally, taking into account the long construction periods and long lifespan of these assets. Moreover, an interpretation in terms of affordability for consumers and conventional and renewable power producers will be given.

The interaction of both long-term flexibility measures is also valuable information for possible investors in order to decide whether to invest in hydrogen-based energy storage or not. Results can also be useful for Dutch policy makers, who might need to accelerate seasonal energy storage developments in order to reach the decarbonization goals for 2050 set by the European Commission, by for example subsidising certain technologies.

1.4. Methodology

To find an answer to these research questions, firstly an extensive literature review is performed. After that, the model Powerflex will be used, as using a model allows to capture the dynamics of the electricity market and to run several scenarios, which can be analysed quantitatively.

Powerflex is a unit commitment economic dispatch model aiming to minimise total system cost. Powerflex models the Dutch and German electricity market and their interactions through cross-border transmission capacity. The model optimises the power system operation, which means that it optimises dispatch in the market and matches demand and supply in each hour of a predefined year. The model does not contain an investment module, which implies that investments in storage capacity and interconnection capacity cannot be optimised. Moreover, CO₂ emissions cannot be calculated from the model.

Powerflex is extended with a storage module for the purpose of this study. This storage module will be built with a cost-minimising objective according to the dynamic programming algorithm. Realistic bidding behaviour is needed to analyse the effects of hydrogen-based energy storage in the Dutch power system.

Regarding the hydrogen market, the assumption was made that hydrogen production by electrolysis can be competitive to hydrogen produced by SMR in 2030 (Hers et al., 2018). Therefore, hydrogen is sold at the production costs of steam reforming of natural gas (SMR), which is an hourly price curve dependent on the price of natural gas. Hence, an hourly hydrogen market is assumed and SMR always sets the price. SMR is thus the only competitive option in the hydrogen market. Electrolysis always supplies a part of the hydrogen demand; the rest of the hydrogen demand is always supplied by SMR.

Regarding the scope of the study, it is assumed that all coal plants in the Netherlands are shut down by 2030. Additionally, all coal plants and lignite plants with a lifespan until 2030 in Germany are shut down and no new coal and lignite plants will be built. In this way, Germany has a much lower coal and lignite capacity than the most 'green' vision 4 scenario of ENTSO-E.

1.5. Thesis outline

Chapter 2 reviews literature on the effects of variable renewables on the power system, the model requirements to capture these impacts and the system benefits of seasonal storage and interconnection capacity. Chapter 3 contains a description of the Powerflex model. Chapter 4 gives a mathematical formulation to conceptually design the storage function. This conceptual design is translated so that it is suitable to be dynamically programmed in Chapter 5. Thereafter, Chapter 6 discusses the tests that have been performed for verification and validation of the model. Chapter 7 shows the scenario design of this study and the corresponding scenario results. Chapter 8 discusses these results, relates them to conclusions from literature and limitations of the study and interprets the results for different power sector actors. In Chapter ??, answers to the research questions are formulated and followed by a set of recommendations. Chapter 10 gives a personal reflection on the process of writing this thesis.

2

Literature review

This literature review will firstly explain more about the impacts of variable renewable energy supply on the power system and the key performance indicators (KPIs) that can be used to measure the flexibility requirements in the system. Secondly, several aspects for modelling flexibility is discussed, each having their own strengths and weaknesses in representing the power system with a large share of renewables in a realistic way. Thirdly, different methodologies for electricity market modelling will be elaborated on, in order to explain how each methodology takes a different viewpoint on the same system and to what extent Powerflex is suitable for this study. After that, other studies about the system effects of storage, transmission capacity and a combination of these two will be analysed in order to see what conclusions can already be drawn from other studies. Finally, it will be discussed how storage can be modelled and what data is needed to model hydrogen storage specifically.

2.1. Impacts of variable renewables on the power system

Uncertainties in wind and irradiation forecasts make it difficult to respond to upcoming fluctuations. The fluctuations are visible on different timescales (Lund et al., 2015). Seasonal variability of wind and solar generation can be seen within a year. These long-term variations are caused by the seasons; wind power generation in Europe is much larger in winter than in summer whereas the opposite holds for solar power generation (Heide et al., 2010). Heide et al. (2010) made this seasonality visible with two scenarios for a fictitious future Europe: a 100% wind-only scenario and a 100% solar-only scenario, see Figure 2.1. It can be seen that the demand curve also follows a seasonal pattern and has a maximum in winter and a minimum in summer. However, the strength of the seasonal variation of wind power production is much larger than that of the demand.

A large share of renewable energy sources (>80% of generated energy) will thus increase the variability of generation, which implies a larger variability in residual demand in the future. The residual demand is the demand minus generation by variable renewables. An illustration can be seen in Figure 2.2. Residual demand ramps can be used as a measure of flexibility requirements in a power system, as flexible resources need to balance each change in residual demand to maintain system stability (Huber et al., 2014).

There exist several possibilities to measure the flexibility requirements in the power system. One of these methods is to use the maximum negative residual demand as a measure for the flexibility requirements in the power system and this is the method used in this research. A negative residual demand occurs when there is overproduction by renewable energy sources; more renewable energy is produced than is needed to fulfil the demand. The residual demand decreases even more due to limited flexibility of the generation portfolio caused by units such as must-run units or plants that supply reserve capacity. Curtailment, a flexibility measure by itself, is needed at moments when the electricity generated by renewables cannot be absorbed by the electricity system due to limited availability of other forms of flexibility. Curtailment can therefore be seen as an indicator of limited flexibility in the power system. Variable renewables also affect the electricity price and operation of thermal generators

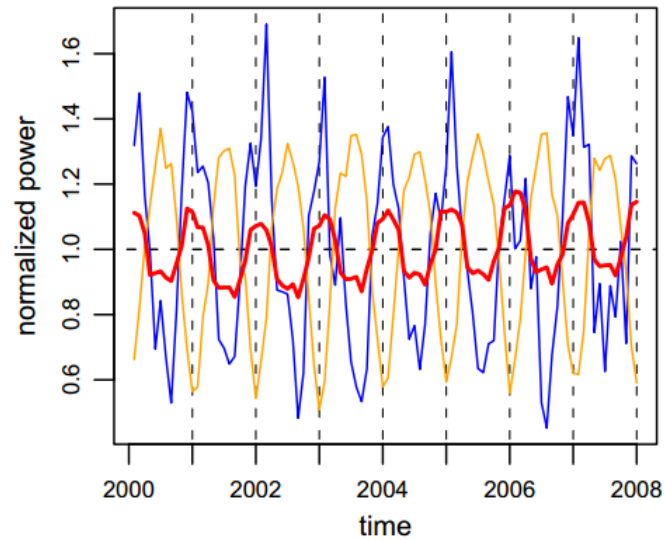


Figure 2.1: Normalized generation time series aggregated over Europe for wind power (blue), solar power (orange), and demand (red) (Heide et al., 2010)

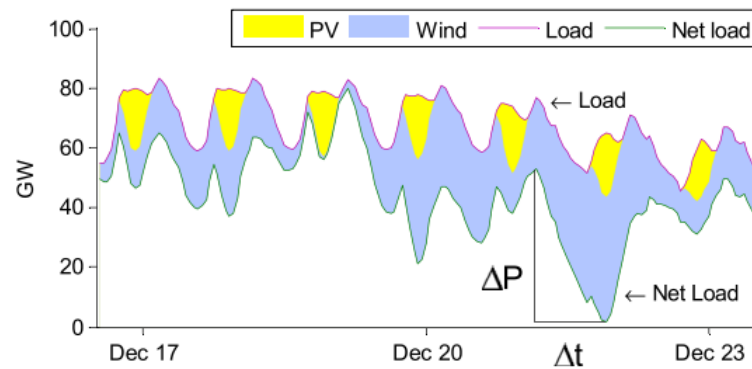


Figure 2.2: Residual demand ramps in a power system with a large share of variable renewables (Huber et al., 2014)

due to their effect on the merit order. The merit order contains the supplier bids in an ascending order according to marginal cost (Deane et al., 2017).

The electricity price is set at the intersection of the demand curve with the merit order. An increase in variable renewable energy causes the merit order curve to shift to the right because of the low or near zero marginal costs of renewables. The intersection of the demand curve and the merit order shifts to a lower marginal price, thus leading to a lower electricity price on average. At the same time, higher production by variable renewables will also lead to larger price spikes due to the weather-driven fluctuations. Overproduction can lead to very low prices whereas underproduction can cause prices to rise to extremely high levels.

Thermal generators will thus shift to the right in the merit order, leading to less production hours or even displacement of these facilities. Which generators will be displaced depends primarily on the merit order; the units with highest marginal cost are displaced first. This is called merit order displacement; fuel and CO₂ prices might cause coal plants to switch with natural gas fired power plants leading to displacement of the coal plants. However, inflexibility displacement is also possible, which means that inflexible capacity might operate fewer hours as the system needs flexibility to balance a larger share of variable renewable generation.

Renewables thus reduce the share of thermal energy generation by merit order displacement and inflexibility displacement of thermal plants, which implies less CO₂ emissions and lower dispatch costs. On the other hand, the larger variability in residual demand and uncertainty of wind and irradiation forecast errors affects the operation of thermal plants. The power plants will have to run more part-load and to start up and shut down more often in order to balance demand and supply at all times (Brouwer et al., 2014). This required flexibility implies a higher fuel consumption by the thermal power plants which can increase their CO₂ emissions and dispatch costs.

2.2. Model requirements to capture the impact on the KPIs

The impacts of variable renewables on the power system operation can be seen at two main variables, namely curtailment and dispatch costs. These variables can be influenced by the presence of flexibility measures in the system and can thus be used as performance indicators of flexibility options in a system with a high share of variable renewables. In order to capture the impacts on the performance indicators with a model, the model should fulfil certain requirements. Table 2.1 gives model requirements to model the specific power system impacts of a large share of variable renewable energy sources, based on the study by Brouwer et al. (2014).

Table 2.1: Model requirements to model the specific power system impacts of a large share of variable renewable energy sources

Model requirement	Modelled impact of RES
RES power production timeseries (time step \leq 1h)	<ul style="list-style-type: none"> - Curtailment needs - CO₂ emissions - Inflexibility displacement
Operational constraints of thermal generators	<ul style="list-style-type: none"> - Curtailment needs - CO₂ emissions - Merit order displacement
Variable costs of operation (based on fuel and CO ₂ prices)	<ul style="list-style-type: none"> - Merit order displacement
CO ₂ emissions related to operation	<ul style="list-style-type: none"> - CO₂ emissions

Brouwer et al. (2014) performed a detailed literature review on power system modelling and recommend a unit commitment and economic dispatch model with at least a 1 hour time step for modelling the impacts of intermittent renewable energy sources on a low-carbon power system. Such model is able to simulate actual practice and can determine the available flexibility, the costs and the emissions. This section is based on the study by Brouwer et al. (2014).

First of all, it is needed to model the intermittency of variable renewable power production in sufficient detail. In order to capture their system effects, a time series with a time step smaller than or equal to the time step of the model (Brouwer et al., 2014). The time series should span the same year as the demand time series and it should reflect the geographic distribution of the variable renewable production units. Subtracting the variable renewable production time series from the demand time series results into the residual demand time series.

In order to model curtailment of variable renewable energy, the operational constraints of the generators in the generation portfolio, the transmission capacity and the residual load should be modelled. The residual load can be compared to the must-run capacity and the capacity that is needed to supply the load in each hour. When the minimum generation exceeds the residual load, curtailment occurs when the power cannot be used elsewhere by for example interconnectors or electricity storage.

Merit order displacement can be captured by including the variable costs of the power plants in the model. In order to model inflexibility displacement, the operating constraints of the power plants should be included, especially ramp rates and start-up times. Next to that, interconnections may influence displacements as high wind penetration might displace production capacity in neighbouring countries through the export of wind energy.

2.2.1. Aspects relevant for modelling flexibility

One of the aspects which distinguishes different modelling approaches is the way of modelling flexibility. Power system models can be classified according to different concepts, each having their own strengths and weaknesses in representing the power system in a realistic way. Moreover, these concepts differ in modelling complexity due to for instance limited data availability, computing time and validation options.

Currently, few models consider flexible demand and only in a strongly simplified way because it is complex to quantify load shift potentials due to heterogeneous agents and technologies (Keles et al., 2017). Moreover, load shift potentials vary over time and depend on many system characteristics which makes aggregation difficult. The potential is influenced by factors related to user acceptance and user patterns, such as season, day and daytime, the duration of the demand shift, price sensitivity and whether the load should increase or decrease. The data currently available is insufficient to quantify the load shift potential in a more specific way.

Models differ in how they handle the uncertainties that are inherent to renewable energy supply, and in general two types of models exist: deterministic models and stochastic models (Pfenninger et al., 2014; Ventosa et al., 2005). Deterministic models consider single expected (predicted) values for all parameters and thus assume perfect foresight (Keles et al., 2017; Ventosa et al., 2005). There is no uncertainty and all relevant information of future events is known. However, deterministic models can deal with uncertainties if an uncertainty analysis is performed. For an uncertainty analysis, the deterministic model is applied many times while the input data is varied by for example the Monte Carlo approach (Pfenninger et al., 2014). The effects of changes in model inputs on model outputs can then be examined (Pfenninger et al., 2014).

By contrast, in stochastic models, probabilistic distributions are specified for some parameters so that the uncertainty is incorporated into the decisions of the model (Pfenninger et al., 2014; Ventosa et al., 2005). Stochastic models use a modelling method specifically designed to handle uncertainty this way and stochastic programming is an example of such method. However, in stochastic models only a small parameter subset is varied according to available data or the interest of the analyst, which neglects unexpected sources of uncertainty (Pfenninger et al., 2014).

An adequate representation of uncertainties is challenging and increases computation effort. Deterministic power system models already require large-scale programs but it is even more difficult to obtain computationally feasible stochastic models (Keles et al., 2017; Pfenninger et al., 2014). A different approach is to reduce model complexity in such a way that running a deterministic model takes seconds instead of hours, thereby allowing for a comprehensive uncertainty analysis (Pfenninger et al., 2014).

The choice of time scope in a model influences the decision variables and involves different modelling approaches, each having their own level of detail and uncertainty. Power system issues occur on different time scales: from second-by-second balancing of demand and supply to infrastructure design with a lifetime of decades (see Figure 2.3) (Pfenninger et al., 2014). Models covering the long-term are investment and planning oriented, such as generation expansion planning or transmission expansion planning models. The main decision variables in long-term studies are capacity investment decisions, whereas short-term studies consider a fixed maximum capacity of each generator (Ventosa et al., 2005). Short-term models focus on power plant scheduling and load balancing in real-time and use for example start-ups and shut-downs as decision variables (Pfenninger et al., 2014).

Planning studies typically split their time scope into intervals, which are also known as periods (Ventosa et al., 2005). Generating electricity involves many decisions and costs that are related to generator scheduling in the intermediate periods. In the long-term, monthly or weekly operation decisions are needed to schedule hydro reserves, whereas thermal unit commitment decisions in the short-term need intertemporal constraints such as ramp-rate limits (Ventosa et al., 2005).

Moreover, with the increasing share of renewables, the resolution of time but also the resolution of space becomes more important to represent the temporal and spatial weather correlation of renewable energy supply (Pfenninger et al., 2014). Spatial detail is important for renewables as their generation

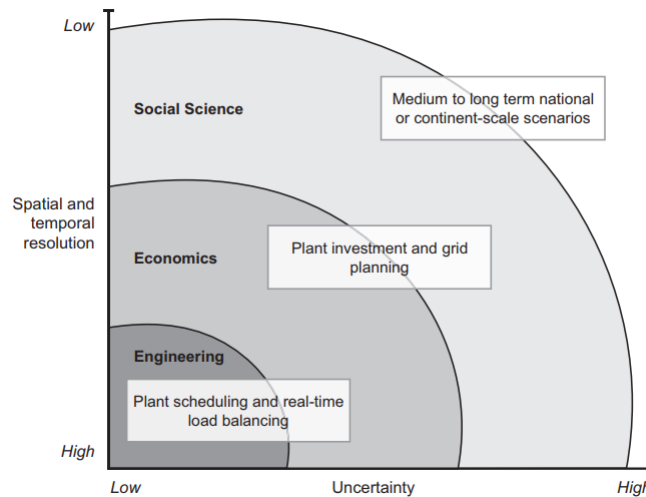


Figure 2.3: Modelling across different time scales (Pfenninger et al., 2014)

costs and economic potential depend on their location. The spatial distribution of renewables can balance their fluctuations and also influences the amount of storage needed (Pfenninger et al., 2014). Temporal detail is needed to capture the variability in renewable energy supply.

Models can address this issue in the following three different ways with increasing data intensity (Pfenninger et al., 2014). Firstly, temporal detail can be added by using capacity factors or load duration curves. Secondly, representative days and seasons can be represented by time slices. The third possibility is to use real time series corresponding to wind or solar potential.

Traditionally, models including the transmission network decouple the market model and network simulations (Keles et al., 2017). These models firstly calculate the generation dispatch results using a simulation or optimisation approach and thereafter use these generation dispatch results to perform a network simulation (Keles et al., 2017). Even though such two-step approach can increase computational performance, it neglects the interaction between network and market or only includes the interaction in an iterative manner. Neglecting the interaction between network and market implies that the influence of network operation on the market is not taken into account, while the market and network operation are highly interlinked.

The development of renewable energy capacity and conventional generation operation and expansion planning have a large influence on the required transmission and distribution network expansion and operation thereof. Including endogenous network expansion within a model is a way to deal with this interlinkage of network and market. However, endogenous network expansion entails an extra highly-complex dimension in a model, including interactions with decentralised generation and consumption, resulting in a computationally challenging and data-intensive approach which is therefore limited in applicability (Keles et al., 2017).

Another challenge to energy system modelling is to capture the human dimension, which will play a large role in how the future energy system will develop. The acceptance and diffusion of new energy technologies such as rooftop PV systems and onshore wind turbines is highly influenced by the risk attitude of investment agents and the public perception (Keles et al., 2017; Pfenninger et al., 2014). The agent behaviour, their individual decisions and the imperfect foresight of market actors will result in different market dynamics and it becomes important to include them in future energy system models (Keles et al., 2017). However, it is difficult to calibrate and validate such models as data is mainly unavailable and assumptions are questionable (Keles et al., 2017).

2.2.2. Model classification

Generally, two categories of energy system models can be identified: top-down models and bottom-up models (see Figure 2.4). Top-down models describe the energy system from a macroeconomic perspective, which means that they capture the influence of the energy system on the rest of the economy (Götz et al., 2012). This type of models is therefore generally characterised by high aggregation levels, both in terms of technological details of electricity production as well as time and space. Such models typically do not consider the level of technical, temporal and spatial detail required to shed light on power system flexibility requirements (Jaccard, 2009). The level of detail of top-down models is insufficient to represent the hourly balance between demand and supply.

Whereas top-down models are based on economic principles, bottom-up models take a technological perspective and have been mainly developed in engineering (Götz et al., 2012). They typically contain technological details and techno-economic parameters and are able to model a large variety of individual technologies and their technological, economic and ecological parameters (Götz et al., 2012). Because of their high technological detail, bottom-up models are most suitable to analyse the effects of interconnector capacity and seasonal storage deployment on the future Dutch power system.

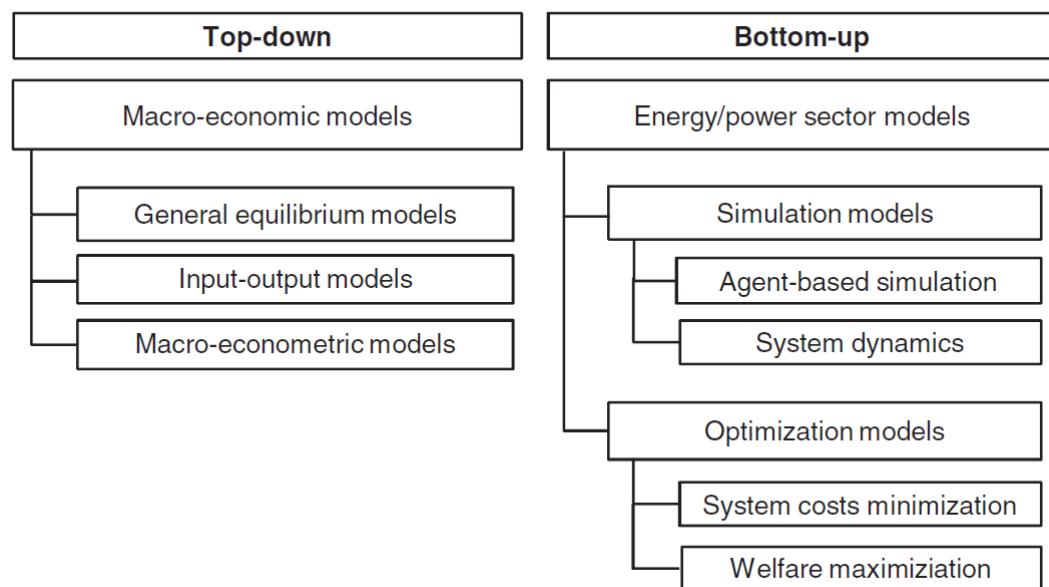


Figure 2.4: Classification of different energy system models (Jägemann et al., 2013)

According to Götz et al. (2012) and Herbst et al. (2012) there are two main approaches of bottom-up models, namely simulation models and optimisation models. Simulation models capture individual decision-making processes based on observations and expectations. They model the influence of aspects like strategic behaviour or incomplete information on the development of the energy system (Jägemann et al., 2013). Examples of simulation models are system dynamics and agent-based modelling.

System dynamics assumes that there are interdependencies between system components which show dynamic changes over time (Herbst et al., 2012). On the other hand, agent-based models capture the individual behaviour and decisions of different market participants, such as transmission system operators, electricity consumers, generating companies, and regulators (Keles et al., 2017). For each agent, the rules they follow and the interactions with the environment are specified and in this way the behaviour resulting from these interactions can be captured (Pfenninger et al., 2014).

Whereas agent-based models and system dynamics may capture the individual behaviour and decisions of different market participants, optimisation models consider a central decision maker's perspective (Keles et al., 2017). Optimisation models calculate a system-wide optimal solution by either

minimising or maximising an objective function which is subject to several predefined boundary conditions. These boundary conditions can be technical, economic and regulatory constraints, such as a CO₂ emission cap, priority feed-in of renewables into the power system or capacity boundaries and ramp rates of power plants (Keles et al., 2017).

The objective function of an optimisation model of the power sector mostly is to maximise social welfare or to minimise total system costs (Jägemann et al., 2013). Social welfare in a power system is defined as the consumer's utility from using electricity minus the cost of generating that electricity. The social welfare maximisation assumes a price elastic energy demand.

However, it is difficult to define the consumer's utility of electricity usage and electricity does not have any close substitutes. Therefore, optimisation models often assume that demand is price-inelastic, which reduces the social welfare maximisation problem into a cost minimisation problem (Jägemann et al., 2013). Note that this assumption leads to a deviation from reality because currently industrial consumers show price-elastic demand and household consumers will follow in the future due to smart charging of EVs for instance.

There are two ways to solve optimisation problems for a power system model: pure economic dispatch models (ED models) and economic dispatch models extended with unit commitment. Models of the latter type are called unit commitment and economic dispatch models (UC/ED models).

In economic dispatch models the system demand is allocated among available generation units with different variable production cost, in order to minimise the total production costs (Galiana and Conejo, 2009). The demand is allocated with respect to the generating unit operational limits and the power balance, which is the total generation plus transmission losses. It is assumed that system voltage and frequency are not affected by the economic dispatch, which implies that direct current power flows are modelled, which is easier than modelling alternating currents. When an ED model takes into account the transmission network, line flow constraints capture the technical limits of the transmission lines. However, thermal power plants can be either online or offline and generally cannot produce under their minimal output level. Furthermore, starting up a thermal power plant implies start-up costs because of the fuel consumption to drive the boiler to its working temperature and pressure during the time these plants are brought up to speed and synchronised to the system (Galiana and Conejo, 2009). Economic dispatch models consider all generating units to be always online and ready to produce, which means that they lack important details about the operation of the generation units (Galiana and Conejo, 2009).

Unit commitment and economic dispatch models (UC/ED models) are an extension of ED models. UC/ED models also determine how the load could be allocated among generators at minimum cost but consider the possibility of starting up and shutting down units over a multiperiod time horizon (Galiana and Conejo, 2009). In other words: they consider whether a unit is committed or not. UC/ED models are mixed-integer linear programming models because it is indicated whether a generation unit is online or offline by adding a binary variable to every generation unit (Van Staveren, 2014). This binary variable is used to add minimal output levels and start-up costs to the generators, which allows UC/ED models to calculate an optimal time schedule for the start-up and shut-down of the generation units (Galiana and Conejo, 2009).

UC/ED models are an improvement to the economic dispatch model because the inclusion of start-up costs might influence the model solutions. When power is demanded for a short time span, small generators with low start-up cost and high variable cost might be favoured over large generators with high start-up costs and low variable cost. Solving UC/ED models is more complex than solving pure ED models, because UC/ED models contain binary variables in addition to the continuous variables. However, UC/ED models are used to take power plant dispatch decisions in the actual power system and these models are therefore closer to the actual practice than pure ED models.

2.3. Flexibility solutions: system benefits

Flexibility in the power system offers the possibility to influence the impacts of variable renewable energy production. There are currently five flexibility solutions, namely demand response, variable renewable energy curtailment, flexible back-up generation, electrical energy storage and interconnection capacity (Verzijlbergh et al., 2014). This section contains more information about the two flexibility solutions that will be considered in this study: large-scale energy storage and cross-border transmission capacity.

2.3.1. System benefits of cross-border transmission grid extensions

Several studies on the system benefits of transmission grid extensions exist, differing in type of model that is used and each with their own strengths and limitations. This section discusses two of these studies and their outcomes in more detail, as these provide relevant insights about the influence of interconnection on the KPIs (Brancucci Martínez-Anido et al., 2013; Fursch et al., 2013).

Fursch et al. (2013) use an investment and dispatch optimisation model with a load flow based grid model in order to quantify the benefits of optimal transmission capacity investments in terms of CO₂ reduction, RES targets and balancing fluctuating RES-E. The model covers 27 European countries together with North Africa to import solar energy from and is used to compare the benefits of grid extensions to other options such as curtailment or larger use of storage capacity.

Fursch et al. (2013) found that a large transmission capacity can be a cost-efficient option for the increase of variable renewable generation for two reasons. Firstly, a stronger transmission network allows use of favourable sites for renewable energy generation, as long as these sites are not too remotely located from big consumption areas for it being cost-efficient. In such remote locations, the costs do not outweigh the benefits. Secondly, the transmission grid can smooth production fluctuations by transferring renewable generation that exceeds the energy demand in one area to areas where more energy is needed. By spatially shifting energy it can deal with seasonal fluctuations caused by renewable generation (Fursch et al., 2013).

Furthermore, much grid enforcement can be especially needed in European countries with a large amount of wind energy in their power system (Fursch et al., 2013). Storage was only used in periods with the highest RES in-feed. Impeding optimal grid extensions leads to more storage investments in the model. However, it should be noted that the model used by (Fursch et al., 2013) applied a typical day instead of 8760h and neglects the stochastic nature of RES, which may lead to an underestimation of both system costs and the need for flexible generation due to RES in-feed. Moreover, the use of an optimisation model may also lead to an underestimation of the results.

The cost of new cross-border transmission capacity influences the import and export flows and thus the demand for interconnection (Fursch et al., 2013). Low-cost interconnections are built more, leading to a larger capacity and therefore influences the import and export between countries (Fursch et al., 2013). For example, a larger interconnection capacity between the Netherlands and France leads to a larger primary export of electricity from Dutch wind generation to France than to Germany.

Apart from the effect of the cost of interconnection on cross-border flows, the demand for cross-border transmission capacity is also influenced by the price differences between countries. Cross-border transmission capacity is in essence a facilitator of electricity flows based on electricity price differences between countries. Transmission of low-priced electricity to countries with higher electricity prices will prevent expensive generation from being committed, lowering the electricity price compared to situations when these expensive units have to generate. Brancucci Martínez-Anido et al. (2013) state that a larger number of hours in which natural gas units are marginal can lead to smaller price differences between countries and thus a lower demand for interconnection.

The optimisation study by Brancucci Martínez-Anido et al. (2013) considers 8760 h in order to capture the fluctuation nature of RES. This study uses a cost-minimising dispatch model to model 32 European countries with an hourly resolution for a given year. The purpose of their study is to compare different scenarios of electricity generation and cross-border transmission capacity in order to analyse the impact of cross-border transmission capacity on CO₂ emissions, dispatch costs, curtailment needs

and hydro storage utilisation (Brancucci Martínez-Anido et al., 2013). The study thus focuses on the effects of an increasing cross-border transmission capacity in the European system.

The results in (Brancucci Martínez-Anido et al., 2013) are dependent on the ratio between demand, generation and cross-border transmission capacity. The electricity demand and the generation by variable RES define the residual demand, which is a measure for the flexibility requirements in a system. The residual demand influences the demand for cross-border transmission capacity and the ratio between residual demand and available cross-border transmission capacity influences the effects on the output variables.

Brancucci Martínez-Anido et al. (2013) define the annual dispatch costs as the sum of generation dispatch costs and cross-border transmission costs. It was found that, given the same scenarios for generation and demand, an increase of cross-border transmission capacity can reduce annual dispatch costs. This reduction is due to the improved connection for electricity transmission from countries with low-cost marginal generation to countries with high-cost marginal generation.

However, varying the generation or demand scenarios influenced the benefits of additional cross-border transmission capacity. Brancucci Martínez-Anido et al. (2013) found in their sensitivity analysis that the extent to which additional cross-border transmission capacity can be beneficial with respect to reducing the annual dispatch costs depends on the demand growth and the share of variable RES.

Additional cross-border transmission capacity can lead to a larger reduction in annual dispatch costs when the share of variable RES is larger. On the contrary, additional cross-border transmission capacity can lead to a smaller reduction in annual dispatch costs when demand grows faster. A larger demand growth leads to more marginal hours for back-up generation, which are typically served with natural gas units (Brancucci Martínez-Anido et al., 2013). This can lead to a smaller reduction in annual dispatch costs because natural gas units have high variable generation costs. Additionally, it was found that a larger number of hours in which natural gas units are marginal can imply smaller price differences between countries and thus a lower demand for interconnection.

With regard to curtailment needs, Brancucci Martínez-Anido et al. (2013) conclude that RES curtailment needs are generally not caused by interconnector capacity constraints, given their generation and demand data for 2010 and 2025. RES curtailment needs are smaller for larger interconnection capacity, but the effect is almost negligible between scenarios.

However, as with dispatch costs, curtailment needs can be sensitive to electricity demand growth and the share of RES in a system (Brancucci Martínez-Anido et al., 2013). Additional cross-border transmission capacity can reduce the need to curtail RES more in case of low electricity demand, as then there are more hours of RES overgeneration in a country. Comparably, a higher electricity demand leads to fewer moments with RES surpluses and consequently to less curtailment needs. A larger interconnection capacity can reduce these curtailment needs even more (Brancucci Martínez-Anido et al., 2013).

RES curtailment increased for a larger share of RES, regardless of additional interconnection capacity (Brancucci Martínez-Anido et al., 2013). Nevertheless, curtailment increases less strongly when there is extra cross-border transmission capacity as compared to the scenario without extra capacity.

2.3.2. Energy storage

Energy storage facilities are net consumers of energy as losses occur during the conversion processes for storing energy (Lund et al., 2015). Nonetheless, storage facilities can generate revenue through energy arbitrage. Energy arbitrage is taking advantage of the electricity price differences between for example day and night or weekday and weekend prices.

Energy storage technologies can be characterised by their energy storage and power capacities. Storage with a high power capacity can respond to supply-demand mismatches of a higher magnitude, while a larger energy storage capacity allows the storage to respond to longer mismatches (Lund et al., 2015). The combination of energy storage and power capacities are thus paramount in selecting a storage technology.

Short term storage can store energy for a period of seconds up to several days. In the very short duration, that is, milliseconds to five minutes, energy storage is used for power quality and regulation. Examples of short term storage technologies are flywheels, super capacitors and superconducting magnets (Lund et al., 2015). Energy storage storing energy for periods of five minutes to one hour are generally used for spinning reserve services and require a short response time and several hours of use. Demand side management, flow batteries and pumped hydro energy storage are suitable technologies for this type of energy storage. Energy storage for intermediate duration, which is for one hour to three days, is used for various applications such as matching power demand and supply and managing mispredictions in the wind and solar output. Examples of technologies that can be used for this are compressed air energy storage, demand side management and pumped hydro energy storage (Lund et al., 2015).

Long-term seasonal storage can hold the energy for several days up to several months. Seasonal variations of renewable energy require much larger quantities of energy that have to be stored over longer periods (O. Converse, 2012). Flow battery storage and Compressed Air Energy Storage can reach large storage capacities but can store this energy only for multiple hours up to days. Currently, two possibilities for seasonal storage can be identified: pumped hydro storage and hydrogen-based energy storage.

The pumped hydro storage capacity in Northwest Europe is limited due to geographical circumstances and will therefore not be sufficient to reach the long-term flexibility needs in the North Sea region. Moreover, the Netherlands in particular is very unsuitable for pumped hydro storage. It is thus needed to investigate hydrogen-based storage as other seasonal storage option.

In some literature the term Power to Gas is used related to hydrogen-based storage and definitions thereof differ. Some state that Power to Gas is the conversion of power to hydrogen with a subsequent step of converting the hydrogen into methane, while others consider the hydrogen to be directly injected in the natural gas grid or in a hydrogen storage without first converting the hydrogen into methane. This thesis looks at the last option, namely injecting hydrogen directly into the natural gas system or storing it in a hydrogen storage without conversion into methane. Therefore, the term hydrogen-based storage will be used: converting surplus electricity into hydrogen and reconverting this into electricity when there is a shortage.

Economic viability of hydrogen-based storage

Hydrogen storage is based on electricity conversion, which potentially has more advantages than solely electricity storage. With hydrogen it is possible to move the energy as a mixed gas to locations where the gas can generate heat or electricity more effectively (Van Lanen et al., 2016). Moreover, hydrogen is used in industry for semiconductors and as a supplement to petrol for instance. Hydrogen storage has a low round-trip efficiency as compared to other storage technologies but it is currently the only storage option with significantly large long-term capacities (Thema et al., 2016). Sizing of the electrolyser capacity and energy storage is important in order to obtain long-term storage behaviour (Bødal and Korpås, 2017).

Currently, Power to Gas investment costs are very high and it is not yet viable on the large scale. However, it is expected that the investment costs will fall with the amount and scale of new built facilities (Thema et al., 2016). Thema et al. (2016) researched a range of installed Power to Gas capacity in a German 100 % renewable power system until 2050 with two scenarios: one with and one without additional options for short-term flexibility. The study states that costs development in the future will mainly fall because of improvement in efficiency, learning effects and research and development for market introduction focusing on new and cost-cutting progress. It is expected that the investment costs for Power to Gas with hydrogen production will even out around 500 €/kW, based on current investment costs of 1000-3000 €/kW for Power to Gas with hydrogen production and a realistic decreasing trend of 13 % per doubling of the installed Power to Gas capacity (Thema et al., 2016).

Van Lanen et al. (2016) state that return on investment could already be achieved with the operating cost of electricity and the sale of hydrogen, depending on how the hydrogen price is defined. Van Lanen et al. (2016) researched the market mechanisms in a hydrogen based storage facility in Ontario between 2011 and 2013 to determine the viability and profitability of such system. They simulated four different

plant capacities in two different scenarios, namely low price hydrogen production and export reduction. The feasibility of Power to Gas with hydrogen storage in this study is influenced by how the definition of the hydrogen price. Van Lanen et al. (2016) used the equivalent price of industrial hydrogen (made by SMR), ethanol or natural gas to define the hydrogen price in their analysis, leading to different revenue streams for the facility. Using the natural gas price for selling hydrogen was found to be unfeasible, but comparing the hydrogen from electrolysis with hydrogen from SMR or renewable ethanol gave viable results. However, this is only true when the facilities have a high operating capacity and they are not only used to reduce energy exports.

System effects of energy storage

Research on the system benefits of energy storage differs for example in technologies that are covered and the type of model that is used. Each of these studies has its own strengths and weaknesses. This section discusses the findings of two extensive literature reviews on the system benefits of flexibility measures in general and studies on energy storage and hydrogen-based energy storage in particular.

The use of storage can potentially lead to lower system costs, according to the literature review by Blanco and Faaij (2018). They identified four elements that can lead to cost savings due to storage affecting either electricity price or investment cost, namely lower curtailment, lower fuel costs, lower generation investment and lower network investment.

Energy storage can lower the need for curtailment because it allows storing energy at moments with low electricity prices due to a power surplus and a low demand (Blanco and Faaij, 2018). This temporal displacement makes it possible to use energy later to displace conventional back-up generation. This increases the share of variable renewable energy generation in the power system and reduces the energy wasted.

Energy storage can lower the fuel costs as it absorbs the temporal variability of renewables. This allows baseload power production to continue operation at a higher efficiency during periods of low demand (Blanco and Faaij, 2018; Lund et al., 2015). Moreover, this peak absorption by storage reduces the number of times that the output of conventional generators has to be changed.

Storage can as well reduce the fuel consumption needed for balancing purposes, which can imply lower dispatch costs. In some cases, storage provides short-term balancing services to the power grid which are normally provided by flexible units. These flexible units generally have low investment costs and high marginal costs, of which fuel consumption constitutes the largest part. In most countries these flexible units are gas turbines, although some countries use oil plants for this purpose.

Besides reducing curtailment needs and fuel costs, storage can reduce the generation and grid investment costs in the power system (Blanco and Faaij, 2018). The balancing function of storage can lead to fewer generation investments because the required backup and balancing capacity needs are smaller. The reduction in network investments results from storing energy during low load hours, thereby decreasing grid congestion at times of peak demand and stabilising the load of the network.

In addition, storage could contribute to a cost reduction because it can increase the economic efficiency of the power system (Blanco and Faaij, 2018; Lund et al., 2015). Energy storage can store electricity when prices are low and discharge this electricity when prices are high. In a future power system, it can be assumed that low electricity prices are caused by renewables and high electricity prices by back-up generation. However, it depends on the price difference and investment and operational cost of storage whether the savings are large enough to offset the cost and thus lead to an overall cost reduction (Blanco and Faaij, 2018).

However, these system benefits of storage will most likely not be achieved by one technology alone, as they cover a wide range of storage sizes, time frames and time responses ((Blanco and Faaij, 2018)). Regarding hydrogen storage in particular, studies found that its application can lower the total power system costs, reduce CO₂ emissions and curtailment needs and allows for a larger share of RES in the system. The effect of hydrogen storage on dispatch costs was not found in literature.

Thema et al. (2016) concluded that the total cost of a power system is significantly lower with Power to Gas and hydrogen storage than without. The study shows that in the long run Power to Gas will have

a cost-efficient effect on the energy transition in the power system as compared to the system without Power to Gas, even though the grid is expanded according to schedule and short-term storage options are present. In the short run till 2020, the system costs will decrease in a system with and without Power to Gas because of more electricity generation by renewables, which replace expensive production from gas plants. Between 2020 and 2035, the system with Power to Gas has higher costs than the system without due to the construction of the Power to Gas storage infrastructure.

From 2035 on, the long term effect of Power to Gas becomes visible because the use of electricity surpluses overcompensates the investment costs of the facilities and in 2050 an annual saving of up to 18 billion euro is reached (Thema et al., 2016). This contrasts the system without Power to Gas, where costs rise due to increasing expenditures for remunerated curtailment and residual gaps have to be supplied by expensive gas power. Moreover, in 2050 a share of only 86 % of renewables is reached in a system without Power to Gas whereas the system can reach full renewable supply when Power to Gas is present.

2.3.3. Combined system effects of storage and transmission capacity

The interaction between energy storage and transmission capacity in a system with a large share of renewable energy sources has been widely examined. Studies differ in terms of their targeted RES penetration level, energy system, generation mix, demand patterns, stochasticity, projection year, type of storage and how precisely this storage is modelled. Still, general conclusions about the interaction between both technologies can be drawn from such studies.

Studies show that energy storage and transmission capacity can substitute and complement each other to some degree (Brancucci Martínez-Anido and De Vries, 2013; Steinke et al., 2013). Complementarity is defined as the situation in which one variable can increase the demand for another one. This is different from substitution, which means that one variable can reduce the demand for another one (Brancucci Martínez-Anido and De Vries, 2013).

Steinke et al. (2013) researched the interdependence between transmission and either pumped water, battery or hydrogen storage by varying the capacities of both technologies over a wide range of values. A European power system with an optimal RES mix of 65% wind and 35% solar PV in the average yearly energy production based on the study by Heide et al. (2010) is considered. Biomass is considered the dominant renewable back-up source that can be dispatched on a large scale, but it has limited potential. Steinke et al. (2013) conclude that this biomass energy potential can only be nearly reached if both transmission as well as storage capacity are extended significantly compared to today's level. However, the study considers only one storage technology at a time, which might overestimate the back-up energy demand as different storage technologies might interact and can account for different storage needs. On the contrary, the required back-up energy could also be underestimated because the study considers a seasonal optimal mix of wind and solar PV.

Nevertheless, it could be concluded from Steinke et al. (2013) that a 100% renewable energy system can only be achieved with energy storage and transmission capacity expansion. Haller et al. (2012) arrive at a similar conclusion with a conceptual model that integrates long term investments and short term power system operation in Europe into one optimisation framework.

Additionally, Haller et al. (2012) show that investments in storage and investments in transmission capacity can act as complements. Higher storage investments can occur when the option to invest in transmission capacity is available and conversely, more storage investments can lead to higher investments in transmission capacity. Both technologies together can lead to the highest cost savings in the system. However, fluctuating patterns of supply and demand are not taken into account in this analysis and this may influence the robustness of the result.

The interaction between pumped hydro storage and cross-border transmission capacity is specifically researched by Brancucci Martínez-Anido and De Vries (2013), using a minimum cost dispatch model of Europe with a one hour time-step. The capacities in this model are varied exogenously in order to see the impacts on the European power system as well as the impacts on each other.

Pumped hydro storage and cross-border transmission capacity are substitutes when it comes to reducing annual dispatch costs, CO₂ emissions and the need for renewable energy curtailment (Brancucci Martínez-Anido and De Vries, 2013). RES curtailment is decreasing in some European countries because of an increase in interconnection capacity, while in other European countries RES curtailment is decreasing because of an increase in hydro pumping capacity. However, using both technologies in combination has an even stronger positive effect on these system variables. Energy storage and transmission capacity are shown to have synergistic effects in a high RES system, which means that combining both technologies leads to greater system benefit than using them separately (Brancucci Martínez-Anido and De Vries, 2013).

Solomon et al. (2014) also show that the use of energy storage alongside transmission capacity expansion can allow for lower energy curtailment and a larger penetration level of renewable energy sources when compared to using only one technology to match supply and demand patterns. Solomon et al. (2014) performed an hourly simulation of the power system of the state of California, including a very high penetration of renewable energy generation. The solar and wind energy technologies are distributed throughout California and interconnected by the grid.

In (Solomon et al., 2014) using only the existing transmission grid capacity to match supply and demand patterns allowed for the RES penetration of 80 % but accounted for an energy curtailment worth 40% of the annual demand. Expanding the transmission grid did not lower this energy loss and had a limited benefit in further penetration. By contrast, the use of both storage and the existing transmission capacity resulted in only a 15% energy curtailment.

Moreover, it was found that both technologies depend on the available capacity of each (Brancucci Martínez-Anido and De Vries, 2013). Pumped hydro storage utilisation increases the need for cross-border transmission capacity, whereas cross-border transmission decreases the need for hydro pumping. In other words, pumped hydro storage complements cross-border transmission capacity while, on the other hand, the latter substitutes the first.

Bogdanov and Breyer (2016) come to a similar but more general conclusion: transmission capacity reduces the need for a range of energy storage options and for short term storage in particular. The study looks at battery storage, pumped hydro storage, thermal energy storage and the power-to-gas technology and covers five scenarios for a 100% renewable North-East Asian power system, where renewables supply enough energy to cover the electricity and gas demands that are estimated for the year 2030. Lower total energy system costs were reached by increasing the transmission capacities and reducing the overall storage capacities (Bogdanov and Breyer, 2016).

The degree of interconnection between European countries thus influences the corresponding storage needs in a high RES system (Brancucci Martínez-Anido, 2013). Within Europe, transmission capacity expansion implies that there is more cross-border transmission capacity as countries are close to each other and not self-sufficient. Storage needs will be almost doubled and they will even rise steeply for more than 70% renewable energy when only national grids are considered. A European energy system with 100 % RES is even found to be unfeasible without cross-border transmission capacity, considering that the potential of biomass in Europe is limited.

2.4. Modelling storage

Harris et al. (2012) recommend using a time step of at least 5 minutes long to model seasonal storage commitment decisions in a unit commitment model. In their study, they use a time step of 15 minutes, but most studies use a 1 hour time step (Brouwer et al., 2014; Fursch et al., 2013). A sufficiently small time step is needed to avoid that the model gives a result that is implied by the selected time scale.

Storage can be modelled by its operation constraints, namely charge and discharge rates [MW], variable marginal costs [€/ MWh], total energy capacity [MWh] and charging and discharging efficiencies (Harris et al., 2012). Furthermore, it is reasonable to assume the state of charge of the storage unit to be cyclic when a full year is modelled (Harris et al., 2012; Schlachtberger et al., 2017). This allows for an efficient use of the storage unit at the beginning of the year and captures the yearly periodicity of demand and seasonal generation.

Capital costs of a storage unit should not typically be included in the bids in an electricity market. For

that reason, capital costs should be evaluated separately and compared to the dispatch cost reduction that follows from the model (Harris et al., 2012). In this way, the results also stay instructive in case of changing capital costs due to economies of scale.

Furthermore, storage should preferably be modelled as price maker. Storage benefits can be artificially raised to a large extent when storage is modelled as price taker, because the effects of price leveling of energy storage for arbitrage are then neglected (Harris et al., 2012).

2.5. Conclusions

This chapter discussed the impacts of variable RES on the power system and this led to a set of system KPIs for this study: annual and average dispatch costs, curtailment needs and total system costs. Moreover, it was discussed what aspects are relevant for modelling flexibility. Different methodologies were reviewed in order to see why Powerflex, a unit commitment and economic dispatch model, would be suitable for this study. After that, insights were given into the system effects of grid extensions and seasonal storage and their effects on another. Hydrogen based storage was found to be the most viable option in the Netherlands in the future and therefore more information was given on the economic viability and system effects of this type of storage in particular. The chapter concludes with a section on how storage could be modelled, which serves as input for the chapter about conceptualisation of the storage module.

3

Powerflex

This chapter contains a description of Powerflex, which is the model that is extended for the purpose of this study. After a general description of the scope and the data of the model, the chapter will zoom in on the modelling methodology that is used in Powerflex: unit commitment and economic dispatch. The main goal of Powerflex is to model the Dutch day-ahead market in a Northwest European context, including the flexibility requirements and flexibility supply under different future scenarios. The mathematical formulation will be given and the solution methods will be elaborated on, after which the modelling approach and its assumptions and limitations will be discussed. To research the effects of cross-border transmission capacity and seasonal storage on the future Dutch power system, Powerflex will have to be extended with an electricity storage module and the location of this module in the model will be specified.

3.1. General description

Powerflex models the Dutch day-ahead market in a Northwest European context according to price-based market coupling. The model simulates the flexibility demand and the flexibility supply within the electricity markets in detail, including interaction with neighbouring countries and cross-border transmission constraints. Market coupling means that one electricity market with one price is created for all the countries involved, unless the transmission capacity between the countries is insufficient.

The Netherlands, Germany, Belgium and France are within the geographical scope of the model. However, for this research only the Netherlands and Germany have been included; adding more countries would make the analysis unnecessarily more complex and time consuming as more data would be needed.

Each country is modelled as a single node with corresponding deterministic input data, namely fuel costs, CO₂ prices, conventional plant characteristics and hourly time series with renewable generation, hydro storage and demand profiles. The behaviour of German hydro plants has been approximated by combining the behaviour of a gas turbine and an electric boiler. Figure 3.1 gives an overview of the input data per country. The model considers a fixed maximum capacity of each generator and does thus not contain an investment module.

Powerflex is a short-term model focusing on power plant scheduling for every hour of one given year. Balancing demand and supply for each hour in each country results in production levels for each unit and a system marginal cost in each country. The electricity prices between the markets are balanced by cross-border flows. This is shown in Figure 3.2: country A has a low electricity price in a certain hour, whereas there is a high electricity price in country B. Electricity will flow from country A to country B, thereby increasing the demand in country A and increasing the supply in country B. This leads to new prices in both countries, until either prices become equal or maximum interconnection capacity is reached. Additional input data is thus the cross-border transmission capacity between two countries.

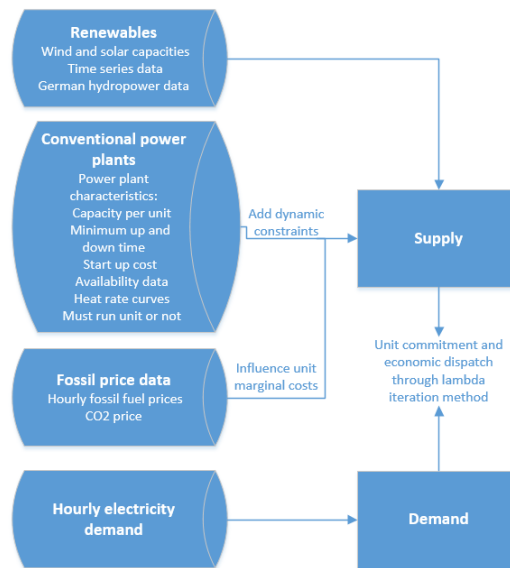


Figure 3.1: Overview of input data per country. Cross-border transmission capacity between two countries is an input as well.

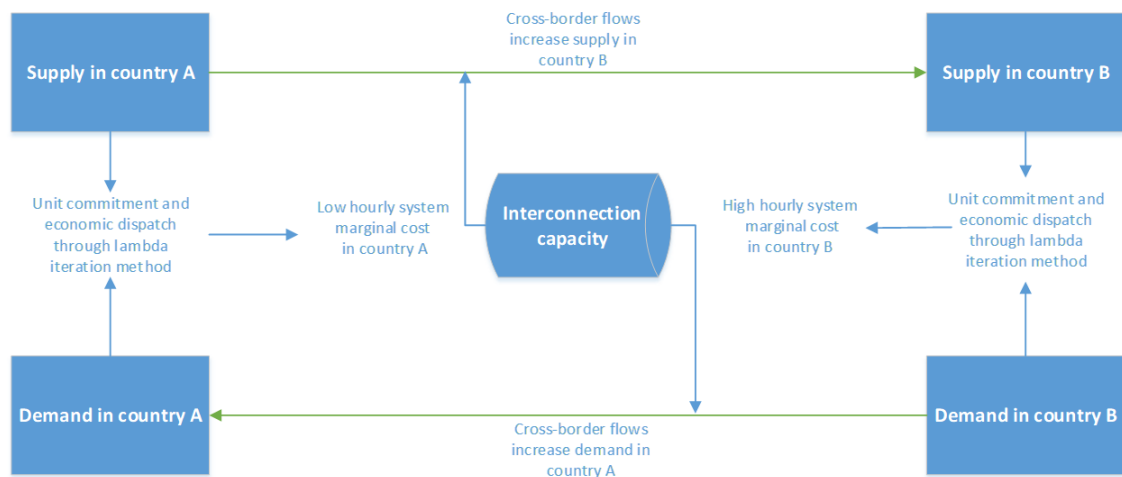


Figure 3.2: Visualisation of cross-border flow between two countries.

3.2. Unit commitment and economic dispatch

Powerflex is an unit commitment and economic dispatch model (UCED model), optimising the power system operation to supply the residual demand at all times, assuming solar and wind power production are always dispatched. The model runs iterations to find the hourly balance between supply and demand in any given country resulting in the hourly electricity price in that country. The model plans the production outputs of a system of generation units in order to fulfil the expected electricity demand at minimal cost, taking into account the technical constraints of the system. For this it determines the optimal production output of each production facility in the generation mix (economic dispatch) and the optimal commitment of each production facility (unit commitment). In every iteration of the model, the two sub-problems are addressed.

The optimal production of each individual unit is thus dependent on the total production of all units that are needed to supply the hourly demand in a country. Each individual unit in the model has its own marginal costs and is part of the merit order, which is a ranking of production units according to the increasing marginal costs. The merit order forms the supply curve in any country. Matching demand and supply in each hour results in the system marginal costs for each hour and will thus specify the optimal production level per unit. The electricity price in the day-ahead market should be equal or higher than these system marginal costs to obtain profitable production.

The economic dispatch problem is a sub-problem of the more complex unit commitment problem. According to the economic dispatch problem, a generation unit will produce when its marginal costs are lower than the system marginal cost. However, the unit commitment decision is needed to define which generators are connected to the system in order to provide the load at minimum system marginal cost.

3.3. Mathematical formulation

In an optimisation model an objective function is minimised or maximised by changing the variables in the energy system. These energy system's variables are limited by a set of constraints such as demand profiles, technical limitations and other characteristics about the operation of the power system (Götz et al., 2012).

The objective function is subject to two types of constraints: system constraints and dynamic constraints. System constraints have to be satisfied for every hour t of the year. These problems are separable in sub-problems for every hour. An example of a system constraint is that the load should be satisfied in every hour of the year. Conversely, dynamic constraints contain a time-dependency and are separable in production units but not in time steps. For example, a minimum up-time constraint requires that a power plant starting up in hour t cannot shut down before hour $t + \text{its minimum up-time}$.

3.3.1. Objective function

The objective of Powerflex is to minimise the total system cost. This leads to the objective function in equation 3.1, with t a time step of one hour, T the total number of hours, n a single generator and N the total number of generators in the system.

$$\text{Minimise } C^{\text{total}} = \sum_{t \in T} \sum_{n \in N} (C^{\text{fuel}}(P_{n,t}) + C_{n,t}^{\text{startup}} + C_{n,t}^{\text{maint}}) u_{n,t} \quad (3.1)$$

In which $C^{\text{fuel}}(P_{n,t})$ is the fuel costs as a function of the production level, $C_{n,t}^{\text{maint}}$ is the fixed maintenance cost and $C_{n,t}^{\text{startup}}$ represents the start-up cost. Committing a thermal unit implies start-up cost because of the fuel consumption during the time the unit is being turned on. Turning a thermal unit on means: bringing the unit up to speed, synchronising it to the system and eventually connecting it so that it can supply power to the network. The fuel consumption during start-up does not result in generated output and is thus an extra cost when it is decided to commit a unit.

Furthermore, $u_{n,t}$ represents the unit commitment decision and this variable can be either 0 or 1, meaning that a unit is turned off or turned on respectively (see equation 3.2).

$$u_{n,t} \in \{0, 1\} \quad (3.2)$$

3.3.2. System constraints

The objective function is subject to two system constraints, namely the load constraint and the cross-border transmission capacity constraint. The load constraint means that the sum of the powers generated by the committed units must satisfy the demand P_t^{load} in every hour t , as stated in equation 3.3.

$$\sum_{n \in N} P_{n,t} u_{n,t} = P_t^{load} \quad \forall t \quad (3.3)$$

The cross-border transmission capacity constraint ensures that the cross-border flow does not exceed the maximum interconnection capacity NTC, see equation 3.4. The cross-border flow of the export country to the import country is represented by T_t^{export} .

$$T_t^{export} \leq NTC \quad \forall t \quad (3.4)$$

3.3.3. Dynamic constraints

The objective function is also subject to several dynamic constraints, which describe the technical limitations of the generating facilities.

The capacity of a generating unit is limited to its minimum and maximum capacity, as shown in equation 3.5.

$$P_n^{min} \leq P_{n,t} \leq P_n^{max} \quad (3.5)$$

Furthermore, a thermal unit can undergo only gradual temperature changes, which results in a minimum time that the unit should be on and a minimum time the unit should be turned off before it can be recommitted. These time periods are called the minimum up-time and minimum down-time respectively and these constraints are shown in 3.6 and 3.7, in which τ represents the time range for which the constraint should be satisfied. For example, the inequality in 3.6 should apply to τ with time step $t+1$ until time step $t + t^{up} - 1$, unless the end of the planning horizon T is reached before that time.

$$u_{n,t} - u_{n,t-1} \leq u_{n,\tau} \quad \text{with} \quad \tau = t+1, t+2, \dots, \min(t + t^{up}, T) \quad (3.6)$$

$$u_{n,t} - u_{n,t-1} \geq 1 - u_{n,\tau} \quad \text{with} \quad \tau = t+1, t+2, \dots, \min(t + t^{down}, T) \quad (3.7)$$

The thermal units also undergo maintenance or unscheduled outages, which is also taken into account in the unit commitment decision. Moreover, some units are must-run units, which means that they should always be committed to the system. Constraint 3.8 applies to these must-run units.

$$u_{n,t} = 1 \quad \forall t \quad (3.8)$$

3.3.4. Solution methods

This paragraph elaborates on the solution methods in Powerflex, namely the lambda iteration method and the dynamic programming procedure. In Powerflex the economic dispatch and unit commitment optimisation is implemented in an iterative process, which is known as the lambda iteration method. Dynamic programming happens in a sub-step of the lambda iteration method and is used to calculate whether a unit is committed.

Lambda iteration method

The lambda iteration method is an iterative procedure that is used to calculate the electricity price lambda for every hour of the year. The lambda should be set in such way that the objective function is minimised and both the system constraints and dynamic constraints are satisfied in each hour. The dynamic constraints are satisfied when each power unit can commit and produce within its own operational limits at minimal cost. The system constraints are satisfied when the electricity demand can be supplied and the cross-border transmission capacity is not exceeded.

Lambda is a vector that contains the electricity price in every hour of the year. Per iteration, it is calculated for every value within the vector lambda how much the electricity price in each hour deviates from the optimal solution in that hour. The electricity price is decreased in hours with overproduction and increased in hours of scarcity. This adjustment of the electricity price converges towards a solution to the optimisation problem.

The lambda iteration method consists of a number of steps, based on Lagrange relaxation. Lagrange relaxation is a method to decouple the objective function into two separate sub-problems, each subject to either the dynamic constraints or the system constraints. In this way, unit-based coupling and system-based coupling can be calculated separately. This makes it possible to evaluate the unit commitment $U_{n,t}$ and economic dispatch problem $P_{n,t}$ per unit first, after which it is checked whether the load can be supplied by the production of all committed units together.

The model runs several iterations of the lambda iteration method in order to optimise the commitment decision of the N units and their corresponding production levels. Adjustments of lambda lead to changes in the optimal commitment decision per unit. The result is a set of commitment decisions and production levels per unit, that together can supply the load in every hour of the year at minimum system marginal cost. Moreover, the cross-border flows should not exceed the maximum cross-border transmission capacity.

Figure 3.3 shows the flow chart of the lambda iteration method. The lambda iteration method firstly initialises by using the input data to find initial production levels and commitment decisions corresponding to an initially estimated system marginal cost λ .

After this initialisation, the unit commitment variable U and production level P per unit are calculated. The unit commitment procedure per unit is evaluated through dynamic programming and will be elaborated on in Paragraph 3.3.4. The economic dispatch procedure evaluates the production levels of the individual units at the system marginal cost.

Figure 3.4 shows how the production level P per unit depends on the system marginal cost and the marginal cost curve per committed generation unit. The marginal costs of production of a generation facility are the production costs of producing one more unit of electricity in €/MW. The marginal costs of production usually increase linearly with increasing production and are determined by operation and maintenance costs, CO2 price and fuel prices, the latter of which forms the largest component. The marginal costs of a generation unit should be less than or equal to the system marginal cost in hour t, which results in a certain production level.

In the next step, it is checked whether the load P_{load} can be satisfied given the sum of all production levels P_i of the individual units while minimising the system marginal cost. When there is overproduction or underproduction, the load constraint equation 3.3 will not result in zero but in a certain difference ϵ .

In the model, the absolute value of this difference is required to meet a tolerance value. When the tolerance value is not met, this thus means that the overproduction or underproduction of all units together is too large and that the load cannot be adequately supplied with these units and corresponding production levels.

If production in a specific hour is too low, the system marginal cost lambda is raised. If production in a specific hour is too high, the system marginal cost lambda is lowered somewhat. After adjustment of the lambdas for each hour, in order to improve the match between supply and demand, the commitment and production level per unit is evaluated again.

In every iteration, the system marginal cost will be adjusted and minimised and as such step-by-step approximating the optimal system marginal cost profile until the load can be adequately supplied by the dispatched units or until the final iteration is reached.

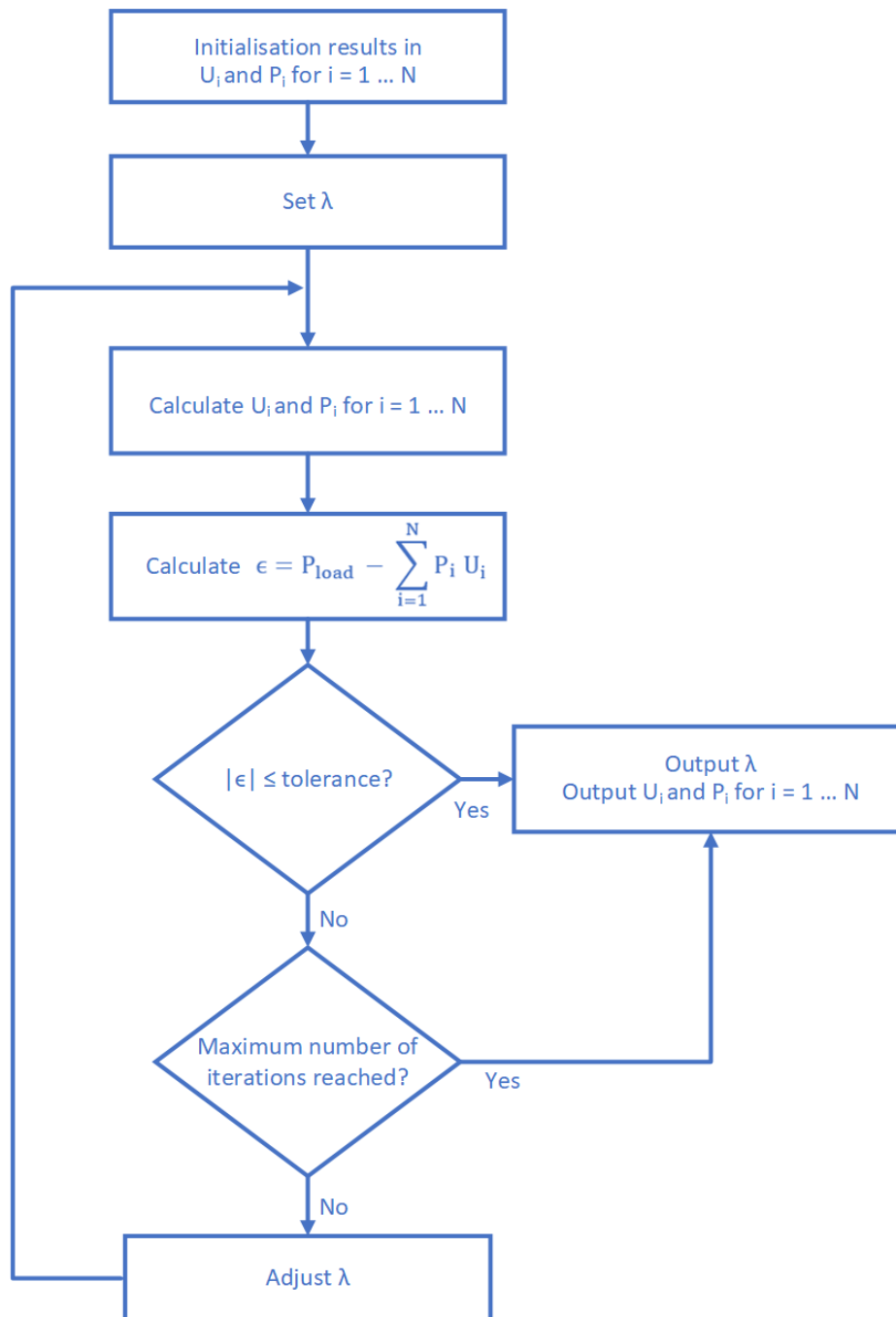


Figure 3.3: Flow chart of the lambda iteration method

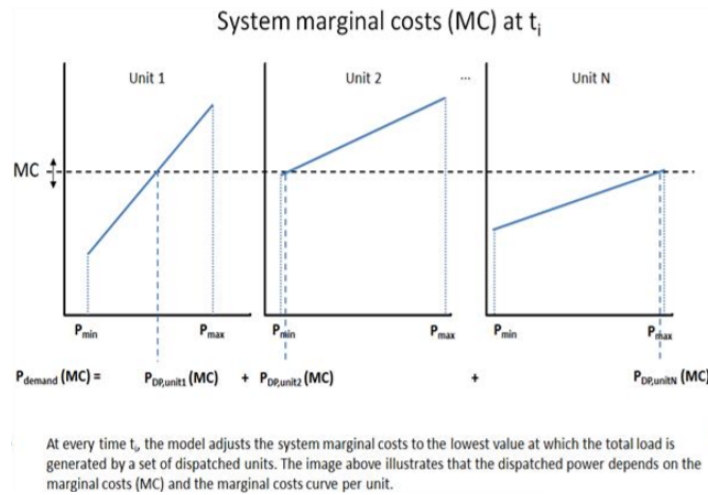


Figure 3.4: Illustration of the calculation of production level per unit, given a certain system marginal cost. Adapted from Hers et al. (2016)

Dynamic programming

The unit commitment problem for each individual unit, as part of the lambda iteration method, is solved with a dynamic programming procedure. Dynamic programming is a technique to find an optimal sequence of decisions over the time horizon of the model. A sequence is optimal in Powerflex when it is the minimum cost route, which is also called the optimal policy. The optimal policy is found by choosing a route that consists of optimal sub-policies. This is the theorem of optimality; a policy is optimal if it consists of only optimal sub-policies.

Sub-policies are chosen at decision moments, which are also called stages. In Powerflex a stage represents a simulation hour and at each stage it is evaluated whether the unit is committed (1) or not (0). The dynamic programming procedure results in an optimal policy consisting of commitment decisions in each hour of the simulated year, taking into account the previously described dynamic constraints.

A unit is allowed to commit when its unit-specific dynamic constraints are fulfilled. These dynamic constraints influence the commitment decision and can sometimes lead to the unit being committed while this would normally not be the optimal decision. This is illustrated in Figure 3.5, where the minimum up-time constraint imposes the unit to be committed in hours where its marginal costs are higher than the system marginal costs. Such situations can lead to an adjustment of the system marginal costs in the lambda iteration method.

Generally, a unit will be committed when the marginal cost of the unit is lower than the system marginal cost. Moreover, the start-up costs that are incurred when a unit commits should be regained during its committed period. Each commitment decision has thus implications for fuel costs, system marginal costs or start-up costs that are either avoided or incurred. These implications should be taken into account in defining which generation units can provide the load at minimum system marginal cost.

3.4. Discussion of modelling approach

Power system models can be seen as an approximation of reality. A single model cannot capture the power system in its entirety because of the power system being very complex. It is computationally difficult to model all interactions and effects and required data are often unavailable. Choices have to be made on how to represent the power system and models are therefore based on assumptions. This section elaborates on the modelling approach and some assumptions in Powerflex, based on the section about model classification in Chapter 2.

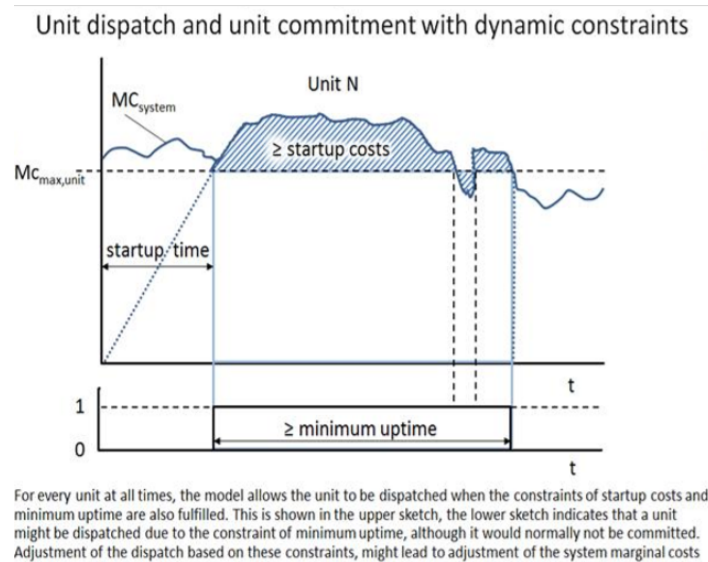


Figure 3.5: Illustration of the relation between the dynamic constraints and the unit commitment decision. Adapted from Hers et al. (2016)

Powerflex is an optimisation model which minimises the total system costs from a central decision maker's perspective. Market failures that occur in the real world are not taken into account in Powerflex. This means that an efficient market is modelled with perfect foresight and knowledge and without monopolies or oligopolies that influence the decision making.

However, in the real world, decision making happens decentralised as every plant operator exhibits its own price-dependent human behaviour. The decisions are made by individual actors that are mainly focused on increasing their profits, either in a risk averse, a risk neutral or a risk seeking manner. Human behaviour can have a substantial influence on the electricity system's performance, which causes differences between the results of the model and real world behaviour. For example, in some situations an operator can decide to operate its own assets instead of purchasing electricity externally as this leads to the lowest personal costs, even though this is not the least-cost solution for the system as a whole.

Powerflex is a deterministic model: it assumes perfect foresight with expected values for all parameters, which means that no uncertainty is assumed in the model. In actual fact, these parameters are subject to unpredictable influences such as climate or weather circumstances and fuel prices. Such uncertain parameters can have a large influence on the operation of the electricity system and can lead to a sub-optimal dispatch. In this thesis, a sensitivity analysis is performed to gain insight into the effects of these uncertain parameters on the key performance indicators. This allows for a first understanding of the importance of these uncertain parameters for the results of the study.

In the actual power system, renewable energy generation is subject to the spatial and temporal correlation of weather and climate circumstances. Powerflex contains hourly time series to model the electricity generation by renewables. The hourly data allows for a detailed representation of short-term hourly and seasonal fluctuations within a year. Hourly temporal detail should be sufficient to model the variability of renewables, according to the literature review by (Brouwer et al., 2014). However, Powerflex does not contain a detailed spatial distribution of renewables as each country in Powerflex is modelled as a single node. The lack of spatial detail might influence the required storage capacity in Powerflex, but more spatial detail has not been included because data with sufficient detail and quality is unavailable.

Powerflex thus contains sufficient hourly detail to model the variability of renewables on the electricity supply side. However, to cope with an increasing share of variable renewables in scenarios of the future, it should be possible to model flexibility options with Powerflex as well. Powerflex has some advantages and disadvantages when it comes to modelling the mix of future flexibility options.

Firstly, the electricity demand in Powerflex is assumed to be inelastic, which means that demand side flexibility is not included. In the actual power system, electricity demand is elastic to a certain extent due to the price responsive behaviour of industry and horticulture and to a lesser extent the behaviour of consumers. Moreover, the electricity demand is expected to be even more elastic in the future because of demand response with electric vehicle charging for instance. However, it is difficult to quantify load shift potentials with the data that are currently available in order to model demand elasticity. The inelastic demand in Powerflex is therefore accepted as a discrepancy between the model and reality which might lead to an overestimation of the flexibility requirements in the model.

Secondly, the two electricity markets in Powerflex are connected by an interconnector. Each hour, power is transferred from the country with low electricity price to the country with high electricity price, taking into account the maximum transmission capacity. The interconnection capacity is modelled with monthly detail, which is sufficiently precise to see the influence of increased or decreased capacity.

Each country is modelled as a single node, which means that national transmission and distribution network constraints are not included in Powerflex. This is also called the copper plate assumption as internal network congestion is omitted. Neglecting the internal transmission and distribution network implies that the interlinkage between network and market operation within a country is not taken into account.

When power can flow unrestrictedly within a country in the model while this is not true in reality, this might lead to a miscalculation in required flexibility. This can lead to an underestimation in system (marginal) costs as for instance dispatch costs might be higher or larger investments in the internal network might be needed.

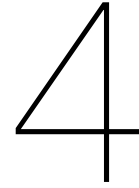
The option to curtail renewable energy supply and to store electricity are flexibility options that are not included in Powerflex. Renewable energy curtailment is performed after each model run by manually finding the hours with negative electricity prices in the results. However, the option to store electricity is needed for the purpose of this study and for this reason an electricity storage module is implemented in Powerflex.

3.5. Electricity storage in Powerflex

The electricity storage module will be implemented as a separate function in the lambda iteration method in Powerflex, which is performed for both countries in the model in order to find a solution to the unit commitment and economic dispatch problem. The lambda iteration method is a suitable location for the storage module because it allows its output to participate in the economic dispatch procedure of the model in order to supply flexibility by levelising the load as either supply or demand. The unit commitment problem of the storage unit will be solved using the dynamic programming procedure, which is also used for the unit commitment procedure of the other units in the model. As a storage unit can act as demand or supply at different levels, its output level can have more options than that of a thermal generator, which can be either on or off. The unit commitment procedure of the storage unit is therefore expanded from a two states problem into an economic-scheduling problem with multiple states, where each state represents different levels of either production or consumption.

3.6. Conclusions

This chapter described the unit commitment and economic dispatch model Powerflex, which main goal is to model the Dutch day-ahead market and its flexibility requirements and flexibility supply when it is connected to the German day-ahead market. A discussion of the modelling approach identifies its strengths but also its major limitation for this study: the lack of an electricity storage as a flexibility option. To research the effects of cross-border transmission capacity and seasonal storage on the future Dutch power system, Powerflex will have to be extended with an electricity storage module. It is most suitable for the module to be implemented as a separate function in the lambda iteration algorithm in Powerflex. The unit commitment and economic dispatch problem of the storage module will be solved by dynamic programming. The next chapter contains the conceptualisation of the electricity storage module.



Conceptualisation and formalisation

Chapter 2 discussed that an energy storage can generally be characterised by its energy capacity, charging and discharging efficiency and charging and discharging capacity. Chapter 3 showed that an energy storage can be included in the lambda iteration method of the Powerflex model, according to the dynamic programming procedure. This chapter discusses the conceptual design of an energy storage module that will be added to the Powerflex model. The storage module has originally been designed to allow for the representation of different storage technologies, as the generic design makes it possible to change the characteristics of the storage. However, the storage module is used as a hydrogen storage for this research and this chapter will therefore discuss the hydrogen storage setup specifically. After describing the desired behaviour of the storage unit and structural assumptions, the chapter will derive a mathematical representation of this and discuss the adjustments to the Powerflex model in order to include the storage module in it.

4.1. Hydrogen storage

Electricity storage can be defined as a three-step process, consisting of a charging step, a discharging step and a storing phase in between, see figure 4.1 (SBC Energy Institute, 2014). When electricity storage charges, it withdraws electricity from the grid and becomes part of demand. Discharging means that the storage unit acts like generation as it re-injects electricity into the grid. The charging and discharging capacity define the rate of energy withdrawal and energy injection respectively. In the storage phase energy is time-shifted from a period with low demand to a period with high demand in order to level the load. The storing phase can be characterised by the energy capacity.

The hydrogen storage is added to the generation portfolio in Powerflex in order allow for the dispatch in a way similar to the dispatch of thermal generators. However, thermal generation units in the generation portfolio of a country can either produce or not produce whereas a storage unit also has the option to be part of the load. This implies that the storage unit will be part of demand when it charges and part of supply when it discharges.

Electricity storage makes use of energy arbitrage, meaning that electricity is purchased and stored during off-peak hours with low electricity prices and sold during peak hours when electricity prices are high. The electricity storage can make profit by making use of the price differences between off-peak and peak hours. Additionally, hydrogen storage is a specific type of electrical energy storage based on conversion of energy into an energy carrier: hydrogen. Apart from charging and discharging energy, hydrogen storage can also sell part of its energy capacity in the hydrogen market. The storage module is modelled assuming perfect foresight: the electricity price and hydrogen price are known for every hour of the year.

The goal in this study is to show the value of this energy arbitrage for the hydrogen storage and for the Dutch power system as a whole. For this reason, the dispatch and thus the bidding behaviour of the hydrogen storage should be added to Powerflex. The bidding behaviour of the storage unit can be modelled by making dispatch decisions to maximise the profit in a year based on the hourly

marginal electricity and hydrogen price. This could argue for a profit maximising objective function for the hydrogen storage. However, the overall objective of Powerflex is to maximise social welfare. Moreover, demand is inelastic in Powerflex which implies that the social welfare maximisation can be reduced to a cost minimisation problem (Jägemann et al., 2013). The hydrogen storage is therefore modelled with a cost minimising objective function, which makes it possible to integrate the objective function of the hydrogen storage into the overall objective function of Powerflex.

Hydrogen storage aiming for cost minimisation would imply that the storage will never charge as this would remain its costs at zero. In order to solve this issue, the opportunity costs are included in the objective function. The opportunity costs are expressed by the revenues that could be earned by discharging electricity or selling hydrogen in the hydrogen market at a moment later in time.

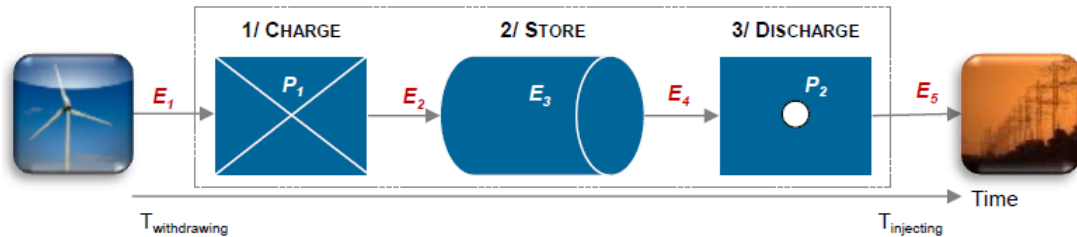


Figure 4.1: Schematic representation of a storage; hydrogen sale is not included in this figure (SBC Energy Institute, 2014)

4.2. Structural assumptions

Several structural assumptions have been made for the design of the hydrogen storage, which are related to the hydrogen market and the operation of the hydrogen storage itself. The assumptions were made in order to simplify the algorithm of the storage function, keeping the main goal in mind to capture the bidding behaviour of the storage within Powerflex. Decisions on simplifications have been made based on time constraints: extending the function would lead to a more realistic storage operation but also require substantially more time, both in terms of programming time as well as running time.

With regard to the hydrogen market, it is assumed that hydrogen production by electrolysis will produce part of the hydrogen demand in 2030 and the remaining hydrogen demand will be fulfilled through steam reforming of natural gas (SMR). It is assumed that the hydrogen market is very large so that hydrogen can be sold unrestrictedly by hydrogen demand. The SMR technology is thus considered the only competitive option to electrolysis in the hydrogen market in 2030. In such hydrogen market, SMR is the price setter as the marginal costs of SMR are higher than the marginal costs of electrolysis. This is due to the fact that SMR uses natural gas as a fuel whereas electrolysis takes advantage of low electricity prices in a system with a large share of variable renewables. The hourly hydrogen price in the model is based on the production costs of hydrogen through SMR.

This assumption was made because hydrogen production by electrolysis can be competitive to hydrogen produced by SMR in 2030 (Hers et al., 2018). It is expected that the price of natural gas will rise in the coming years, whereas the electricity price will lower because of the larger share of renewables in the grid. Moreover, the capital costs of hydrogen production with electrolysis from wind and solar energy production are currently high but they are expected to decrease towards 2030. Figure 4.2 shows the projected trends in integral supply-chain costs of three routes of hydrogen production (Hers et al., 2018). Figure 4.3 shows expectations in integral and marginal supply-chain costs of hydrogen production from natural gas with SMR and from solar and wind energy production with electrolysis. It can be seen that SMR and electrolysis can become competitive by 2030.

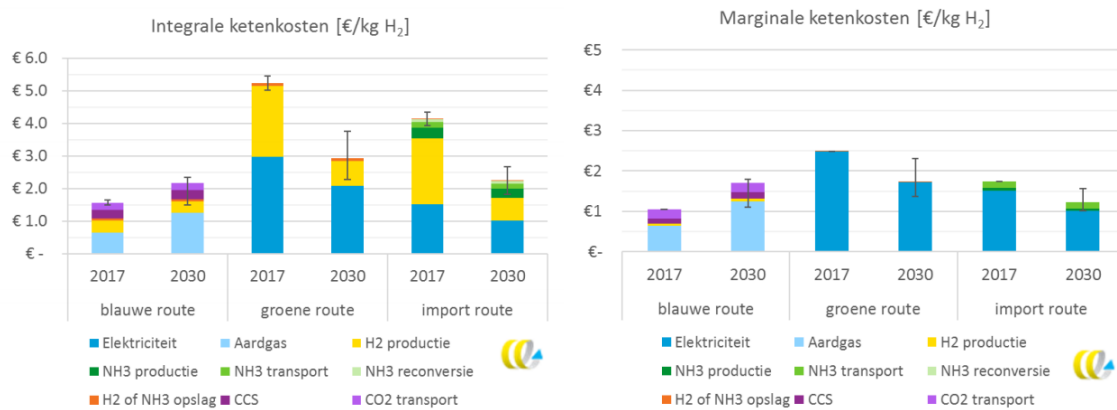


Figure 4.2: Projected trends in integral and marginal supply-chain costs of three routes of hydrogen production. In this, 'blauwe route' means hydrogen production from SMR with natural gas, 'groene route' means hydrogen production with electrolysis from solar and wind generation and 'import route' means import of hydrogen produced with solar energy abroad. (Hers et al., 2018)

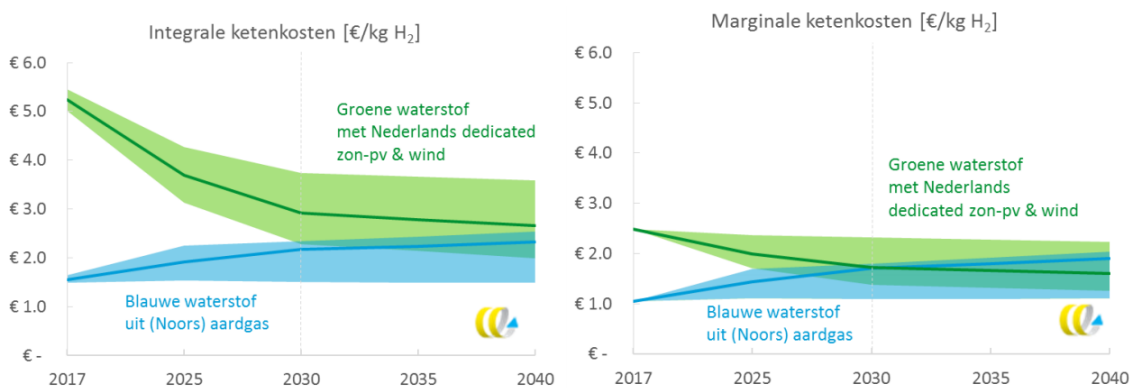


Figure 4.3: Expectations in integral and marginal supply-chain costs of two routes of hydrogen production. In this, 'blauwe route' means hydrogen production from SMR with natural gas and 'groene route' means hydrogen production with electrolysis from solar and wind generation. (Hers et al., 2018)

Concerning the operation of the hydrogen storage, one assumption is that the hydrogen storage can either charge or discharge in one hour and cannot perform both actions at the same time. This would not influence the behaviour of an electrical energy storage as such storage performs energy arbitrage based on the peak and off-peak electricity price only and such prices would not occur simultaneously. However, in case of the hydrogen storage, arbitrage is based on hydrogen sale at the hydrogen price as well. The assumption to not charge and discharge in the same hour will thus lead to a less realistic hydrogen storage behaviour, as for example off-peak electricity prices and peak hydrogen prices can coexist. In such situations it would be logical behaviour if the storage would produce hydrogen based on the off-peak electricity price and sell this hydrogen for the peak hydrogen price in the same hour. This less realistic behaviour should be taken into account in analysing the results of this study.

Another assumption is that the storage cannot discharge electricity and sell hydrogen at the same time. This assumption could be justified by the strongly varying electricity price. In theory the electricity price and hydrogen price can be exactly the same in one hour and electricity discharge and hydrogen sale would happen simultaneously. However, such event will rarely occur in practice and there will always be one of the two options that will generate more revenue than the other.

Moreover, the discharging capacity is considered to be the same for hydrogen sale and discharging electricity, the latter corrected for the efficiency of the re-conversion step. In reality there is a difference in volume between re-injection of electricity in the grid and hydrogen in for example a gas pipe.

In addition, the same efficiency is used for full load and part load operation of the storage and it is assumed that the storage is empty at the beginning of the year. The self-discharge rate is neglected in the module, as bulk energy storage can be characterised by a very low self-discharge.

In some particular cases, when efficiencies and prices are similar, it can be possible that charging, discharging or idle state all lead to a cost minimisation for multiple consecutive hours. For these cases, priorities are added to the operational options. The assumption is made that the idle state has the highest priority because this leads to the least wear and after that come the charging and discharging state. This means that the storage will be in idle mode as long as possible, which is true in the case of perfect foresight like in Powerflex. However, when prices are uncertain as is the case in reality, the charging or discharging state would have highest priority in the very first hour.

4.3. Mathematical representation

The storage module characteristics and operation can be captured in a mathematical representation, which consists of an objective function subject to several constraints.

4.3.1. Objective function

The objective of a hydrogen storage is to minimise the total operational costs in a year. The objective function is given in equation 4.1, with t a time step of one hour and T the total number of hours in a year.

$$\text{Minimise } C^{\text{storage}} = \sum_{t \in T} (C(P_{\text{charging},t}) - R(P_{\text{discharging},t}) - R(S_{\text{hydrogen},t})) \quad (4.1)$$

Equation 4.2, 4.3 and 4.4 define the components that together form the total operational costs.

Equation 4.2 shows the charging cost as a function of the charging capacity $P_{\text{charging},t}$ in hour t . The charging capacity is corrected for the charging efficiency η_{charging} and multiplied by the electricity price in hour t in order to obtain the costs of charging in hour t .

$$C(P_{\text{charging},t}) = P_{\text{charging},t} * (1/\eta_{\text{charging}}) * \lambda_t \quad (4.2)$$

Equation 4.3 gives the revenue of discharging electricity as a function of the discharging capacity $P_{\text{discharging},t}$ in hour t . Discharging is subject to a discharging efficiency $\eta_{\text{discharging}}$ and multiplied by the electricity price in hour t in order to obtain the revenue of charging in hour t . The round trip efficiency of the hydrogen storage is defined by $\eta_{\text{roundtrip}} = \eta_{\text{charging}} * \eta_{\text{discharging}}$.

$$R(P_{\text{discharging},t}) = P_{\text{discharging},t} * \eta_{\text{discharging}} * \lambda_t \quad (4.3)$$

In equation 4.3 the revenue of hydrogen sale with capacity $S_{\text{hydrogen},t}$ at a hydrogen price $P_{\text{hydrogen},t}$ in hour t is shown. It is assumed that discharging by means of hydrogen sale is not prone to a discharging efficiency.

$$R(S_{\text{hydrogen},t}) = S_{\text{hydrogen},t} * \text{Price}_{\text{hydrogen},t} \quad (4.4)$$

4.3.2. Constraints

The objective function is subject to several constraints that describe the technical limitations of the hydrogen storage. Inequality 4.5 shows how the energy content of the hydrogen storage is limited to E_{min} en E_{max} , the minimum and maximum energy capacity respectively. The sum of charged energy minus the discharged energy cannot exceed the energy capacity limits for all consecutive hours of the year.

$$E_{\text{min}} \leq \sum_{t=i}^j (P_{\text{charging},t} - P_{\text{discharging},t} - S_{\text{hydrogen},t}) \leq E_{\text{max}} \quad \forall i, j \quad (4.5)$$

The other constraints are shown by the inequalities in 4.6, 4.7 and 4.8 and are related to the limits of the charging, discharging and hydrogen sale capacity. It is assumed that hydrogen can be sold with the same capacity as the discharging capacity.

$$0 \leq P_{charging,t} \leq P_{charging,max} \quad (4.6)$$

$$0 \leq P_{discharging,t} \leq P_{discharging,max} \quad (4.7)$$

$$0 \leq S_{hydrogen,t} \leq P_{discharging,max} \quad (4.8)$$

4.4. Hydrogen storage in Powerflex

The hydrogen storage is included as a separate function in the lambda iteration method in Powerflex. In the lambda iteration method it is checked whether the load can be supplied at minimal system marginal costs or whether the system marginal costs have to be adjusted. This allows the storage output to participate in the economic dispatch problem, together with the outputs of the thermal generators.

The addition of hydrogen storage leads to an adjusted overall objective function of Powerflex: the storage costs can be added to the minimisation of total system costs. The adjusted overall objective function is given in equation 4.9, with t a time step of one hour, T the total number of hours, n a single generator, N the total number of generators in the system, m a single storage module and M the total number of storage modules in the system.

$$\text{Minimise } C^{total} = \left(\sum_{t \in T} \sum_{n \in N} (C^{fuel}(P_{n,t}) + C_{n,t}^{startup} + C_{n,t}^{maint}) u_{n,t} \right) + \sum_{m \in M} C_m^{storage} \quad (4.9)$$

The storage output serves to levelise the load, can take on different charging or discharging levels and can either participate in the supply curve or in the demand curve of Powerflex. The unit commitment and economic dispatch procedure of the storage unit is therefore designed as an economic-scheduling problem with multiple states, where each state represents different levels of either production or consumption. The hydrogen storage can be included in the load constraint of Powerflex on either the supply or demand side. When the storage produces, it is discharging and participates in the supply side. Charging means that the storage consumes electricity and therefore participates in the demand side. Equation 4.10 shows how hydrogen storage can be added to the load constraint. The sum of the powers generated by the committed thermal units and storage modules should satisfy the demand P_t^{load} and the sum of the charging powers of all storage modules for every hour t .

$$\sum_{n \in N} P_{n,t} u_{n,t} + \sum_{m \in M} P_{discharging,m,t} = P_t^{load} + \sum_{m \in M} P_{charging,m,t} \quad \forall t \quad (4.10)$$

Integrating hydrogen storage in Powerflex requires adjustments to the input data per country. An hourly hydrogen price has been added to Powerflex and seasonal storage-specific data have been added to an Excel input file, see Figure 4.4. The hourly hydrogen price allows for the evaluation of minimal total operation costs of the storage and the storage-specific data add constraints to the operation of the storage as supply or demand in the power system.

Moreover, the inputs and outputs of the storage module have to be specified in order to integrate hydrogen storage in Powerflex. Figure 4.5 gives an overview of the connection of the storage module with Powerflex, the input Excel file and the output Excel file. Every iteration, Powerflex inputs the hourly hydrogen price, hourly electricity price, number of hours per year, total number of iterations and the current loop number in to the storage module. Additionally, seasonal storage-specific data and a country ID is taken from the input Excel file. The country ID defines the country in which the storage is located.

Every iteration, three vectors are returned from the storage module to Powerflex, called Production, Commit and Income. In Powerflex these vectors are used in the lambda iteration method. In the last iteration, the results of the storage module are written into a separate output Excel file. The results of the storage module should give insights into the operation of the storage and into the KPIs related to the storage operation: the storage utilisation in terms of stored hydrogen, sold hydrogen and sold

electricity. The derived model outputs and outputs of the storage module that are used for calculating the KPIs are given in black in Figure 4.5.

4.5. Conclusions

This chapter discussed the conceptual design of the storage module and the structural assumptions that are made. The generic storage module, used as hydrogen storage in this research, can charge, discharge and sell hydrogen to the hydrogen market at a hydrogen price of hydrogen production by SMR, which is always the price setter in a large hydrogen market. A mathematical representation of the cost minimising objective function of the hydrogen storage with its technical constraints is given, after which it is shown how the storage function is mathematically integrated into the objective function and load constraint of Powerflex. An overview is given of the adjustments to the input data of Powerflex in order to include hydrogen storage in the model. Moreover, the inputs and outputs of the storage module are shown in order to fit into Powerflex and so that the outputs result in the KPIs needed for this study.

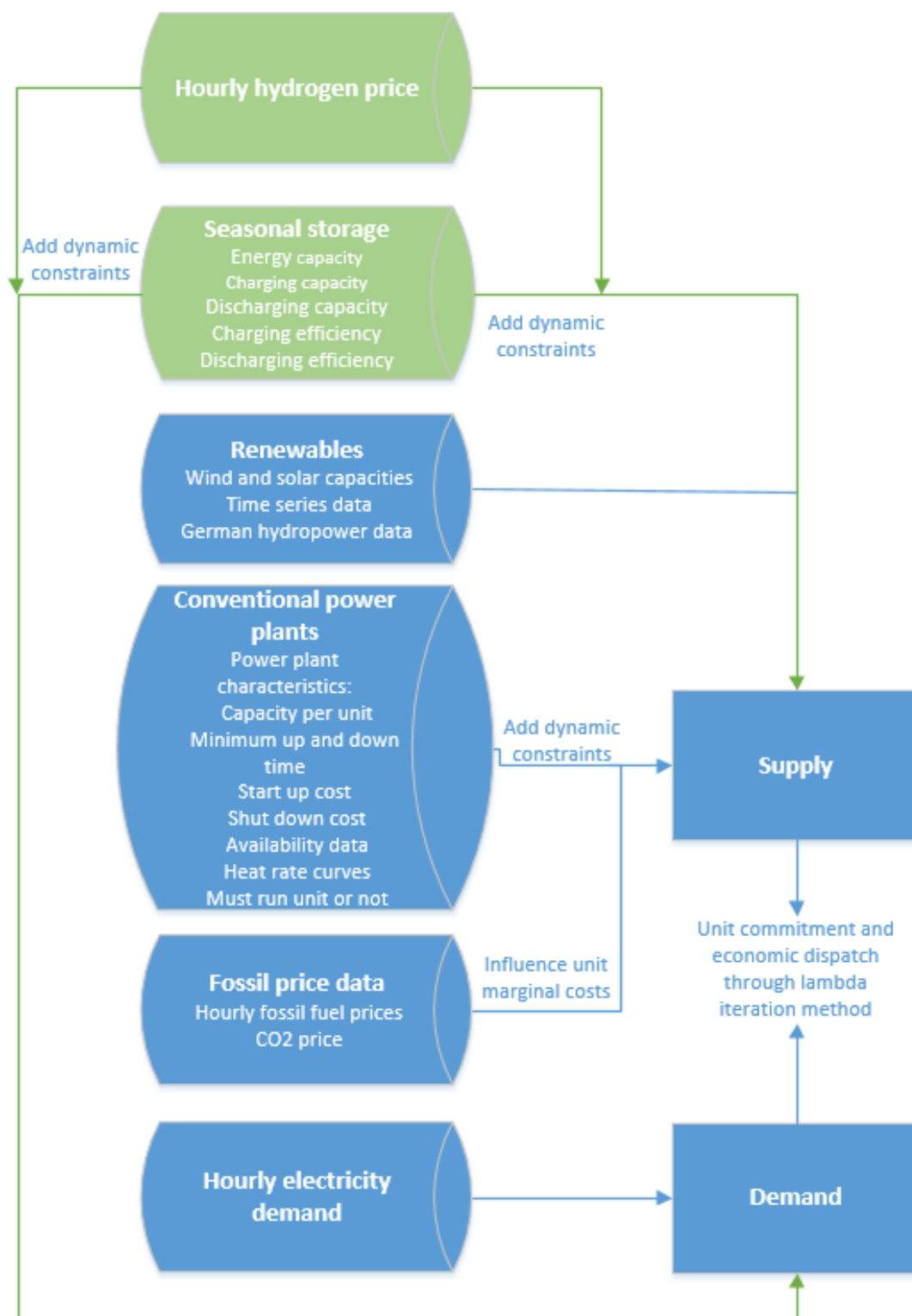


Figure 4.4: Overview of adjustments to input data per country in order to add the storage module. The adjustments are shown in green.

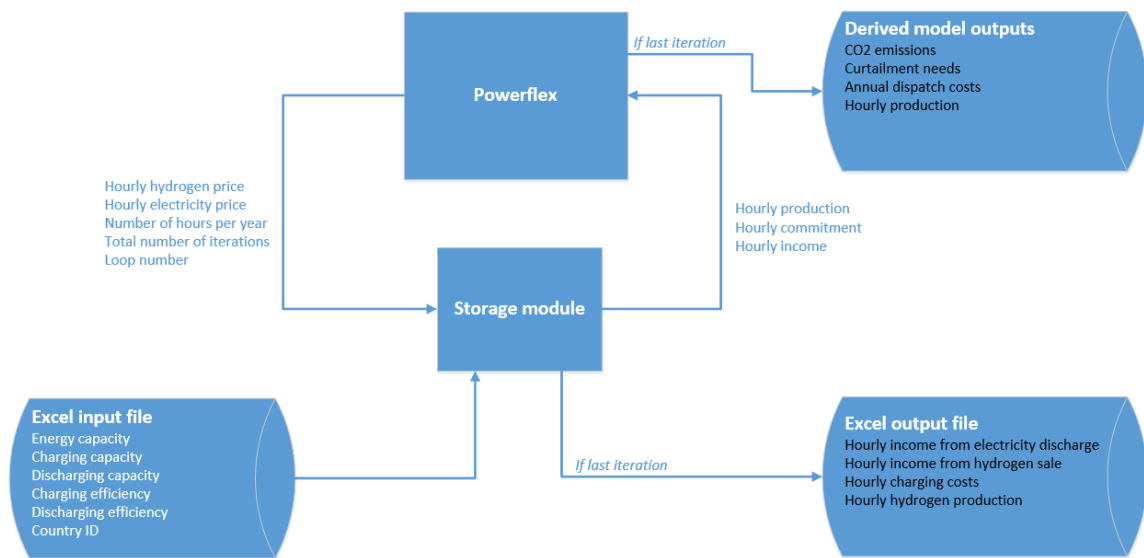


Figure 4.5: Overview of the connection of the storage module with Powerflex, the input Excel file and the output Excel file. The derived model outputs and outputs of the storage module that are used for calculating the KPIs are given in black.

5

Specification

The goal of this chapter is to describe how the conceptualisation from previous chapter has been translated into a problem that can be solved by dynamic programming. The concept and suitability of dynamic programming will be shortly explained and the general implications for the translation from storage conceptualisation to a dynamic programming formulation of this type of problem and their influence on the storage behaviour will be discussed. Thereafter, as every dynamic programming problem requires its own formulation, it will be discussed in more detail how the storage function reaches its objective to minimise costs, taking into account the energy capacity, charging capacity and discharging capacity constraints.

5.1. Dynamic programming

The storage function is also modelled according to the dynamic programming technique, because dynamic programming is already used to solve the unit commitment of power plants in Powerflex and the least-cost objective of the storage function makes the storage function suitable for dynamic programming.

Dynamic programming imposes a certain structure on the decision problem in order to split it into several sub-decisions, for each of which the optimal decision is taken. These sub-decisions happen in stages: if there are N decisions to be taken, then every decision can be associated with one of N stages (Smith, 1991). There exists a recurrence relationship: the optimal value of the decision variable in one state and stage is linked with the optimal value of it in the next stage and one or more possible states in that stage. An illustration of stages, states and the recurrence relationship is given in Figure 5.1.

Each dynamic programming problem requires its own formulation, as there is not a single general algorithm applicable to each situation (Smith, 1991). Modelling the storage function according to the dynamic programming procedure thus means that the problem has been structured in a specific way. In case of the storage function, the optimal path is determined by the hourly evolution of the energy stored in the storage so that the lowest operational cost in a year is obtained, subject to several constraints.

Splitting up the problem into stages and states implies that the energy capacity, charging capacity and discharging capacity have to be discretised. This discretisation leads to less realistic behaviour as the evolution of the charging capacity, discharging capacity and energy capacity of the storage follow a nearly continuous pattern in reality. In theory a nearly continuous behaviour could be achieved with dynamic programming by choosing a very high number of stages and states, leading to a very fine granularity of the problem.

However, this increases the number of computations that have to be made leading to a longer runtime, which is proportional to the product of the number of stages and the number of states. Therefore, a limited number of stages and states was chosen, considered sufficient for the level of detail of this study. A limited number of stages and states also causes rounding errors in the representation of

energy capacity, charging capacity and discharging capacity as not each capacity can be precisely reached given the limited granularity of capacity. Nonetheless, the charging, discharging and energy capacity have been modelled as variables and it is thus possible to adjust the granularity to the user's needs.

The storage function assumes perfect foresight, likewise in Powerflex. The electricity price is updated in each iteration and then the storage function is evaluated again, as a part of the lambda iteration method. The hourly electricity price and hydrogen price are thus assumed to be known for the entire year, while taking the sub-decisions leading to the minimum yearly operational costs. This assumption implies that decisions are taken in the hour with the highest price in a set of subsequent high prices, while in reality the storage would charge or discharge as soon as a high price appears. The storage can select the hours with the most optimal prices because it has a yearly overview, which is not the case in reality.

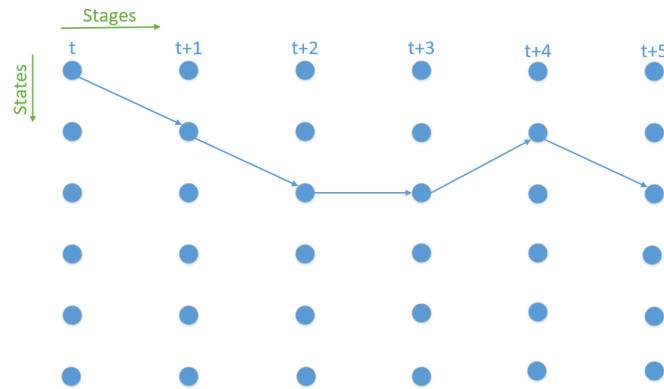


Figure 5.1: Illustration of dynamic programming: a method to find the optimal path by structuring a problem in stages and states.

5.2. Structure of storage function

This section will explain the structure of the storage function in more detail. In this dynamic programming problem, the optimal path is determined by the evolution of the energy stored in the storage so that yearly operational costs are minimised. The decision to charge is taken on the basis of the electricity price and is assumed to cost money. The decision to discharge is taken on the basis of the electricity price and the hydrogen price and is assumed to bring revenue. Revenue can be seen as opportunity costs and it minimises the operational costs of the storage.

The evolution of the energy stored is subject to several constraints. The total energy stored should always be more or equal to zero or less or equal to the maximum energy capacity. The rate at which the storage charges or discharges should always be within the maximum charging capacity and discharging capacity respectively. Moreover, the storage should also have an idle option. A charging efficiency and discharging efficiency are included to account for energy losses. These efficiencies influence the cost or the revenue of a charging or discharging decision respectively.

Dynamic programming works with stages and states. In case of the storage function, stages are the moments in time in which a decision is made: in the case of the storage function a decision is taken in every hour of the year. There are thus 8760 decision moments. States represent the amount of energy stored and are a discretisation of the total energy capacity of the storage. This can best be explained by an example. Consider an energy capacity of 80 MWh with 11 states, then state 0 represents 0 MWh of energy stored, state 1 represents 8 MWh, state 2 represents 16 MWh and so on, until state 11 of 80 MWh which represents a full energy storage. The number of states thus represents the granularity of the total energy capacity of the storage.

The energy stored can increase or decrease by a charging or discharging decision respectively. Charging or discharging thus means that the state changes; the state becomes higher when the storage is charged and the state becomes lower when the storage is discharged. The charging and discharging

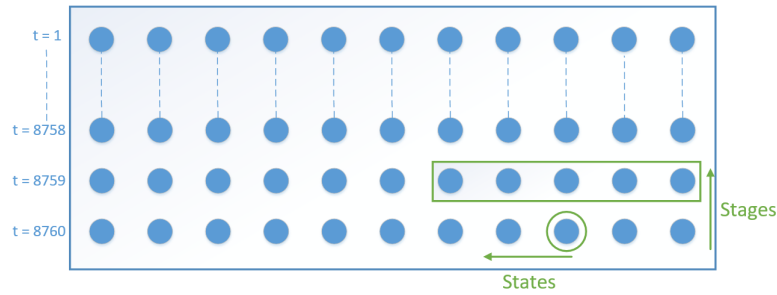


Figure 5.2: Stages and states in dynamic programming and what they represent in the hydrogen storage function. The green circle indicates the current state in t and the green box selects all states that it could possibly reach in $t+1$.

capacity are therefore also discretised and represented by a number of states. To build upon the previous example of the 80 MWh storage where one state per stage represents 8 MWh: a 16 MW charging capacity is represented by a maximum increase of 2 states per stage. A discharging capacity of 8 MW is represented by a decrease of 1 state per stage.

The charging and discharging capacity can thus be used to indicate the range of states that can be reached in stage $t+1$ from a certain level (state) of energy stored in stage t . The stages and states of the dynamic programming problem are translated into a matrix in Matlab as is shown in Figure 5.2. The function shifts through this matrix in order to evaluate the minimum costs of all possible combinations of state in t and the states it could possibly reach in $t+1$. Figure 5.3 shows how the energy capacity constrain is respected. All states outside the energy capacity bounds are set to infinity and will therefore not be selected as possible next state, as this would never lead to minimum costs.

With a discharging capacity of 8 MW it will not be possible to completely empty a full 80 MWh energy storage within an hour. Or in other words, to move from state 11 to state 1 in an hour. Moreover, because of the discretisation, the charging and discharging capacity are represented by the full number of states that correspond with the charging or discharging limits. In case of the example: a charging capacity of 18 MW will thus be represented by a maximum of 2 states or 16 MW.

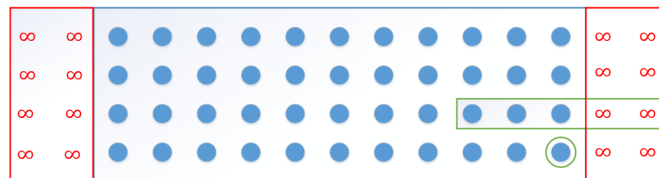


Figure 5.3: Respecting the energy capacity constraint: all states outside the energy capacity bounds are set to infinity and will therefore not be selected

Dynamic programming works with a backward loop which goes backward in time, and a forward loop which goes forward in time. Firstly, the backward loop is evaluated: it contains the optimal lowest cost value for each state in each stage. In the forward loop the optimal path is determined by tracing back the optimal state in each stage. This is shown in Figure 5.4.

The purpose of the backward loop is to find the minimum costs for each state in each stage. This minimum cost value is called the continuation value for a state in a stage. The continuation value is defined as the continuation value in the previous state plus the margin that will be made by the transition to the next state. The margin is defined as the difference in energy stored between two states in two subsequent hours multiplied by the price in that hour.

The backward loop thus starts at the last stage of the year, hour T , and moves backwards to the first hour of the year. The continuation value in hour T is zero and the state with the minimum continuation value in hour 1 indicates that this is the best state to start from. Because all continuation values are determined in the backward loop, it will be known which state in a certain stage costs less than the

other states at that moment in time. Also it will be known how the continuation value in that state is obtained as it is based on the continuation value in the next state in hour $t+1$ plus a margin based on the state difference.

This is the basis for the forward loop. The forward loop starts in the state with the maximum continuation value in stage 1 and from there the optimal path from state to state is selected by comparing the continuation value in a state with the continuation value in a possible next state and the margin that can be made with the difference between the current state and the next state. When this is equal, it means that the optimal next state is found.

Sometimes more than one next state is optimal, while only one state can be selected. In such cases, the possible next states are prioritised according to the following assumptions. The state for which the storage has to do the least is selected first, as it is assumed that this minimises wear. This leads to the following prioritisation: neither charge or discharge, charge less than fully, discharge less than fully, charge fully, discharge fully.

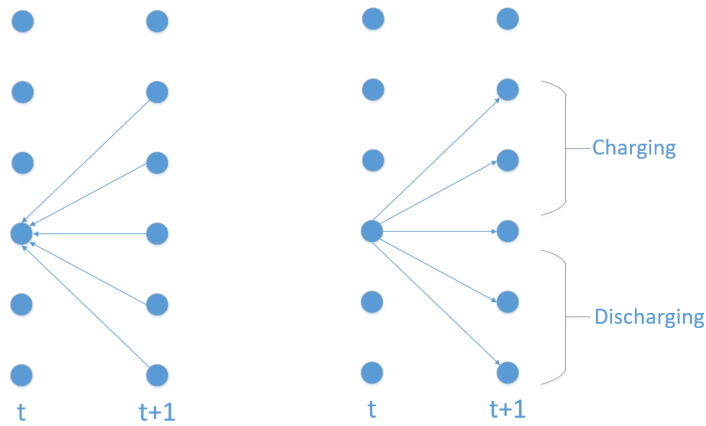


Figure 5.4: Illustration of the backward and forward loop in dynamic programming

5.3. Conclusions

The goal of this chapter was to describe how the concepts from the conceptualisation phase have been translated into a dynamic programming problem. A dynamic programming problem implies that a decision problem is broken into several sequential sub-decisions which together have a recurrence relation. The energy capacity, charging capacity and discharging capacity constraints have been discretised in order to evaluate the sub-decisions, with the objective to minimise operational costs. Moreover, it has been explained how the storage function evaluates all possible states in search for the optimal path, thereby respecting the storage constraints. The storage function was modelled with the assumption of perfect foresight, so it can select hours with the most optimal prices because it has a yearly overview.

Verification & Validation

This chapter discusses the verification and validation of the energy storage module and its implementation in Powerflex. Several verification tests are performed to check whether the model meets the requirements defined in the conceptualisation phase of this study. Thereafter, the validation part of this chapter will discuss to what extent the model results are reliable. Convergence issues with the model occurred during the validation process. Therefore, this will be explained in more detail in the additional Section 6.2. The results of a sensitivity analysis are presented in the final part of this chapter. A sensitivity analysis checks whether relations between variables in the model work correctly and it shows how robust the model results are to uncertainties in model inputs.

6.1. Verification

Model verification is meant to assure a correct computer programming and implementation of the conceptual model. Or in other words, are the concepts of energy storage translated correctly into the computer model? Several different methods are used to verify the storage function, namely debugging, extreme value analysis and boundary analysis. The following paragraphs will discuss these methods and their results.

6.1.1. Debugging

In the process of writing the function in Matlab, the function has been tested multiple times in order to reveal errors in the code. In some cases the Matlab coding environment indicated certain errors such as 'Index exceeds matrix dimensions' or 'Subscript indices must either be real positive integers or logicals'. The location of these errors was then detected by means of debugging. After the source of the error was located, a change was made and the model was retested to ensure that the modification was successful.

Debugging was performed with different techniques, for example by execution tracing, execution monitoring or execution profiling, which means that the line-by-line execution of the model was 'watched', the correctness of what the model is doing during execution was checked or the number of times a certain loop was called respectively.

Moreover, Matlab offers the possibility to add breakpoints to pause a run at certain lines of code or to indicate where an error occurs by means of 'dbstop if error'. When the run -time of the function had to be improved, Matlab's profiler was used to see which lines of code were slowing down the model's execution the most.

Additionally, an energy storage was built in Excel by means of the dynamic programming algorithm. This file is used to verify the storage function in Matlab. The same storage characteristics in both Excel and Matlab were used and errors could be located by comparing the outcomes of both.

6.1.2. Extreme value analysis

The storage function should be capable of handling a wide range of electricity and hydrogen prices. Extreme value analysis is used to see whether the model behaves as expected when the electricity and hydrogen prices have extreme values. Charging and discharging capacity are both set to 90 MW and the energy storage is large enough to be able to charge for the entire year. Both the electricity price and the hydrogen price have been set to either -10000 euro/MWh, 10000 euro/MWh, 0 euro/MWh or an ordinary price pattern that can occur in reality (see Figure 6.1). The function has been run for different combinations of these prices; for instance an electricity price of 0 and a hydrogen price of -10000 euro/MWh. In all cases, the behaviour could be explained and some examples of the behaviour for extreme prices are given in Figure 6.2, 6.3 and 6.4.

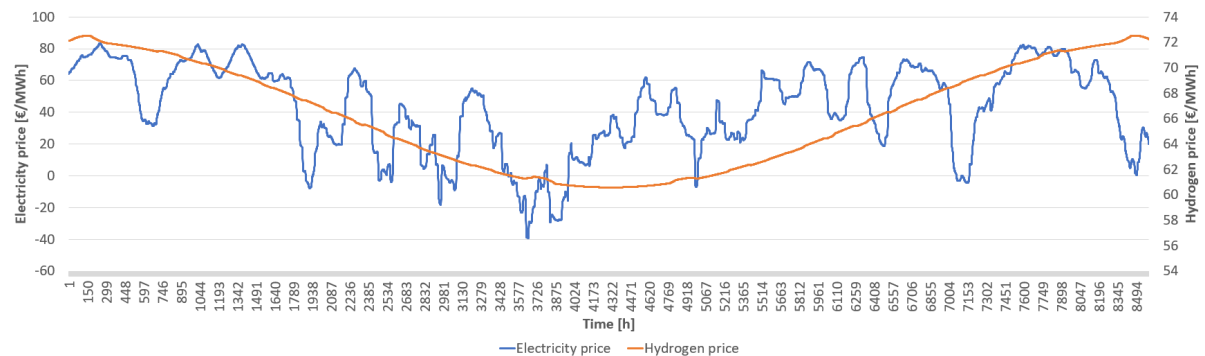


Figure 6.1: Electricity and hydrogen price pattern, used as ordinary price patterns in some cases of the the extreme value analysis

In these graphs, charging and discharging are indicated with a negative and positive sign respectively. Hydrogen sale, electricity sale and total energy stored show the course of the stored energy in the buffer. They are defined by a weekly moving average of the cumulative function of discharging through hydrogen sale, discharging through electricity sale and the sum of both respectively. When energy stored is negative, this means that energy is accumulating in the buffer whereas a positive energy stored indicates that more energy is leaving the buffer than energy is stored. The weekly moving average of the charging capacity shows the response to the electricity price as well as to the hydrogen price; the storage might choose to charge when the hydrogen price is comparatively high.

Figure 6.2 shows the result of extreme value analysis for an electricity price of 0 €/MWh and an ordinary hydrogen price. Charging is costless and money can be earned by discharging the storage through hydrogen sale, so hydrogen sale will lower the costs. Production peaks and valleys are visible at the beginning of the year, which can be explained by the high hydrogen price at the beginning of the year.

The more pronounced charging and discharging cycles in these hours allow the storage to lower its costs in these hours of high hydrogen price. After these first hours, the storage starts to make more balanced charging and discharging cycles. In the middle of the year, the unit is charging more whereas it discharges more at the end of the year. This leads to a lower moving average in the middle of the year as compared to the end of the year and corresponds to the evolution of the hydrogen price: lower in the middle of the year and higher at the end of the year. The stored energy is sold only through hydrogen sale as electricity sale cannot result in revenue due to the electricity price being 0 €/MWh.

Figure 6.3 gives the result of extreme value analysis with an ordinary electricity price and a hydrogen price of 10000 €/MWh. The storage unit follows the course of the electricity price while charging and sells all the hydrogen at an extremely high hydrogen price. This leads to equally divided charging and discharging cycles as the hydrogen price is continuously high. Hydrogen sale lowers the costs throughout the year in the same manner and no electricity is sold. There are a few little peaks in the curve with total energy stored, which is caused by some extra hours of charging at very low electricity prices in order to sell the hydrogen later on.

The result of extreme value analysis with an electricity price of -10000 €/MWh and an ordinary hydrogen price is given in Figure 6.4. The storage charges continuously as charging at a negative electricity price lowers the costs maximally: charging even leads to revenues for the storage. The total

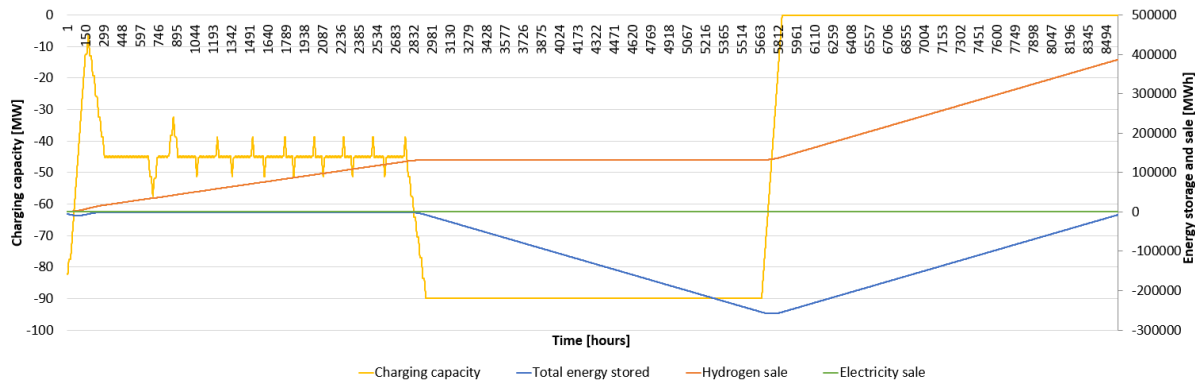


Figure 6.2: Results of verification through extreme value analysis with electricity price 0 euro/MWh and ordinary hydrogen price

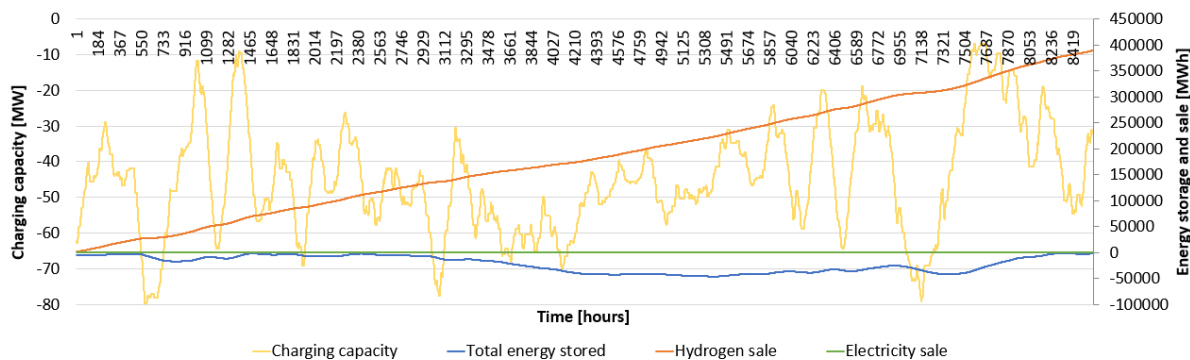


Figure 6.3: Results of verification through extreme value analysis with ordinary electricity price and hydrogen price of 10000 €/MWh

stored energy increases and no energy is sold. Figure 6.2, 6.3 and 6.4 thus show that the storage function can handle extreme values of electricity price and hydrogen price and optimises its charging and discharging cycles according to its perfect foresight of the price evolution throughout the year.

6.1.3. Boundary analysis

Boundary analysis is used to test how the model responds to test cases where the input data is exactly the same. It is checked how the model behaves for equal electricity and hydrogen price. Equivalent to the extreme value analysis, the charging and discharging capacity are both set to 90 MW and the energy storage is large enough to be able to charge for the entire year.

Figure 6.5 shows the model output for the electricity price being equal to the hydrogen price. The storage does not charge and no energy is stored. The costs of charging are always higher than the revenue of selling hydrogen or electricity, which can be explained by the charging and discharging efficiency. Charging implies a conversion from electricity to hydrogen at a certain efficiency, causing losses and the costs of charging to be higher than the electricity price according to $P_{charging,t} \cdot (1/\eta_{charging}) \cdot \lambda_t$. Discharging can be done by hydrogen sale or electricity sale, the first at a hydrogen price equal to the electricity price and the latter at a re-conversion efficiency, so again leading to losses. The storage will thus never be able to sufficiently decrease its costs by the revenue of selling hydrogen or electricity and it thus does not charge.

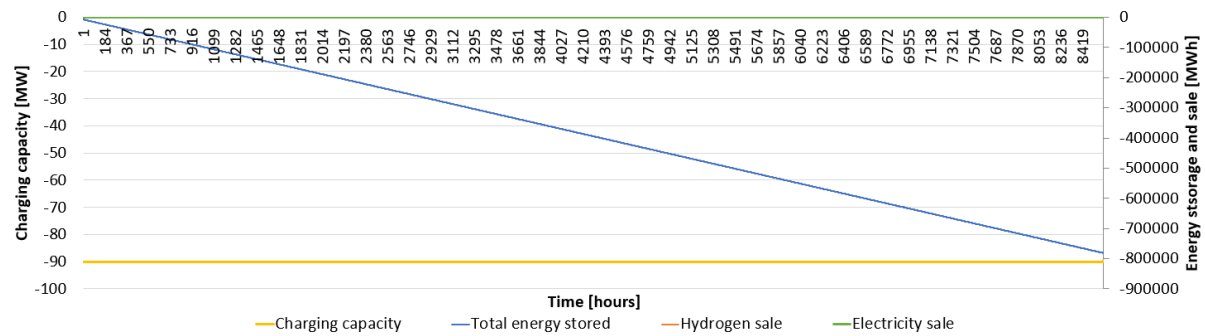


Figure 6.4: Results of verification through extreme value analysis with electricity price of -10000 €/MWh and ordinary hydrogen price

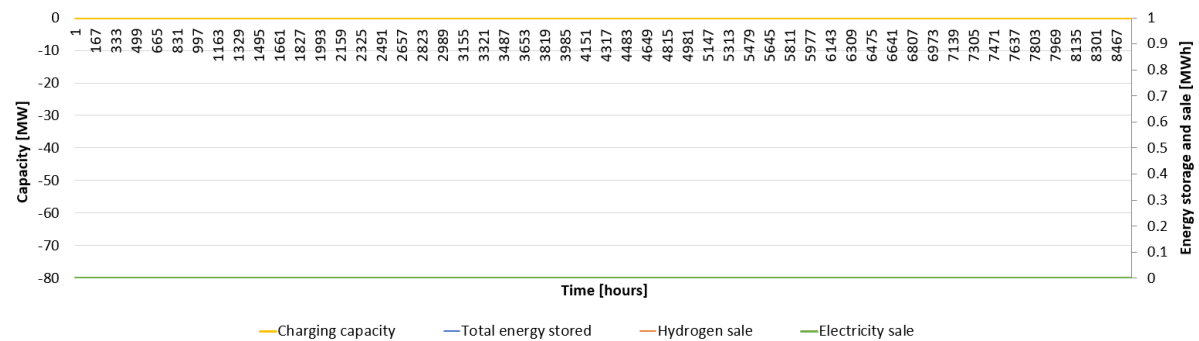


Figure 6.5: Result of verification through boundary analysis with equal electricity price and hydrogen price

6.2. Model convergence

PowerFlex is a deterministic model with a finite horizon: it has an hourly resolution and models a year predefined in the input data. The model iterates following the lambda iteration method. This method should eventually lead to a converged solution to the unit commitment and economic dispatch problem. A converged solution means that the hourly mismatch between demand and supply is minimised.

PowerFlex outputs three graphs at the end of the last iteration of a run, which give an overview of the convergence process throughout the iterations. The first graph shows the yearly average power price in the home country, which is the Netherlands in this case. This graph shows how the average power price varies between iterations. The aim is to obtain an approximately stable power price which indicates that an optimal system marginal cost profile has been found within the number of replications. The second graph concerns the average imbalance, which is the yearly average of the hourly mismatch between supply and demand in a run. The third graph shows the average absolute imbalance. This is the yearly average of the absolute hourly mismatch between demand and supply. The average absolute imbalance should ideally vary around zero whereas the average imbalance should approach 0 GW (Hers et al., 2016).

In Hers et al. (2016) the model converges towards an average absolute imbalance and average imbalance of 0 GW. However, in that report the model was run for historic data with not much RES capacity and without storage capacity. More progressive scenarios with a larger share of RES and with the integration of storage capacity cause convergence issues in Powerflex. The following two paragraphs explain what has been tried to let the model results converge.

6.2.1. Model convergence with storage integration

Adding storage to the model can influence the convergence of the model due to its price-responsive behaviour in the lambda iteration method. For example, when the electricity price is low and a large total storage capacity starts to charge all at once, this leads to a sudden large increase in demand and

thus a large mismatch between supply and demand. Similarly, a high electricity price can cause the total storage capacity to discharge, also leading to a large imbalance in the system.

This price-responsive behaviour with abrupt on/off-decisions can differ between iterations and can cause an unsolvable imbalance as a mismatch continues to exist in every iteration. This could be called a typical integer problem due to the abrupt integer on/off decisions. It is thus needed to model the storage in such way that it does not cause an unsolvable imbalance between the iterations.

The influence of the storage on the model convergence can depend on three storage-related factors: the number of units that together cover the total storage capacity in a country, the number of states and the efficiency difference between the units. However, these three factors also influence the run time of the model and the storage behaviour. The more detailed the three factors are chosen, the more realistic the storage behaviour but the longer the run time. Moreover, the number of iterations of the model is another factor to take into account.

The storage behaviour is considered realistic enough for the purpose of this study when the storage responds to price signals and bids in the market in such a way that the corresponding model imbalance is within acceptable limits. An imbalance is considered acceptable when it forms a relatively small part of the total supply and demand in the system. Storage settings leading to acceptable results have been found by using a storage capacity of 15 GW that covers the maximum negative residual demand in the Netherlands in a originally converging scenario with a conservative RES capacity.

Firstly, the number of states was chosen and this concerns the operation of an individual storage unit. A higher number of states implies that more precise levels of energy in the storage can be achieved. The storage then has the possibility to work at half or even smaller charging or discharging capacity in certain hours as the level of detail is higher. However, some test runs showed that the storage almost always chooses to work at full capacity for both the charging and discharging step. For this reason it is decided that it is sufficient to represent one charging or discharging step with one state. This led to modelling the storage with 2190 states (8760 hours in a year / 4) in order to cover three months with either a charging or a discharging step. This allows the storage to work as a seasonal storage by storing energy up to three months and to discharge that energy completely during the next three months.

Secondly, the total storage capacity is split up in smaller individual units that together cover the total storage capacity in a country. Each of these individual units then has a more realistic capacity and its on/off-decision will less drastically influence the imbalance in the system. It was found that a higher number of individual storage units leads to a smaller average absolute imbalance in the model. It could thus be argued that ideally a large level of detail is needed in order to model storage as realistically as possible and to limit the influence of an on/off-decision on the model convergence.

In reality, the largest plant currently operating based on electrolysis has a maximum stacked capacity of 150 MW (SBC Energy Institute, 2014). However, splitting up the total electrolysis capacity in the Dutch electricity system into units of 150 MW would require 100 storage units with a capacity of 150 MW each. This would mean a large increase in run time. It was therefore chosen to make a simplification by assuming that multiple plants are aggregated and respond in a similar way to price fluctuations as they would do separately.

Thirdly, the efficiency difference is used to let the storage units respond more smoothly to price fluctuations. When 10 storage units that together cover 15 GW, will start to charge or discharge all at once, this will lead to large imbalances between power demand or supply. In reality none of the storage units is expected to have the exact same efficiency, as the efficiency is influenced by many different technical details. By giving each storage unit in the model a slightly different efficiency (+/- 0.01 % difference) each storage unit will respond slightly different to price fluctuations, leading to a smoother response and more realistic results.

Various test runs with varying number of model iterations, number of individual storage units together covering a capacity of 15 GW, efficiency difference and number of states have thus been run in order to analyse what settings would be suitable. It was decided to run the model with 25 iterations, 9 individual

storage units covering the total storage capacity per country, 2190 states and an efficiency difference of 0.01 %. The convergence graphs of this run are given in Figure 6.6.

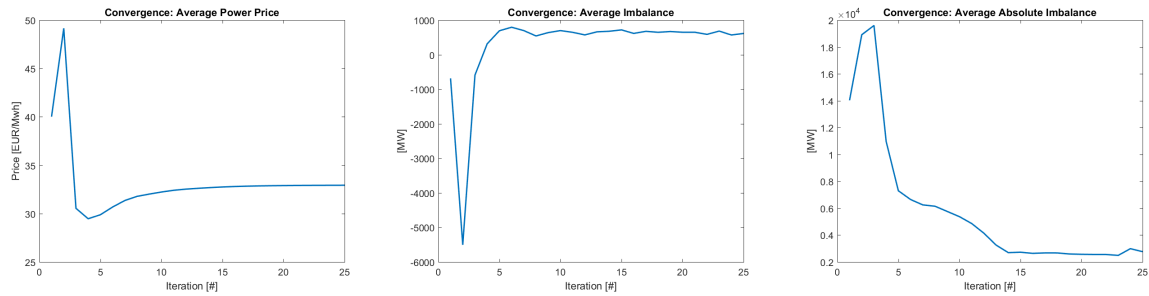


Figure 6.6: Model convergence for a conservative RES scenario with 15 GW storage capacity. The graphs show that electricity price, average imbalance and average absolute imbalance converge within 25 iterations.

6.2.2. Model convergence with a large share of RES

A large share of RES in the model causes hours with a large overproduction or underproduction, leading to a larger mismatch between supply and demand. The modelled power system needs to be sufficiently flexible in order to deal with these mismatches. Powerflex contains three flexibility options: storage capacity, back-up generation capacity and cross-border generation capacity.

A large RES capacity and insufficient flexibility could cause the following dynamics in Powerflex. In hours of underproduction, the model tries to solve the mismatch between demand and supply by operating the back-up generation capacity and discharging storage capacity in the system. This leads to an increased electricity price in every iteration. In hours of overproduction, the mismatch could be solved by charging the storage capacity. However, when the storage capacity is insufficient to deal with the overproduction, this leads to a strongly decreasing electricity price in every iteration and a mismatch that cannot be solved.

Various test runs have been performed in order to check if these dynamics indeed take place. The test runs with and without storage in a system with a conservative RES capacity in Section 6.2.1 proved that adding storage with the correct settings does not result in additional convergence issues. Test runs with and without a large RES capacity proved that the model does not converge for large RES capacities. Additionally, test runs have been performed with large RES capacity and a varying storage capacity. It was found that the model does only converge for high RES scenarios where the storage capacity covers at least 50 % of the maximum negative residual demand in a country.

For this study it is needed to model a power system with a large RES capacity and varying storage capacities. However, this also includes non-converging scenarios with storage capacity that covers only 25% of the national maximum negative residual demand. It has therefore been tried to remove the hours with extremely high or low electricity prices (the overshoot hours) and their corresponding imbalance in order to show that only these hours cause the average imbalance in the system. Removing the overshoot hours should lead to a converged solution.

The overshoot hours have been removed based on two different lines of reasoning. The first reasoning was that the overshoot hours are outliers in the electricity price time series. However, removing the outliers by using SPSS did not lead to a converged solution. The second reasoning was that all electricity prices lower than or equal to zero euro per MWh will not occur in the real system. The high electricity prices were selected based on the assumption that peaking power plants, mostly gas plants, are price-setters in hours of high prices, resulting in removing prices higher than or equal to 150 euro per MWh. Also this approach did not result in a converging solution. It should thus be concluded that model runs with a high RES capacity and insufficient flexible capacity do not converge due to a model artefact.

6.3. Validation

With model validation it is checked whether the data used in the model is valid and whether the model's behaviour is accurate enough for its intended purpose. Does the function's behaviour in isolation and within PowerFlex approach reality accurately enough to answer the research questions?

An attempt was made to validate the storage function in isolation with historic data. The function can be seen as a pure energy storage when it is run without the option to sell hydrogen. Hourly production data of a French pumped hydro storage (PHS) for the year 2015 and the hourly electricity price in that year were found. This data could be used to see whether the storage unit production pattern is similar to that of the PHS, given the same electricity prices as input.

However, several issues with the available data arose. The hourly production of the PHS never reaches the maximum turbine or pumping capacity and the total energy stored exceeds the maximum energy storage capacity of the PHS considerably. This can possibly be caused by natural inflows, but additional PHS data such as natural inflow or reservoir level of the PHS are unavailable.

Even though the storage function's behaviour showed similarities to the behaviour of the PHS, validating the storage function with historic data was deemed insufficient because of missing data. It was difficult to find other historic production data as there are not many price-driven storage units in the current electricity system. Therefore, it was chosen to validate the model by means of operational validation according to the behaviour that can be expected from literature.

6.3.1. Data validation

The data used in a model influences the model outcomes. Therefore it is important that all data is collected from reliable sources. Assumptions have to be made in case of incomplete data and these assumptions have to be validated. The model data for this thesis include power plant data, demand profiles, RES generation profiles, fuel and CO₂ price data, hydrogen storage data and interconnection data for the Netherlands and Germany. The hydrogen storage and interconnection capacity are varied in the scenario analysis, which is covered in Chapter 7.

The other data is taken from the high RES 2030 scenario in the Power to Ammonia study by CE Delft. The primary data for the Netherlands, such as installed capacities of wind and solar, fuel and CO₂ prices and demand projections, in this scenario is based on the fixed and intended policy pathway for 2030 in the National Energy Outlook which is published by ECN & PBL in 2015. The primary data for Germany is taken from their Grid Development Plan for 2030.

Power plant data for both countries are derived from CE Delft's proprietary data set and adjusted for the installed capacities in the 2030 scenario. Moreover, PowerFlex considers seasonal and hourly demand profiles and seasonal and hourly variability of wind speeds and solar radiation, based on data about wind speed, irradiation and actual sun hours in 2013. These assumptions were made for the Power to Ammonia study and therefore considered accurate for this thesis as well.

For the hydrogen storage the efficiency of the electrolyser is set to 75 %, which is based on the PEM technology and is a typical value according to the literature review by Blanco and Faaij (2018). The efficiency of the fuel cell or combined cycle gas turbine for re-conversion of hydrogen to electricity is set to 60% (Blanco and Faaij, 2018; SBC Energy Institute, 2014). These efficiencies of the electrolyser and the fuel cell together result in a round-trip efficiency of 45 % which is a typical value for Power-to-Hydrogen-to-Power.

A sensitivity analysis is performed to analyse how sensitive the model outcomes are for certain parameter ranges. Section 6.4 discusses the results of this analysis.

6.3.2. Operational validation of storage function in isolation

Operational validation of the storage function in isolation is performed in two ways. Firstly, it is checked whether the maximum charging and discharging capacity are maintained. Secondly, it is checked whether the storage cycles match the dimensions of the charging capacity, discharging capacity and the energy capacity. Charging and discharging capacity were set at 10 MW and energy storage capacity

at a minimum of 0 MWh and a maximum of 100 MWh. The energy storage thus needs ten hours to be fully charged and ten hours to be fully discharged. The number of states is 11, which leads to an energy granularity of 10 MWh.

Figure 6.7 shows the input electricity and hydrogen prices for the operational validation of the storage function. The graph only shows hour 1 until 34, but the function was run for the entire year and the electricity price and hydrogen price continue as 4 and 0 €/MWh respectively throughout the remaining year. The prices are the basis for the margins in Figure 6.8. The prices are chosen in such way that the resulting margins lead to predictable behaviour.

Figure 6.8 shows that the charging margin is low until hour 14 and becomes high thereafter. This means that the costs are low until hour 14 and higher in the hours thereafter. The opposite holds for the margin for hydrogen sale. That margin can decrease the costs the most from hour 14 on, as the margin is the most negative in these hours, also compared to the margin for electricity sale.

Consequently, the storage will fully charge in the hours 1 until 14 and fully discharge in the hours thereafter. As was discussed in Section 4.2, the assumption is made that the idle state has the highest priority because this leads to the least wear and after that come the charging and discharging state. The storage will thus wait to charge and discharge until the last hours with beneficial margins. This behaviour is visible in Figure 6.9. Additionally, the figure shows that the maximum charging and discharging capacity are maintained.

Figure 6.10 shows that the course of the total stored energy in the storage corresponds to the charging and discharging steps. Moreover, the minimum and maximum energy storage capacity are maintained. It can thus be concluded from this operational validation that the storage function shows the behaviour that can be expected.

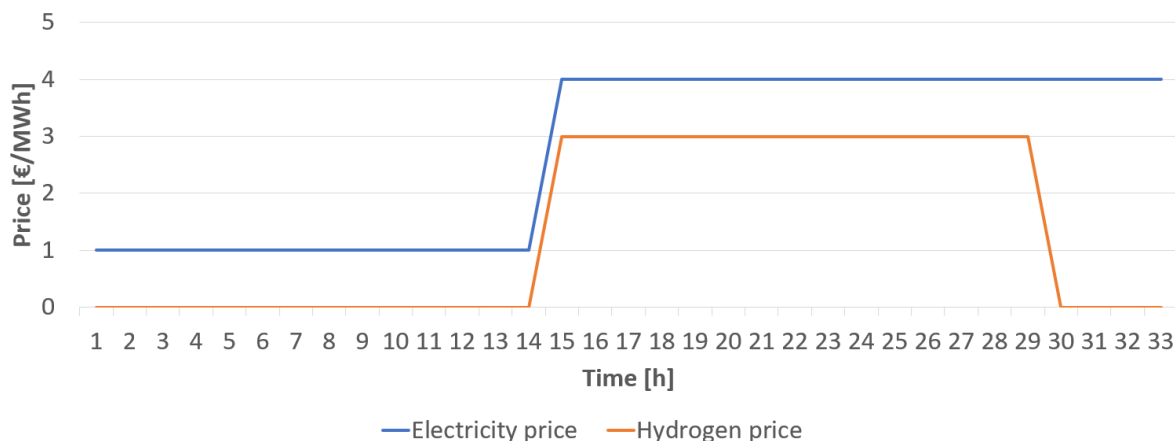


Figure 6.7: Hourly electricity and hydrogen price used as input for operational validation of storage function

6.3.3. Operational validation of storage function within PowerFlex

Operational validation of the storage function within PowerFlex is performed through analysing two characteristic power system analysis curves for the Dutch power system with and without storage: the price duration curve and the flow duration curve. According to literature, these curves will look differently for a power system with storage than for a system without storage. Storage was only added to the Dutch power system in order to see the effects of storage in a more isolated manner. Additionally, the electricity prices and storage production are plotted in time to see how the storage responds to different price levels and scatter plots of residual demand and electricity prices are made to check how the storage behaviour, electricity prices and residual demand are interrelated.

Firstly, the charging, discharging and energy capacity of the storage are defined. An electricity storage optimises its behaviour by charging and discharging cycles based on price differences. It was chosen to model a storage energy capacity large enough to charge for a week as this would allow for

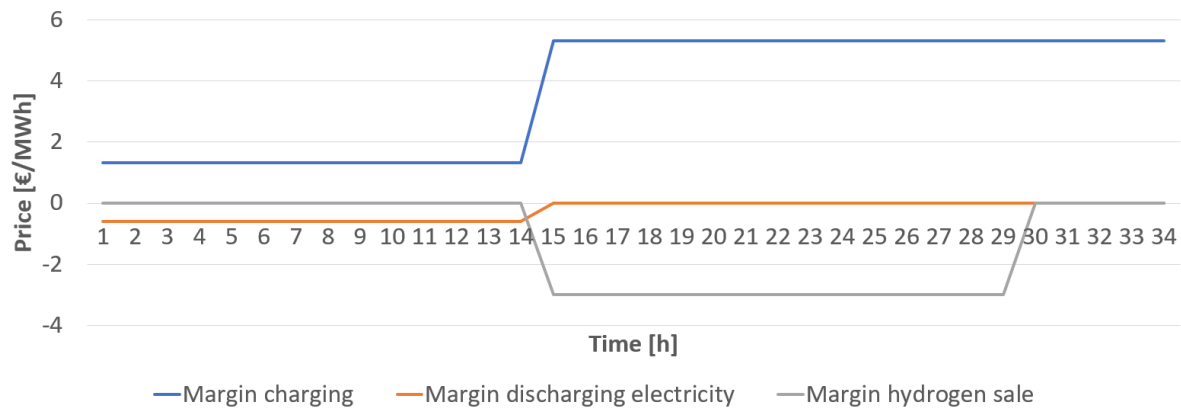


Figure 6.8: Hourly electricity and hydrogen margins in operational validation of storage function

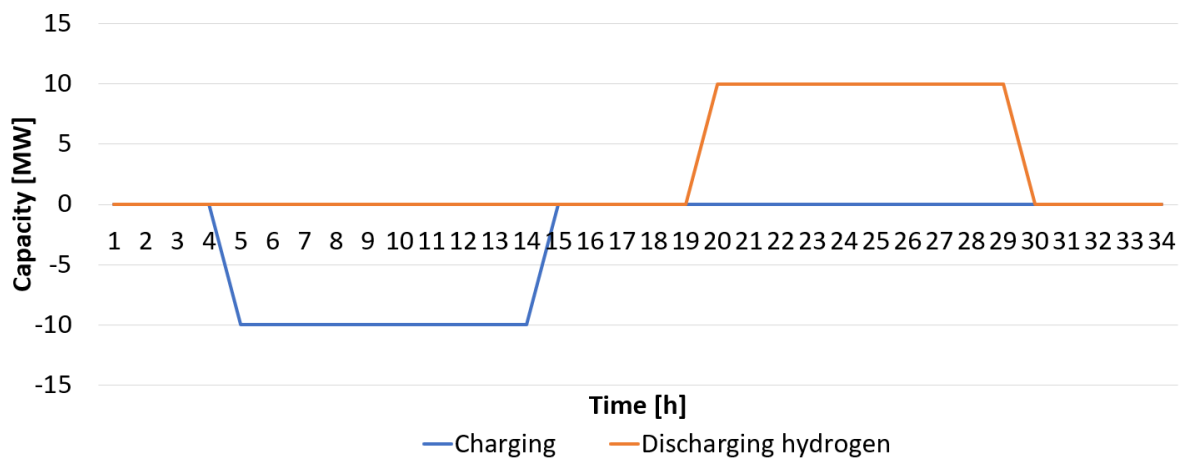


Figure 6.9: Hourly charging and discharging capacity results in operational validation of storage function

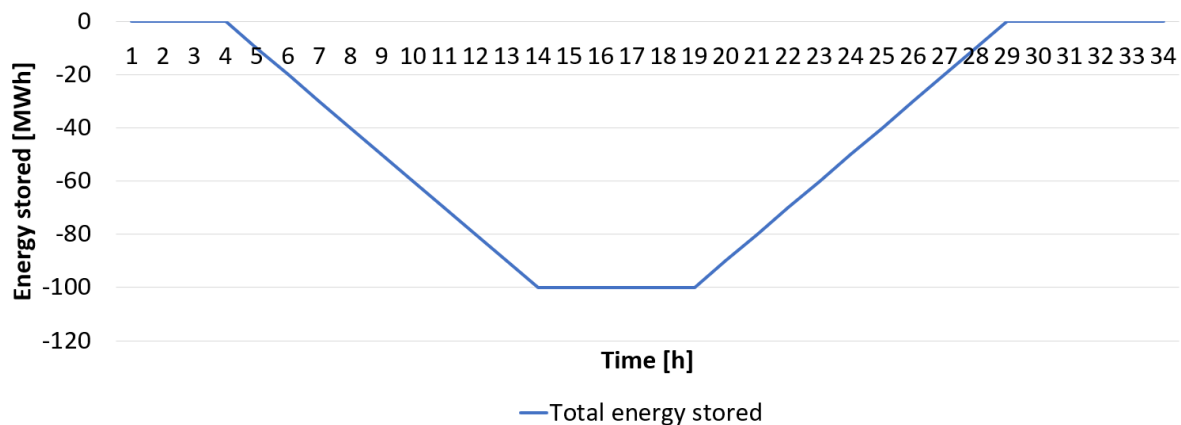


Figure 6.10: Course of total energy stored in operational validation of storage function

multiple cycles in the year. The residual demand curve has been plotted in order to define the storage potential, which is as large as the maximum negative residual demand. Charging and discharging capacity are both set to 20 GW and a possibility to charge for one week, implies an energy storage capacity of $168 \text{ hours} \times 20000 \text{ MW} = 3360000 \text{ MWh}$.

In the price duration curve (Figure 6.11 of the Dutch power system without storage there are many hours with very low and very negative prices, caused by a mismatch between demand and supply. As

expected, adding sufficient storage capacity to the system decreases the number of hours of negative prices by charging and removes the largest price peaks by discharging. The electricity prices in a system with storage are thus less extreme, but nevertheless hours with very negative prices still exist. These very negative prices occur in the few situations where negative residual demand is larger than the charging capacity of the storage.

The price duration curve for the system with storage shows a few price plateaus which can be explained. One price plateau occurs near an electricity price of 0 €/MWh. These prices correspond to large negative residual demand levels that can just be handled by the storage charging capacity. Another price plateau occurs thereafter, corresponding to a large set of electricity prices varying within a certain price range. This is caused by peak shaving of the storage. The storage responds to price extremes outside a certain price range. These prices allow the storage to minimise its costs, given the charging and discharging efficiencies of the storage.

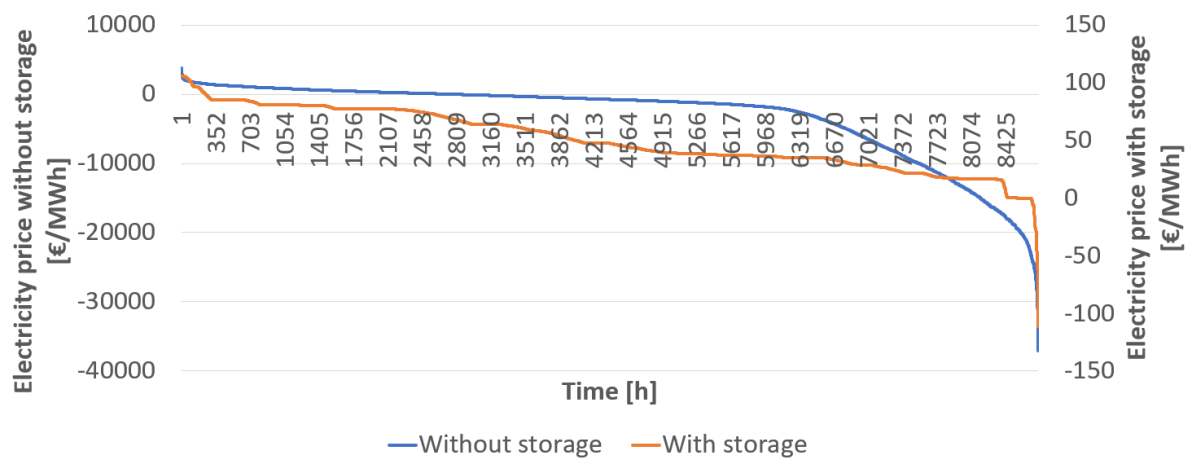


Figure 6.11: Result of validation: a shift in the price duration curve can be seen for a power system with storage as compared to a power system without storage.

Figure 6.12 shows this peak shaving in more detail. The storage responds to electricity prices by charging and discharging, causing the electricity price to remain within a certain price range. Some electricity prices seem to be outside the range in the figure, like the electricity at hour 169. However, this is caused by the level of detail of the graph, as was checked manually for these hours. The prices are within the same range and it is thus correct that the storage does not charge or discharge in these hours.

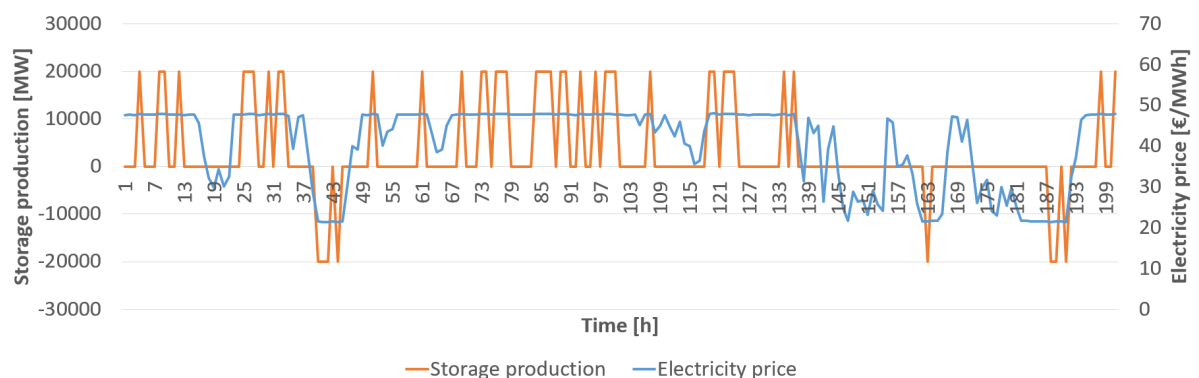


Figure 6.12: Result of validation: zooming in on hourly electricity prices and corresponding storage production levels.

Figure 6.13 shows that storage leads to a shift in the flow duration curve. There is more electricity export than import in the system without storage. However, adding storage to the Dutch power system leads to fewer hours of export and more hours of import. This is according to expectations, as a large storage capacity in the Netherlands leads to more flexibility in the Dutch system as compared to the

German system without storage capacity. The German system does however also need flexibility to balance out the fluctuations of its large share of variable renewables. The Dutch storage thus also stores part of the renewable energy generation of the German system, leading to more import than export in the system with storage.

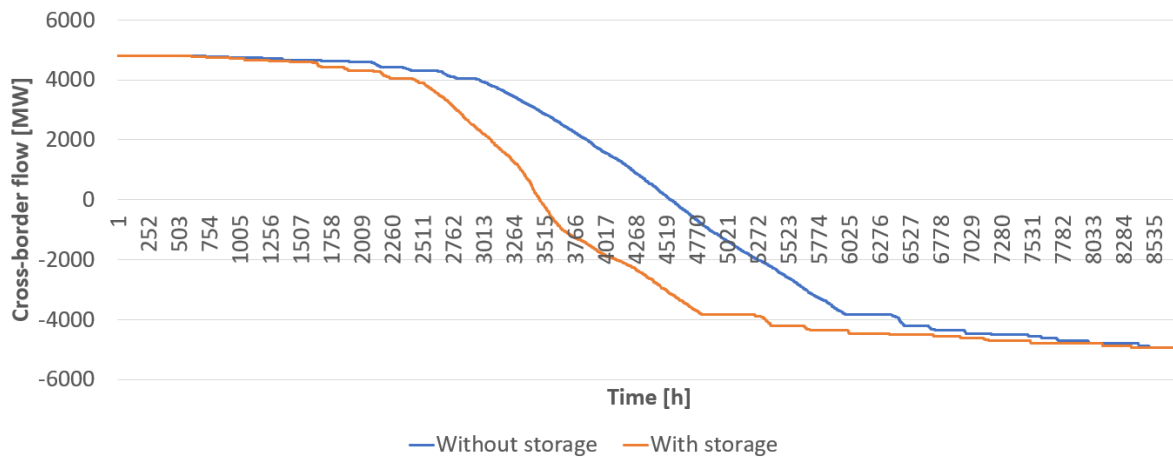


Figure 6.13: Result of validation: a shift in the flow duration curve can be seen for a power system with storage as compared to a power system without storage. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

The electricity prices are related to the residual demand in the system and so is the storage behaviour. Moreover, the storage behaviour influences the residual demand as it increases the demand while charging and decreases the demand while discharging. The residual demand is also influenced by the cross-border power transfer, as importing electricity decreases the residual demand and exporting electricity increases the residual demand.

Scatter plots of residual demand and electricity prices are made to check how the storage behaviour, electricity prices and residual demand are interrelated. The scatter plots are made for a system without and with storage, in order to see how the presence of storage influences the interrelationship. Figure 6.14 shows the scatter plot of the electricity prices as a function of the residual demand in a system without storage. The residual demand has been corrected for the cross-border power transfer. Electricity prices and residual demand both occur in a wide range of extreme values. Very extreme negative electricity prices only occur when the residual demand is negative. The model cannot find a solution for these situations as demand and supply cannot be matched and therefore keeps decreasing the electricity price in every iteration. Other negative electricity prices occur when residual demand is positive. This is caused by electricity imports and exports from Germany and extremely negative prices in that country.

Figure 6.15 shows the scatter plot of the electricity prices as a function of the residual demand in a system with storage. As expected, electricity prices occur in a smaller range and are not as extreme as in a system without storage. Moreover, residual demand is defined in a smaller range due to the peak shaving of the charging and discharging cycles of the storage, which influence the residual demand.

Ideally, the presence of storage should lead to fewer hours of extremely negative residual demand than in a system without storage. The storage should start charging in such hours, leading to a less negative or even positive residual demand. Moreover, a negative residual demand should correspond to negative electricity prices. However, this is different from the scatter plot in Figure 6.15, where a negative residual demand mostly corresponds to positive electricity prices.

This effect cannot be caused by cross-border power transfer from Germany in order to level the electricity price between both countries. Importing electricity would happen when the electricity price in Germany is lower than the price in the Netherlands. Export of electricity would happen when the electricity price in Germany is higher than the price in the Netherlands. In both cases, a positive Dutch

electricity price will not occur when the residual demand is still negative as a negative residual demand indicates a power insufficiency in the Netherlands. This issue has not been investigated further due to time constraints. The issue might influence the study outcomes and this will be discussed further in the discussion in Chapter 8.

An additional issue noticed during the validation, is that the producer costs are higher than the producer revenue, thus meaning that producer income is negative. This is an odd model outcome, as this should imply that none of the producers will produce as it will not bring them any profit. However, the producers do supply in Powerflex even though this results in financial losses. This issue has also not been investigated further due to time constraints, but might influence the study outcomes and will therefore be discussed further in the discussion in Chapter 8.

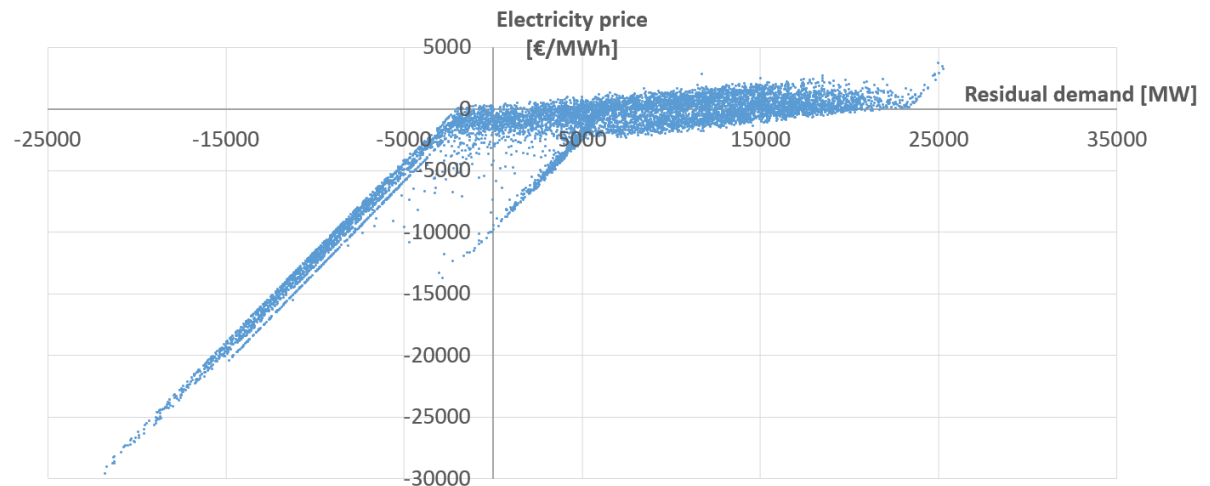


Figure 6.14: Result of validation: scatter plot of the electricity price as a function of the residual demand. Residual demand has been corrected for the cross-border power transfer: importing electricity decreases the residual demand and exporting electricity increases the residual demand.

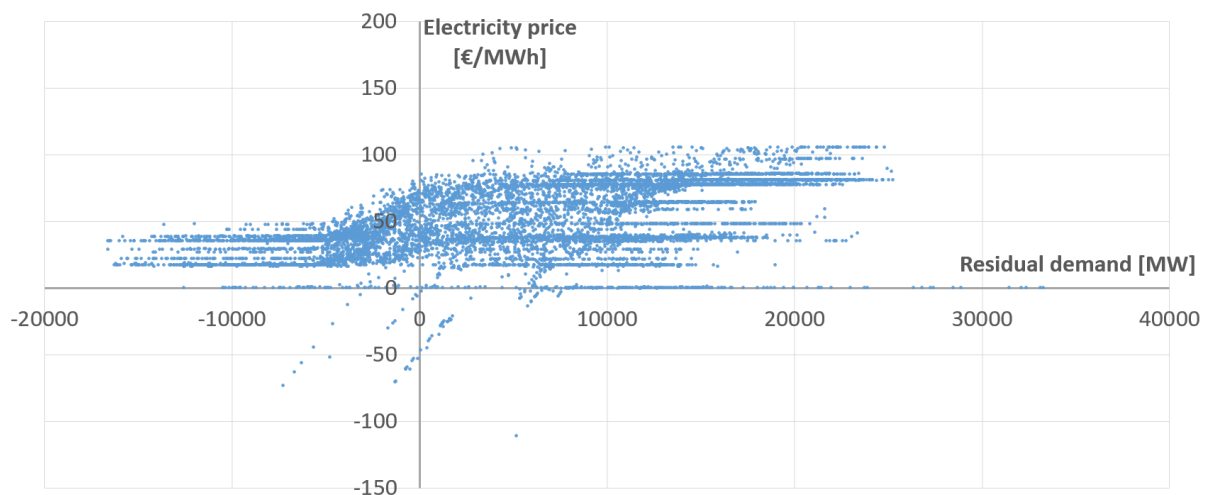


Figure 6.15: Result of validation: scatter plot of the electricity price as a function of the residual demand. Residual demand has been corrected for the cross-border power transfer and the storage behaviour. Importing electricity decreases the residual demand and exporting electricity increases the residual demand. Charging increases the residual demand and discharging decreases the residual demand.

6.4. Sensitivity analysis

The sensitivity analysis is intended to see how sensitive the model outputs are to small variations in the inputs, as compared to the base case. The original inputs of the base case are varied with $\pm 10\%$ and this results in a shift in the output variables. Output variables with a shift larger than $\pm 10\%$ are considered sensitive to that particular input. A sensitivity analysis is performed for two reasons. Firstly, it is used to validate the relations between inputs and outputs of the model. Secondly, it shows the impact of uncertain variables in the model.

The selection of input variables is based on their uncertain nature and the difficulty to direct these variables in the preferred direction. Such variables are called external factors and they could potentially influence the model outcomes if their value in reality turns out to be much different from the assumed value in the model. If their influence in a sensitivity analysis on the model is large, these variables are often used to compose scenarios for the scenario analysis. In such cases, the sensitivity analysis thus serves as input for the scenario analysis.

However, the aim of this study is to analyse the effects of cross-border transmission capacity and seasonal storage on one another and the Dutch power system. Installed storage and interconnection capacities need to be varied for this purpose, which already leads to multiple scenarios as both capacities need to be varied relative to each other and a base case. To limit the amount of run-time and results of this study, it has been chosen to only perform a sensitivity analysis on the base case of this study. It is assumed that the quantitative results in the sensitivity analysis on the base case also hold true for the other scenarios in this study. In other words, it is assumed that the sensitivity of the model in the base case is similar to the sensitivity in the other scenarios.

Cross-border transmission capacity and seasonal storage capacity are both measures to affect the flexibility of the Dutch power system. Their complementarity and influence on the power system depend on the demand and supply of flexibility in the system. To know to what extent their effects on the flexibility in the system remain valid if a model assumption might be different in reality, the external factors selected for this sensitivity analysis all influence either the flexibility demand or the flexibility supply in the Netherlands and Germany. The sensitivities are analysed per performance indicator and it is checked whether input-output relations can be explained. This means that a one-at-a-time sensitivity analysis is performed. In some models interaction effects between input variables exist and in such cases a one-at-a-time sensitivity analysis is insufficient and a multivariate sensitivity analysis is needed. It is however difficult to claim whether Powerflex is a linear model and it is thus not known whether a multivariate sensitivity analysis is needed. This is left for further research.

The demand for flexibility is affected by the installed RES capacity and the renewable energy supply that follows from it. The installed RES capacity is uncertain because of technology development, governance and resulting policies and is therefore selected as a relevant external factor for this sensitivity analysis.

The Dutch wind power production pattern and solar power production pattern are varied separately and varied both at the same time, by varying their hourly energy production time series. Wind and solar power production patterns are also varied both at the same time, because Heide et al. (2010) found that the influence of wind energy on power system variability is larger than the influence of solar energy.

The Dutch electricity demand is also selected as a relevant external factor. It influences the flexibility demand in the system and is uncertain because of factors such as population growth and economic growth. The last external factor in the sensitivity analysis is the German storage capacity, as it can affect the flexibility supply in the Netherlands by means of the interconnector. The installed storage capacity in Germany is uncertain because of technology development, governance and resulting policies.

Table 6.1 shows an overview of the selected external factors, their value in the base case and their value in the sensitivity analysis scenarios after a variation of -10% or $+10\%$. The base case is a model run with 50% storage, equal to a 7.5GW electrolyser and fuel cell capacity, in the Netherlands and a 5GW interconnection capacity.

Table 6.1: Overview of the selected external factors for the sensitivity analysis, their value in the base case and their value in the sensitivity analysis scenarios

Sensitivity to	-10%	Base case	+10%
Dutch wind energy production [TWh]	60.05	66.72	73.40
Dutch solar energy production [TWh]	15.49	17.21	18.93
Dutch solar and wind energy production [TWh]	75.54	83.93	92.32
Dutch electricity demand [TWh]	111.63	124.03	136.44
German storage capacity [GW]	36	40	44

6.4.1. Sensitivity to wind energy production

In Table 6.2 the sensitivities of the performance indicators to wind energy production are given. The dispatch cost in both wind energy scenarios are higher than the base case. This seems different than expected as an increase in inexpensive wind energy production would lead to lower production costs and thus lower dispatch costs. However, it might be that more wind energy leads to hours of too large underproduction for the available storage to meet the demand. In such hours, expensive peaking power plants have to start up and produce, which might lead to an increase in annual dispatch costs. The model is not very sensitive to wind energy production considering that the relative difference is smaller than 10%. Moreover, the sign of the relative differences between the scenarios and the base case is not as expected and it is interesting to note that the influence on dispatch is not symmetric. However, the difference in symmetry is that small that it might be caused by rounding errors.

Curtailement decreases for the -10% wind energy scenario and increases for the +10% wind energy scenario, which is according to expectations. Less wind energy leads to less hours with large overproduction and thus less hours that have to be curtailed. On the contrary, more wind energy causes larger production fluctuations which need curtailment in case of overproduction. The model is sensitive to wind energy production when it comes to curtailment as the relative difference is larger than 10%. The sign of the relative differences between the scenarios and the base case is as expected. However, it is interesting to note that the influence on curtailment is not symmetric. A 10% increase of wind energy production causes a 8.75% larger difference from the base case dispatch costs than a 10% decrease in wind energy.

The model is sensitive to wind energy production when it comes to hydrogen production because the relative difference is larger than 10%. The signs are opposite and nearly equal, which is as expected as more wind energy leads to more low-priced overproduction hours to charge the storage by hydrogen production. On the other hand, less wind energy leads to less overproduction, fewer low-priced hours and thus lower hydrogen production.

The model is very sensitive to wind energy considering the electricity production; a 10% increase in wind energy leads to nearly 1.5 times more electricity production and a 10% decrease leads to half the electricity production as compared to the base case. This behaviour can be explained by the following dynamics:

More wind energy production leads to lower electricity prices in the system. This allows the storage to charge more at lower costs. Discharging the storage by electricity production implies energy losses because of the low efficiency to reconvert hydrogen into electricity. These energy losses are modelled by decreasing the potential revenue that can be earned by producing electricity. These revenues are needed to minimise the charging costs of the storage. When electricity prices are low and the storage can thus charge at low costs, lower revenues are also found sufficiently beneficial for the cost minimisation. The storage will thus find more hours where revenues are sufficient to minimise its costs and will thus produce more electricity. Similar dynamics are visible for an increasing renewable energy production in the other sensitivity scenarios.

However, the model is more sensitive than expected, which might be due to the lack of a price floor and the model decreasing the electricity prices in overproduction hours even more in every iteration. Very low electricity prices allow the storage to charge at a very low cost and thereby it can account for

more losses while discharging by electricity production. More wind energy in the system makes the low electricity prices lower and the high electricity prices unchanged as these originate from underproduction. In the hours of underproduction it will be the peaking plants that serve the demand at the same price as in the base case.

As for the hydrogen sale, the relative differences have opposite signs which is as expected as less wind energy production leads to less hydrogen production and thus less hydrogen to be sold. However, the relative change between the -10% wind and +10% wind scenario and the base case are asymmetric, which might also be caused by the very low electricity prices in the model. In all cases, except hydrogen sale, the model shows a larger relative difference for the +10% scenario than for the -10% scenario.

Figure 6.16 shows the sensitivity of the cross-border flows to wind energy production in the Netherlands. More wind energy leads to more electricity export as compared to the base case, whereas less wind energy leads to more import. This meets the expectations, as more wind energy production in the Netherlands will make it more easily possible to supply the Dutch demand and lead to more hours of overproduction, during which energy can be exported to Germany. On the contrary, with less wind energy there is a larger need for electricity from Germany to meet the demand in certain hours. The shift for more wind energy production is larger so it can be concluded that the cross-border flows are more sensitive for an increase in wind energy production than for a decrease in wind energy production.

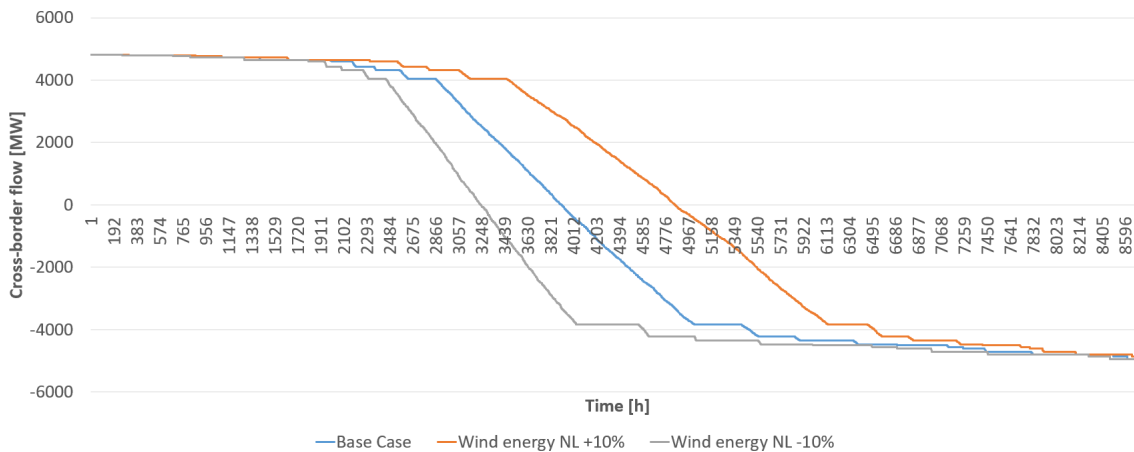


Figure 6.16: Sensitivity of cross-border flows to wind energy production in the Netherlands. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

Table 6.2: Sensitivities to +/- 10% wind energy production in the Netherlands.

Performance indicator	-10% Wind energy	Base case	+10% Wind energy
Annual dispatch cost	+3.40%	€5.08bn	+5.28%
Curtailement	-19.60%	1051h	+28.35%
Hydrogen production	-15.30%	16585863 MWh	+15.78%
Electricity production	-50.78%	1062908 MWh	+147.36%
Hydrogen sale	-10.17%	15028986 MWh	+7.19%

6.4.2. Sensitivity to solar energy production

Table 6.3 gives the sensitivities of the performance indicators to solar energy production. In general, the model is not very sensitive to solar energy production; only the electricity production undergoes a relative change of more than 10% in the solar scenarios. The dispatch cost are slightly lower than the base case for less solar energy production and slightly higher than the base case for more solar energy production. This is not as expected as more solar energy would lead to lower production costs and thus lower dispatch cost. Similarly to the scenarios with wind energy, the small increase in dispatch cost might be caused by expensive peaking power plants in hours of underproduction.

Curtailment decreases for the -10% solar energy scenario and increases for the +10% solar energy scenario, which is according to expectations, although not symmetric. Less solar energy leads to less hours with large overproduction and thus less hours that have to be curtailed. On the contrary, more solar energy causes larger production fluctuations which need curtailment in case of overproduction.

Hydrogen production is decreasing in the -10% solar energy scenario and increasing in the +10% solar energy scenario. This is as expected as more solar energy leads to more low-priced overproduction hours to charge the storage by hydrogen production. On the other hand, less solar energy leads to less overproduction, fewer low-priced hours and thus lower hydrogen production. Electricity production and hydrogen sale behave according to the same dynamics as explained in Section 6.4.1. However, the performance indicators are less sensitive to solar energy than to wind energy. This can be explained by the fact that wind energy production in the Netherlands has a larger impact in the model as it has more production hours and a larger capacity.

Figure 6.17 shows the sensitivity of the cross-border flows to solar energy production in the Netherlands. More solar energy leads to more electricity export as compared to the base case, whereas less solar energy leads to more import. This is according to expectations, as more solar energy production in the Netherlands will make it more easily possible to meet the Dutch demand and lead to more hours of overproduction, during which energy can be exported to Germany. On the contrary, with less solar energy there is a larger need for electricity from Germany to meet the demand in certain hours. The shifts in the flow duration curves are nearly symmetric and the differences from the base case are not very large, so the cross-border flows are not very sensitive to solar energy production.

Table 6.3: Sensitivities to +/- 10% solar energy production in the Netherlands.

Performance indicator	-10% Solar energy	Base case	+10% Solar energy
Annual dispatch cost	-0.20%	€5.08bn	0.37%
Curtailment	-4.76%	1051h	6.28%
Hydrogen production	-3.67%	16585863 MWh	4.96%
Electricity production	-32.45%	1062908 MWh	50.86%
Hydrogen sale	-0.24%	15028986 MWh	2.77%

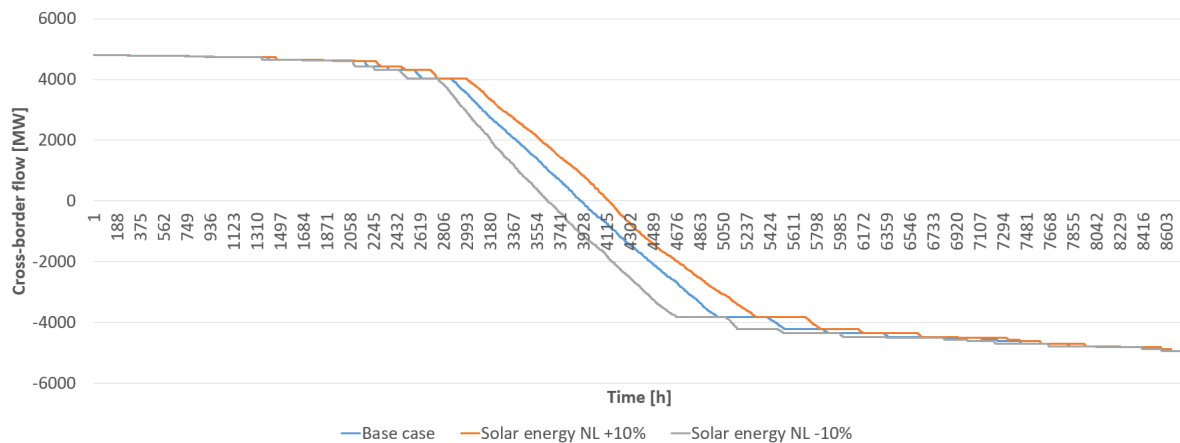


Figure 6.17: Sensitivity of cross-border flows to solar energy production in the Netherlands. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

6.4.3. Sensitivity to wind and solar energy production

In Table 6.4 the sensitivities of the performance indicators to combined wind and solar energy production are given. The dispatch cost in both renewable energy scenarios are higher than the base case. This seems different than expected as an increase in inexpensive renewable energy production would lead to lower production costs and thus lower dispatch costs. The model is not very sensitive to renewable

energy production considering that the relative difference is smaller than 10%. Moreover, the sign of the relative differences between the scenarios and the base case is not as expected and it is interesting to note that the influence on dispatch is not symmetric. However, the difference in symmetry is that small that it might be caused by rounding errors.

Curtailment decreases for the -10% renewable energy scenario and increases for the +10% renewable energy scenario, which is according to expectations. Less renewable energy leads to less hours with large overproduction and thus less hours that have to be curtailed. On the contrary, more renewable energy causes larger production fluctuations which need curtailment in case of overproduction. The model is sensitive to renewable energy production when it comes to curtailment as the relative difference is larger than 10%. It is interesting to note that the influence on curtailment is not symmetric. A 10% increase of wind energy production causes a 11.42% larger difference from the base case dispatch costs than a 10% decrease in wind energy. This is similar to the wind-only scenarios, although the difference is larger.

Hydrogen production is decreasing in the -10% solar energy scenario and increasing in the +10% solar energy scenario. This is as expected as more renewable energy leads to more low-priced overproduction hours to charge the storage by hydrogen production. On the other hand, less renewable energy leads to less overproduction, fewer low-priced hours and thus lower hydrogen production. Electricity production and hydrogen sale behave according to the same dynamics as explained in Section 6.4.1. The performance indicators are very sensitive due to the combined effect of solar and wind energy.

Figure 6.18 shows the sensitivity of the cross-border flows to RES energy production in the Netherlands. More renewable energy leads to more electricity export as compared to the base case, whereas less renewable energy leads to more import. This is as expected because more renewable energy production in the Netherlands will make it more easily possible to meet the Dutch demand and lead to more hours of overproduction, during which energy can be exported to Germany. On the contrary, with less renewable energy there is a larger need for electricity from Germany to meet the demand in certain hours. The asymmetric shifts in the flow duration curves are comparable to the shifts for the wind-only scenarios, which indicates that the cross-border flows are more sensitive to wind energy production than to solar energy production.

Table 6.4: Sensitivities to +/- 10% combined wind and solar energy production in the Netherlands.

Performance indicator	-10% Wind&Solar	Base case	+10% Wind&Solar
Annual dispatch cost	+3.83%	€5.08bn	+7.22%
Curtailment	-21.98%	1051h	+33.40%
Hydrogen production	-17.32%	16585863 MWh	+18.71%
Electricity production	-63.09%	1062908 MWh	+182.05%
Hydrogen sale	-11.63%	15028986 MWh	+7.44%

6.4.4. Sensitivity to electricity demand in the Netherlands

In Table 6.5 the sensitivities of the performance indicators to Dutch electricity demand are shown. The dispatch costs are sensitive to a change in demand. A higher demand increases the dispatch costs, whereas a lower demand decreases the dispatch costs. This is according to expectations as it is more expensive to supply a high demand than to supply a low demand with the same renewable and thermal generation capacity. There will be more hours in which the relatively expensive thermal generation capacity is needed to meet the demand. Note that the dispatch costs are more sensitive to an increase in demand than to a decrease in demand.

Curtailment increases for the -10% demand scenario and decreases for the +10% demand scenario, which is according to expectations. Curtailment takes place in hours of overproduction, so when renewable energy production is larger than the demand. If demand is high, fewer overproduction hours will occur. On the contrary, a low demand leads to more overproduction hours and thus requires more curtailment. Similar to the dispatch cost, note that curtailment is much more sensitive to an increase in demand than to a decrease in demand.

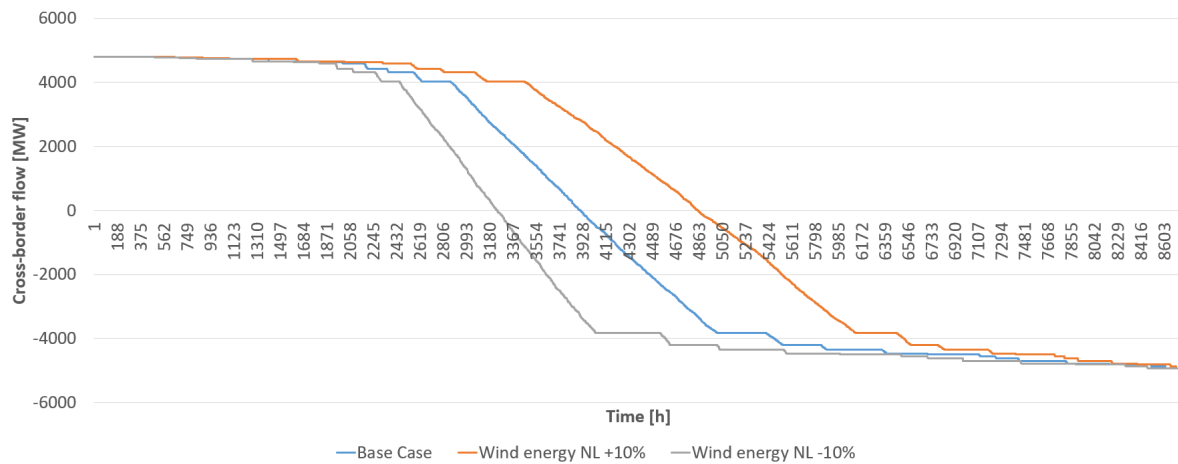


Figure 6.18: Sensitivity of cross-border flows to combined solar and wind energy production in the Netherlands. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

Hydrogen production is increasing in the -10% demand scenario and decreasing in the +10% demand scenario. This is as expected as a low demand leads to more low-priced overproduction hours to charge the storage by hydrogen production. On the other hand, a large demand implies less overproduction, fewer low-priced hours and thus lower hydrogen production. Electricity production and hydrogen sale behave according to the same dynamics as explained in Section 6.4.1. However, it is a lower demand that decreases prices and a higher demand that increases prices, as opposed to the effect of more and less renewable energy.

Figure 6.19 shows the sensitivity of the cross-border flows to Dutch electricity demand. A larger demand leads to more import and a smaller demand leads to more export, compared to the base case. This meets expectations because when demand is large, the system needs more energy to supply this demand and will therefore import from Germany. When demand is small, there will be more unused energy which can be exported to Germany. The model is sensitive to the Dutch electricity demand as the shifts in the flow duration curves are large.

Table 6.5: Sensitivities to +/- 10% electricity demand in the Netherlands.

Performance indicator	-10% Demand	Base case	+10% Demand
Annual dispatch cost	-10.38%	€5.08bn	+13.00%
Curtailment	+0.95	1051h	-14.94%
Hydrogen production	+19.11%	16585863 MWh	-17.70%
Electricity production	+74.61%	1062908 MWh	+7.62%
Hydrogen sale	+16.39%	15028986 MWh	-16.91%

6.4.5. Sensitivity to storage capacity in Germany

Table 6.6 shows the sensitivities of the performance indicators to German storage capacity. The dispatch costs are not very sensitive to a change in storage capacity. Both scenarios lead to slightly lower dispatch costs, although the change due to the +10% storage capacity is relatively larger. It can be expected that a smaller storage in Germany leads to lower dispatch costs in the Netherlands as more low-cost renewable energy will be imported to the Netherlands. This is also visible in Figure 6.20. Surprisingly, dispatch costs decrease when German storage is larger. The larger storage causes more export of renewable energy from the Netherlands to Germany (see Figure 6.20) and is thus expected to increase the dispatch costs in the Netherlands. This is different from the model result.

Curtailment increases for the -10% storage capacity scenario and decreases for the +10% storage capacity scenario, which is according to expectations. A smaller German storage implies less total storage capacity in both countries together and thus less capacity to deal with the hours of overpro-

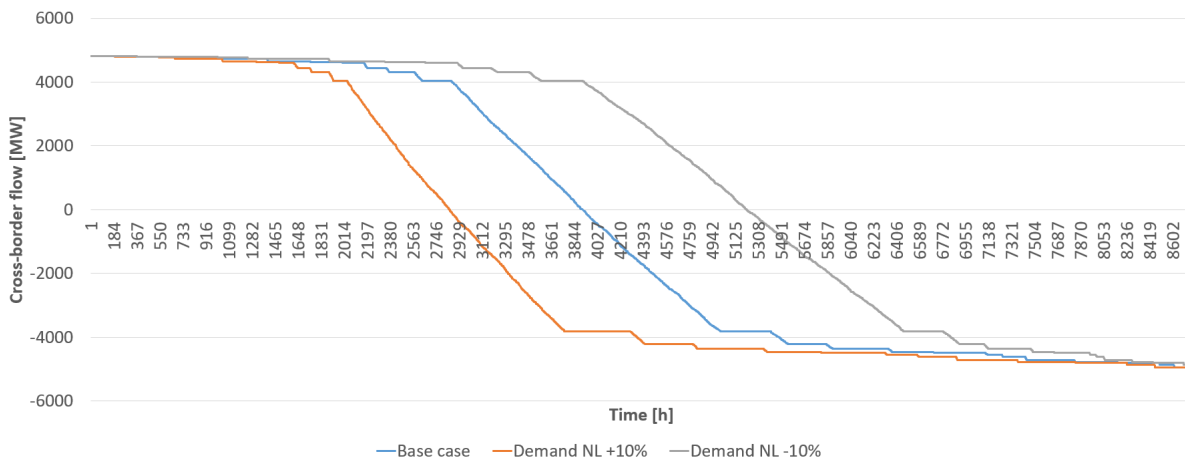


Figure 6.19: Sensitivity of cross-border flows to electricity demand in the Netherlands. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

duction. More hours will thus have to be curtailed. More total storage capacity implies fewer hours that require curtailment. Note that curtailment is not very sensitive to a change in storage capacity.

Hydrogen production is increasing in the -10% storage capacity scenario and decreasing in the +10% storage capacity scenario. This behaviour is as expected as a small storage capacity leads to more low-priced overproduction hours to charge the storage by hydrogen production. On the other hand, a large storage capacity implies less overproduction, fewer low-priced hours and thus lower hydrogen production. Electricity production and hydrogen sale behave according to the same dynamics as explained in Section 6.4.1. However, it is a smaller storage capacity that decreases prices and a larger storage capacity that increases prices, as opposed to the effect of more and less renewable energy.

Figure 6.20 shows the small sensitivity of the cross-border flows to German storage capacity. A smaller German storage capacity leads to more import to the Netherlands, which is expected as the German storage can charge less so there will be more energy to export from Germany to the Netherlands. On the contrary, a larger German storage capacity leads to a little shift in the flow duration curve towards more export hours. Dutch overproduction is then stored in the German storage.

Table 6.6: Sensitivities to +/- 10% storage capacity in Germany.

Performance indicator	-10% Storage capacity	Base case	+10% Storage capacity
Annual dispatch cost	-0.66%	€5.08bn	-1.80%
Curtailment	+1.05%	1051h	-0.57%
Hydrogen production	+1.85%	16585863 MWh	-1.73%
Electricity production	+2.43%	1062908 MWh	-26.49%
Hydrogen sale	+3.82%	15028986 MWh	+1.09%

6.5. Conclusions

This chapter discussed the verification and validation of the storage function and the implementation thereof in Powerflex. Verification of the storage function has been performed by three tests, namely debugging, extreme value analysis and boundary analysis. These tests showed that the function is implemented according to the conceptual design; the price responsive behaviour of the storage could be explained in all cases and no errors occurred in the function. Note that the storage response to negative electricity prices might seem counter intuitive. For the extreme value analysis with an electricity price of -10000 €/MWh, the storage charges continuously as charging at a negative electricity price lowers the costs maximally: charging even leads to revenues for the storage.

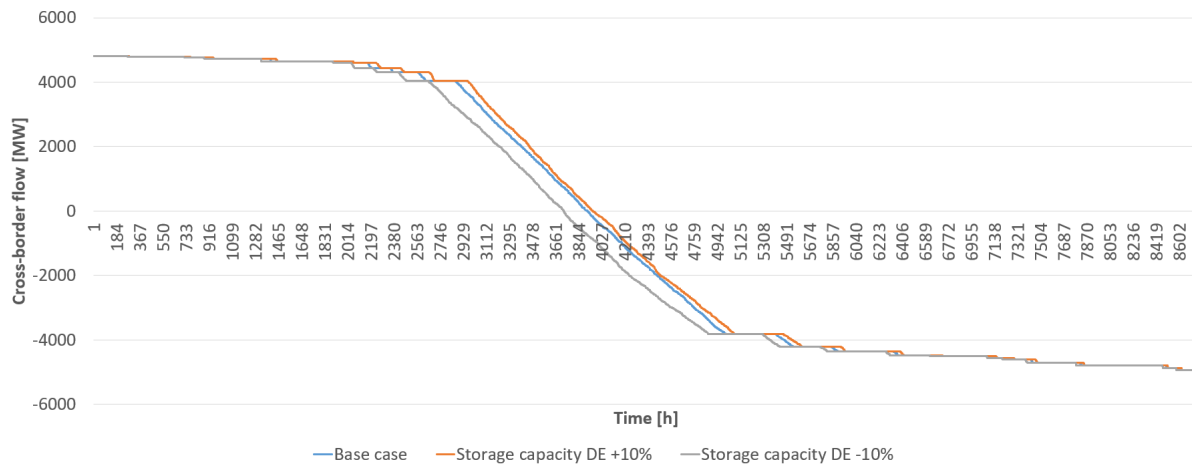


Figure 6.20: Sensitivity of cross-border flows to the storage capacity in Germany. A negative power transfer represents import and a positive power transfer represents export as seen from the Netherlands.

The section on model convergence discusses several manners in which it has been tried to achieve model convergence. However, this was not successful and it can be concluded that the model convergence issues are caused by a large share of variable renewable energy capacity in combination with insufficient availability of flexible capacity. The convergence issues lead to very negative prices in the model and this will be seen as a model artefact throughout the rest of this thesis. The very negative electricity prices and the storage price responsive behaviour in case of such prices is likely to lead to odd model results. This should be taken into account in the discussion of the results. It should be noted that results from non-converging scenarios cannot be considered valid as the model does not find a solution in these runs.

From operational validation of the storage function in isolation, it could be concluded that the storage function shows the behaviour that can be expected. The storage responds to prices as expected and stays within the limits of its charging, discharging and energy capacities. Operational validation of the implementation of the storage function in Powerflex also showed expected behaviour. The presence of storage removes price extremes from the model. Moreover, more storage in the Dutch system leads to more import of electricity to the Netherlands as the Dutch storage will also receive part of the German overproduction in that situation.

However, operational validation of the implementation of the storage function in Powerflex revealed certain unexpected outcomes. It was found that a negative residual demand mostly corresponds to positive electricity prices, even though the residual demand was corrected for charging and discharging of the storage and cross-border flows. Moreover, during validation of the model it was found that the costs of producers are higher than the revenues. This should imply that none of the producers is willing to supply, however they do supply in the model runs.

Finally, a sensitivity analysis was performed by varying the Dutch electricity demand, the Dutch variable production of wind, solar and combined wind and solar installed capacities and the German storage capacity. Quite some asymmetric shifts in output variables were noted even though the inputs were varied in a symmetric manner with +10% and -10%. The sensitivity analysis showed that Powerflex is sensitive to wind energy production. Moreover, dispatch costs increase for both an increase and a decrease in wind energy production, which is an unexpected result. This issue may be related to the odd results regarding the producer costs in Powerflex. Another possible reason for the odd results in the sensitivity analysis may be that a one-at-a-time sensitivity analysis has been performed in this thesis, while a multivariate sensitivity analysis would be needed in case of interaction effects between input variables. It is left for further research whether Powerflex is a linear model and whether a multivariate sensitivity analysis is needed.

7

Results

This chapter presents the modelled scenarios, its data and corresponding results. Firstly, the scenario design will be discussed and the scenario data will be described, including some backgrounds about the assumptions in the hydrogen market. The remaining part of the chapter objectively presents the results grouped per performance indicator related to the electricity market, namely average dispatch costs, annual dispatch costs, price duration curves and curtailment. The deployment of interconnection and storage capacity are shown in the flow duration curves and storage utilisation plots respectively.

7.1. Scenario design

The aim of the research in this thesis is to show the system effects of cross-border transmission capacity and seasonal storage on the future Dutch power system with a large share of wind. The scenarios should thus contain a small and large cross-border transmission capacity and storage capacity and combinations of these in order to show the difference in system benefits of both options. Seven scenarios have been designed with combinations of large Dutch storage capacity, small Dutch storage capacity, large interconnection capacity, mid-sized interconnection capacity and small interconnection capacity. An overview of the scenarios is given in Figure 7.3. A base case scenario is defined with a mid-sized storage capacity and mid-sized interconnection capacity.

The storage capacity in each country is based on the maximum negative residual demand in each country. This method was based on the method in Afman and Rooijers (2017). The Dutch storage capacity is varied at 25 %, 50% and 75 % of the maximum negative residual demand in the model. The maximum negative residual demand in the Netherlands is 15 GW in the model, as can be seen from Figure 7.1. Table 7.2 shows an overview of the installed storage capacities representing 25%, 50% and 75% storage in the Netherlands. The German storage capacity is kept constant at 50% of the maximum negative residual demand in Germany in the model. The maximum negative residual demand in Germany is 80 GW in the model, see Figure 7.2. German charging and discharging capacity is 40GW and an energy capacity of 9732.36 GWh is used in all scenarios.

Table 7.1: Installed storage capacities representing 25%, 50% and 75% storage in the Netherlands.

	25% Storage	50% Storage	75% Storage
Charging capacity [GW]	3.75	7.5	11.25
Energy storage capacity [GWh]	911.04	1824.27	2737.50
Discharging capacity [GW]	3.75	7.5	11.25

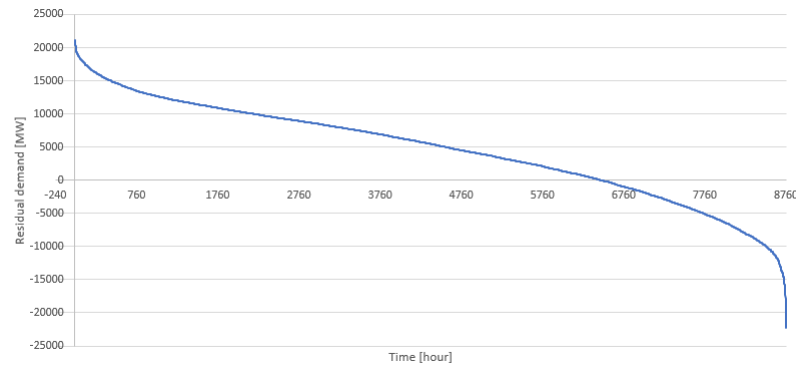


Figure 7.1: Residual demand curve of the Netherlands

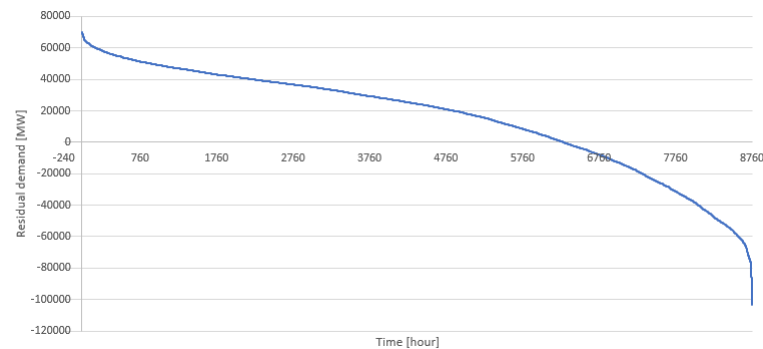


Figure 7.2: Residual demand curve of Germany

Currently, cross-border transmission capacity between the Netherlands and Germany is nearly 4250 MW, including new transmission line between Doetinchem in the Netherlands and Wesel in Germany which became operational in 2018 (TenneT, 2019). TenneT expects an interconnection capacity of 5 GW between the Netherlands and Germany by 2030 (Schoots and Hammingh, 2015). Therefore an interconnection capacity of 5 GW has been chosen as base case. The interconnection capacity is varied with +/- 25 % around this 5 GW.

7.1.1. Description of scenario data

Scenario data of the Power to Ammonia (P2A) study by CE Delft is used. In this study, scenarios were designed to assess the business case of P2A, which is also a flexibility option in the Dutch power system. The study contains scenarios for the Dutch and German power system for three different years (2020, 2023, 2030), based on the Dutch and German national outlooks. Additional scenarios with adjustments to fuel prices and RES capacity were added to the study as these are considered relevant uncertainties for the P2A business case.

However, for this research it was chosen to use the 2030 scenario for the Dutch and German power system without the additional adjustments for the P2A business case. In this way, the scenario contains baseline data of the Dutch and German national outlooks which is then again adjusted to make it suitable for the goal of this study.

The National Energy Outlook 2015 (NEO) is used as a baseline of the Dutch scenario. The NEO is published yearly by ECN and PBL and provides insights into developments in the Dutch energy system in an international context. It contains two pathways to 2030, namely a fixed policy and a fixed and intended policy. The fixed pathway contains the fixed policies from 2015 on. The fixed and intended policy also contains these fixed policies but additionally covers the intended policies on the national and European level in order to achieve a larger decarbonisation in 2030. The German baseline data is taken from their Grid Development Plan (Netzentwicklungsplan).

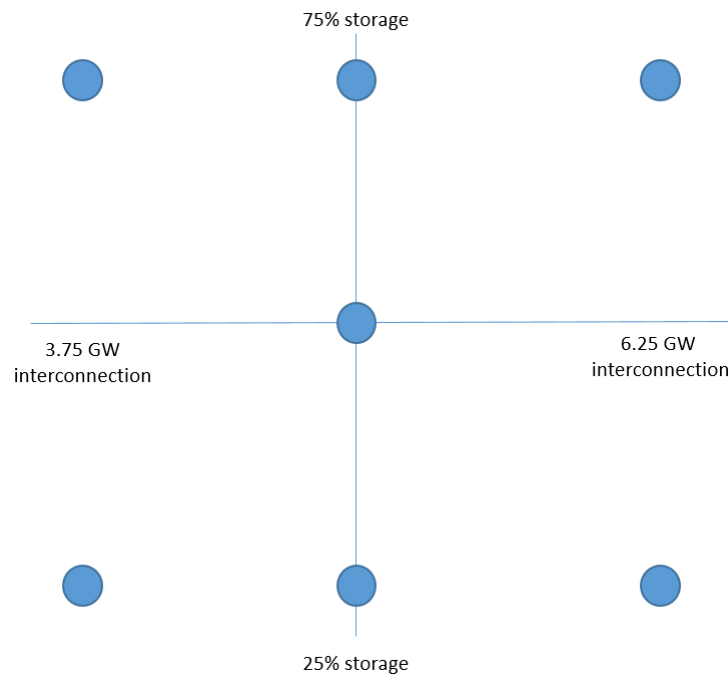


Figure 7.3: An overview of the scenarios used for the scenario analysis. The blue dots indicate a scenario.

Baseline data covers data about electricity demand projections, fuel prices and total installed capacities of wind, solar, thermal plants and pumped hydro storage plants in each country. There are nine categories of thermal plants, namely coal, blast furnace gas, natural gas, lignite, biomass, geothermal, oil and waste incineration plants. It is assumed that there will be no nuclear power plants in the Netherlands and Germany in 2030. Moreover, it is assumed that Dutch coal plants are phased out by 2030.

Technical characteristics and capacity per power plant are taken from CE Delft's proprietary data set. This data set contains detailed information about the number of units that a power plant consists of, cold and warm start up cost, cold and warm start up time, minimum on time, minimum off time, monthly availability and whether a unit is a must run unit or not. The start date and end date of a power plant indicate the opening date and expected closure date of the power plant respectively. Assumptions are made when certain data about a power plant is unavailable. Assumptions for heat rate curves are used to define a power plant's output.

Demand, wind and solar generation have hourly profiles in order to capture the weather-dependent seasonal, weekly and day and night patterns. These hourly profiles are made by scaling the capacities on historic production data, for which the year 2013 is used. A distinction has been made between onshore and offshore wind production and these profiles together form the wind power production profile in a country.

Table 7.2 shows the installed renewable energy capacities that are assumed in the model runs. The most optimistic but realistic renewable capacities are selected per country. The German capacities are taken from ENTSO-E's Vision 4 scenario, whereas the Dutch wind energy capacities are taken from the NEV and the solar PV capacity from TKI.

Table 7.2: Installed renewable capacities per country

	Capacity in the Netherlands [GW]	Capacity in Germany [GW]
Offshore wind	11.5	23.6
Onshore wind	8	89.5
Solar PV	20	68.8

7.1.2. Hydrogen price data

As explained in Chapter 4, the hydrogen price in the model is based on the production costs of hydrogen through SMR. For including the hydrogen price in Powerflex, the higher heating value (HHV) and lower heating value (LHV) have been taken into account. This section contains more information about the assumptions behind the hydrogen price in Powerflex.

When fossil fuels are burnt, oxygen in the air combines with carbon and hydrogen and this produces carbon dioxide and water. A part of the energy transforms the water into steam while burning the fossil fuel and this energy is usually lost. The HHV is the total amount of heat that is released when a fuel is burnt. It includes the amount of energy that is used for transforming water into steam and thus assumes that the heat contained in this water is recovered. The LHV does not include the energy that is used for transforming the water into steam and thus represents the heat energy that can be used when a fuel is burnt. Powerflex calculates with fuel prices in [€/MWh LHV] as these represent the amount of energy that can be used for electricity generation after burning the fossil fuel.

Formula 7.1 links the price of natural gas to the production costs of hydrogen based on SMR (Raine et al., 2009). This formula assumes a natural gas price of 7.25 €/GJ and an electricity price of 66 €/MWh (18.37 €/GJ). Additional assumptions about the SMR technology behind this formula are shown in Table 7.4.

$$P_{H_2}[\text{€/kgHHV}] = 0.187 * P_{NG}[\text{€/GJLHV}] + 0.226 \quad (7.1)$$

Rewriting formula 7.1 into a formula with the natural gas price in [€/MWh LLV] and the hydrogen price in [€/MWh HHV] gives formula 7.2.

$$P_{H_2}[\text{€/MWh}] = \frac{0.187}{3.6 * 0.039} * P_{NG}[\text{€/MWh}] + \frac{0.226}{0.039} \quad (7.2)$$

In an additional step in Powerflex, this hydrogen price in [€/MWh HHV] is transformed into [€/MWh LHV] by using the LHV of hydrogen given in Table 7.3. The hydrogen price follows the seasonal pattern as shown in Figure 7.4.

Table 7.3: Higher heating value and lower heating value of hydrogen

	Higher heating value [MJ/kg]	Lower heating value [MJ/kg]
Hydrogen	141.8	120.0

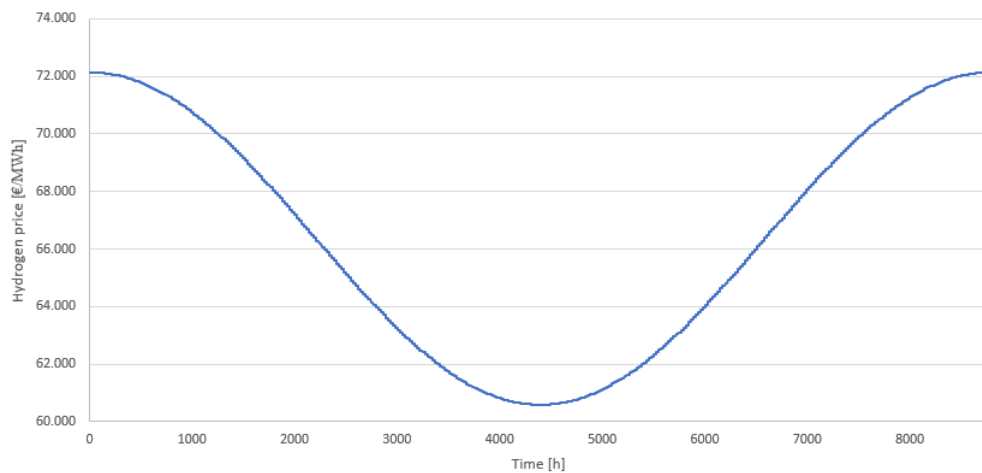


Figure 7.4: Hydrogen price used as input for the model

Table 7.4: Economic data for hydrogen production through steam reforming of natural gas (Raine et al., 2009)

Capacity	45300 tons/year of hydrogen
Charge	Approximately 900 GJ/h of natural gas (in reactor and as fuel for auxiliary power)
Investment	75 million €
Fixed costs (maintenance, workers and other)	330 € / h
Consumptions	- Electricity 1500 kWh/h - Catalyzer 66 €/h
Efficiency	H_2 / natural gas = 72% based on LHV
CO₂ emissions	Approximately 9.3 tons of CO ₂
Production cost	Approximately 1.6 €/kg (or 13.4 €/GJ) for a project life reaching 15 years

7.2. Scenario results per KPI

This section displays the results of the scenarios specified per KPI.

7.2.1. Dispatch costs

Average dispatch costs

Figure 7.5 and 7.6 show the average dispatch cost in the Netherlands and Germany respectively. The average dispatch cost per country shows how price convergence in both countries is influenced by the storage and interconnector capacity. In all scenarios, average dispatch cost in the Netherlands is at least 6.5 €/MWh higher than the average dispatch cost in Germany.

Scenarios with equal interconnector capacity but different storage capacity show that more storage leads to a reduction in average dispatch cost of approximately 3 €/MWh in the Netherlands (see Figure 7.5). On the contrary, a larger interconnector capacity increases the average dispatch cost in all scenarios, although the increase is not large. The increase in average dispatch cost is larger for scenarios with 75% storage than for scenarios with 25% storage.

There is a small difference in average dispatch cost in Germany between the scenarios (see Figure 7.6). Larger cross-border transmission capacity leads to lower average dispatch cost in Germany. Contrarily, larger storage capacity increases the average dispatch cost in Germany as shown by scenarios with equal interconnection capacity but increasing storage capacity.

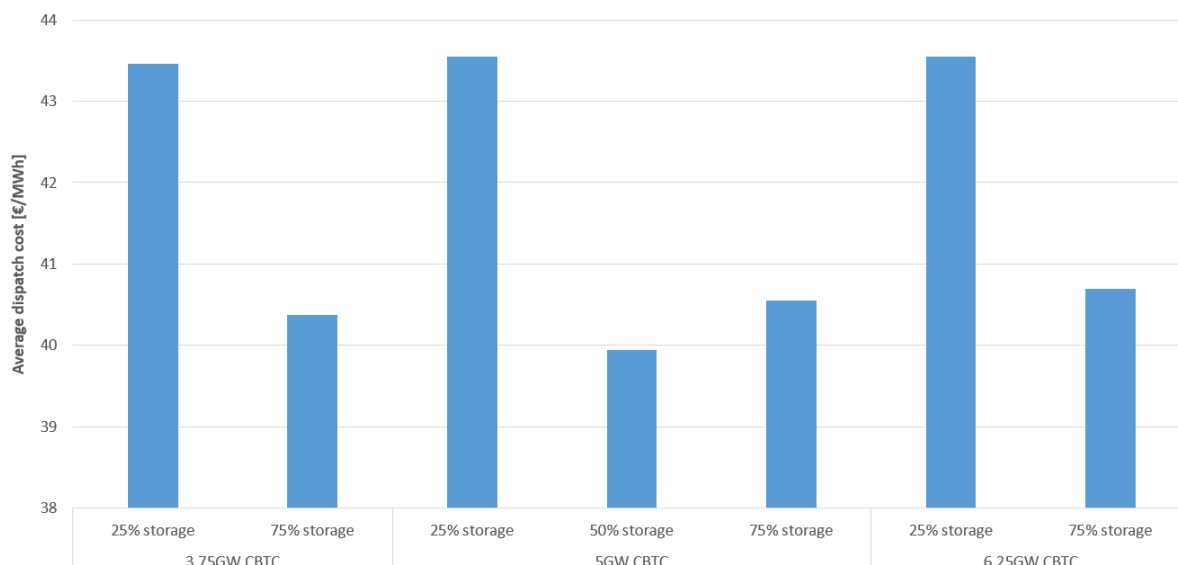


Figure 7.5: Average dispatch cost per scenario in the Netherlands

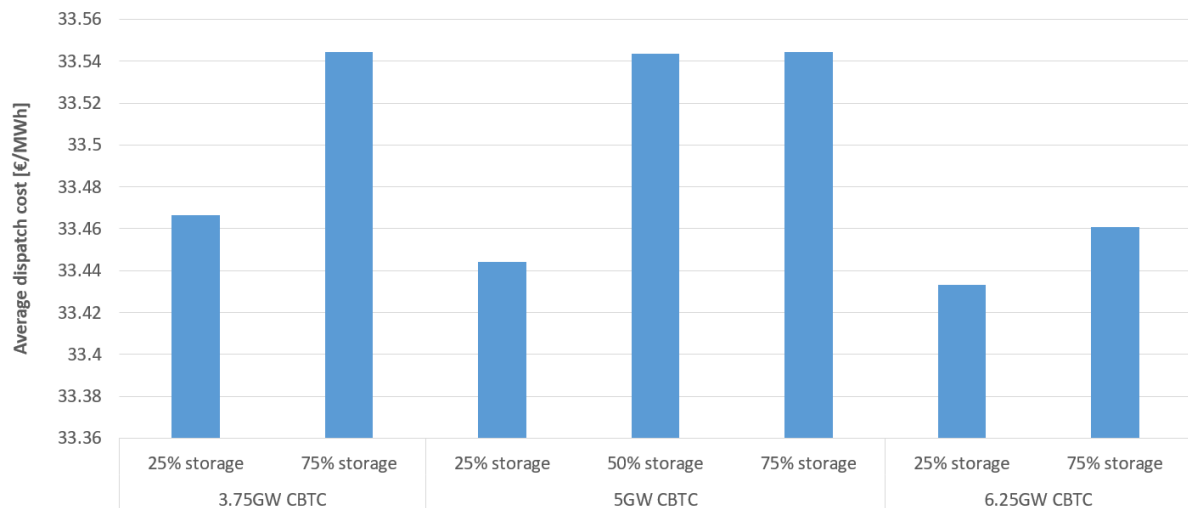


Figure 7.6: Average dispatch cost per scenario in Germany

Annual dispatch costs

Figure 7.7, 7.8 and 7.9 show the annual dispatch cost in the Netherlands, Germany and in both countries in total respectively. The latter figure shows how the annual dispatch cost is optimised for both countries while the Dutch annual dispatch cost shows the situation in the Netherlands specifically.

A larger storage capacity reduces the annual dispatch cost in the Netherlands with approximately 1.5 billion euro (see Figure 7.7), whereas a larger interconnection capacity does not have a large influence. A larger interconnection capacity even slightly increases the annual dispatch costs in most scenarios. The annual dispatch costs in Germany are nearly constant among the scenarios (see Figure 7.8).

Figure 7.9 shows that the annual dispatch cost in both countries is lower when either storage capacity is larger or interconnection capacity is larger or both capacities are larger.

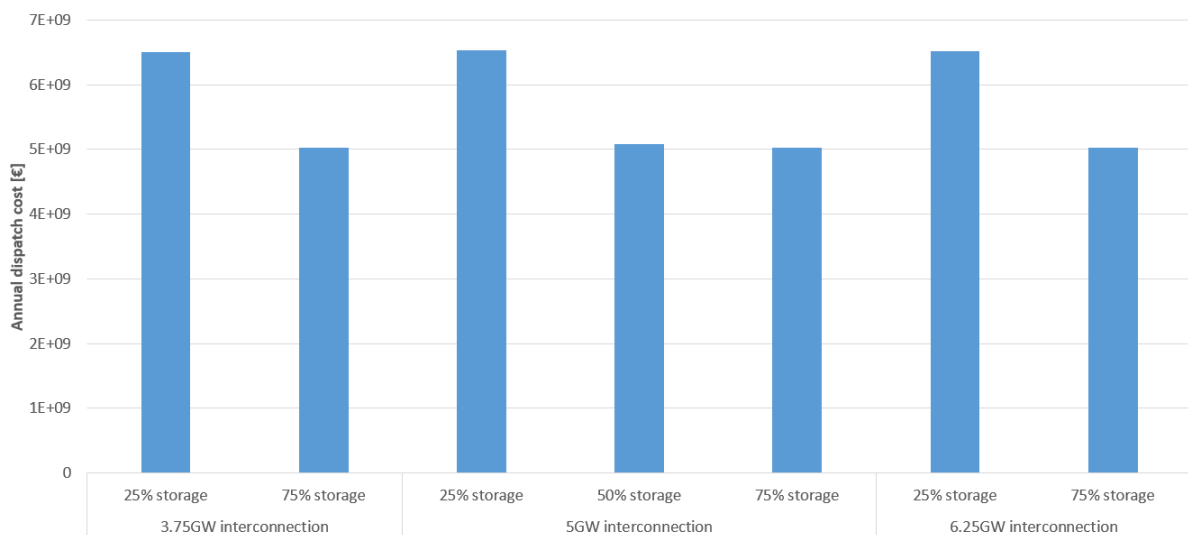


Figure 7.7: Annual dispatch cost per scenario in the Netherlands

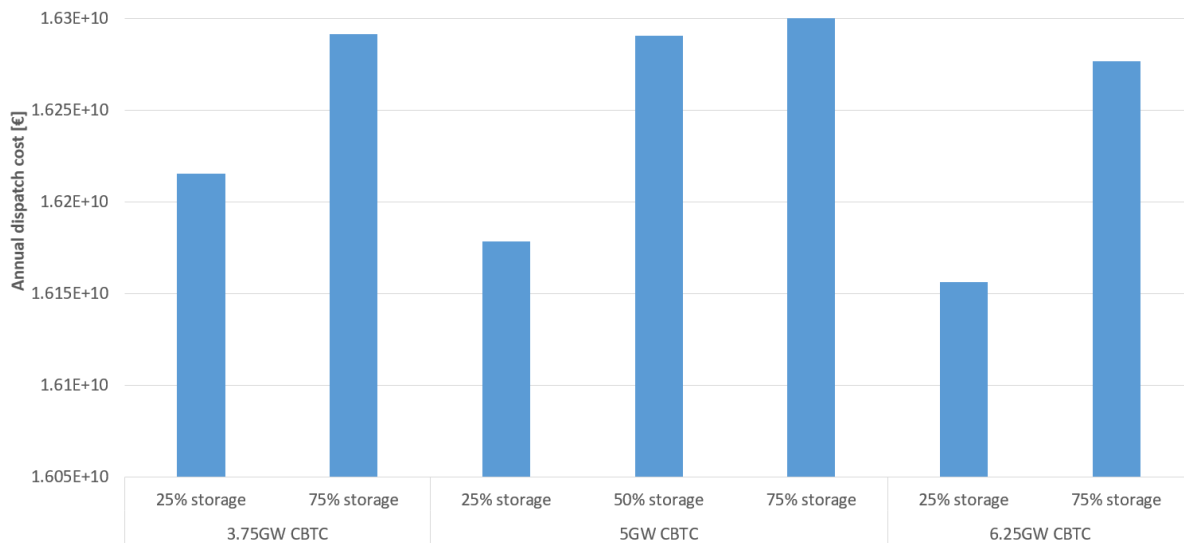


Figure 7.8: Annual dispatch cost per scenario in Germany

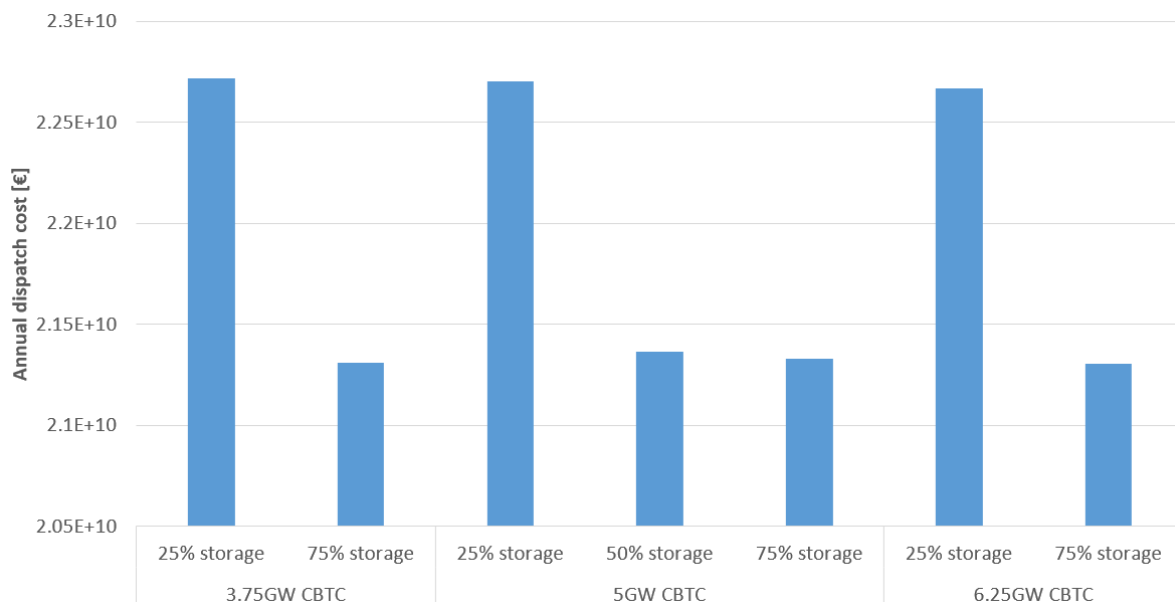


Figure 7.9: Total annual dispatch cost per scenario in both countries

7.2.2. Price duration curves

The price duration curves of the Netherlands and Germany are shown in Figures 7.10 and 7.11 respectively. The price duration curves in Germany show not much influence of either a varying storage capacity or a varying interconnection capacity, whereas the curves in the Netherlands do show some effects.

A larger storage capacity leads to fewer electricity price extremes in the Netherlands. Especially the negative prices are dampened when a larger storage capacity is present. However, the price effects are more pronounced between scenarios with 25% and 50% storage than between scenarios with 50% and 75% storage. In other words, the effect of a larger storage capacity becomes smaller when the storage capacity is already considerably large.

A larger interconnection capacity has only a small effect on the electricity prices. The price duration

curves for scenarios with equal storage capacity but different interconnection capacity show large overlap. The influence of larger interconnection capacity is slightly larger for scenarios with 25% storage than for scenarios with 75% storage.

Generally, increased interconnection capacity and increased storage capacity both lead to less extreme prices. However, increased storage capacity has a much larger effect and this effect is more pronounced in the Netherlands than in Germany.

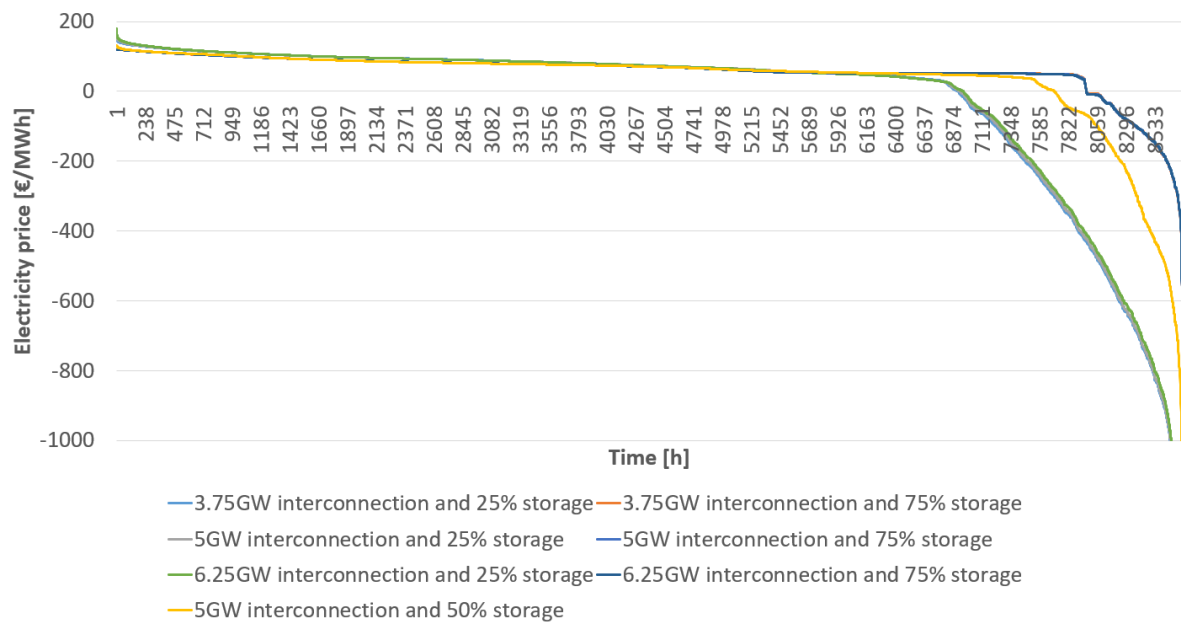


Figure 7.10: Price duration curves of the Netherlands

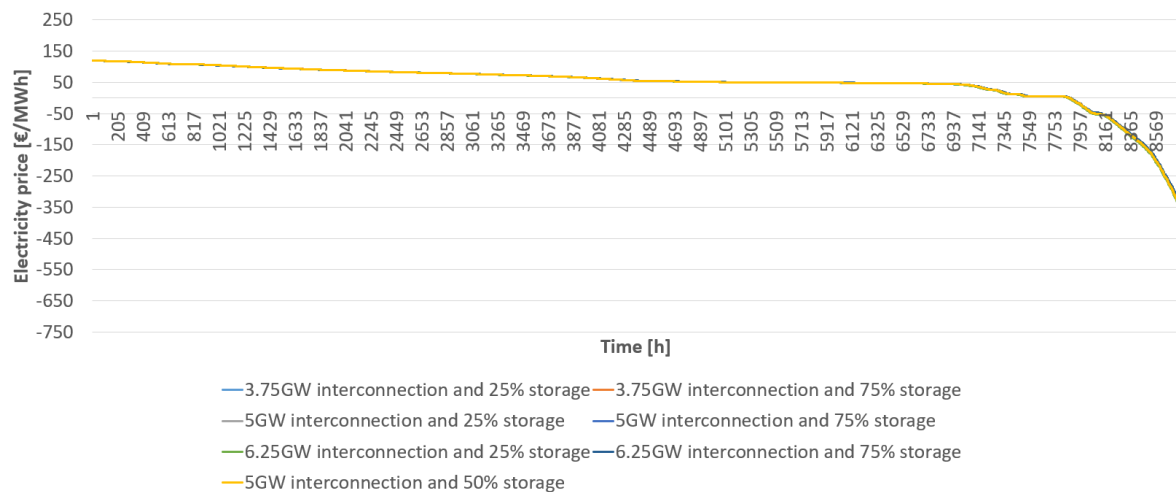


Figure 7.11: Price duration curves of Germany

7.2.3. Curtailment

Figures 7.12 and 7.13 show the curtailment needs defined as the annual curtailment hours for the Netherlands and Germany. Note that the vertical axis in Figure 7.13 for Germany starts at 865 hours and not at 0 hours.

A larger storage capacity reduces the curtailment needs in the Netherlands and Germany. The curtailment needs in the Netherlands are larger than curtailment in Germany for scenarios with 25% and 50% storage. Additional interconnection capacity also reduces the hours of curtailment in the Netherlands. This effect is more pronounced for increasing interconnection capacity with 25% storage than with 75% storage. This could indicate a saturation point: a point at which either more interconnection capacity or more storage capacity in itself does not longer contribute to a reduction of curtailment.

Furthermore, the total number of curtailment hours in Germany is larger for scenarios with large interconnection capacity and 25% storage. More renewable energy is transmitted from the Netherlands to Germany in these scenarios.

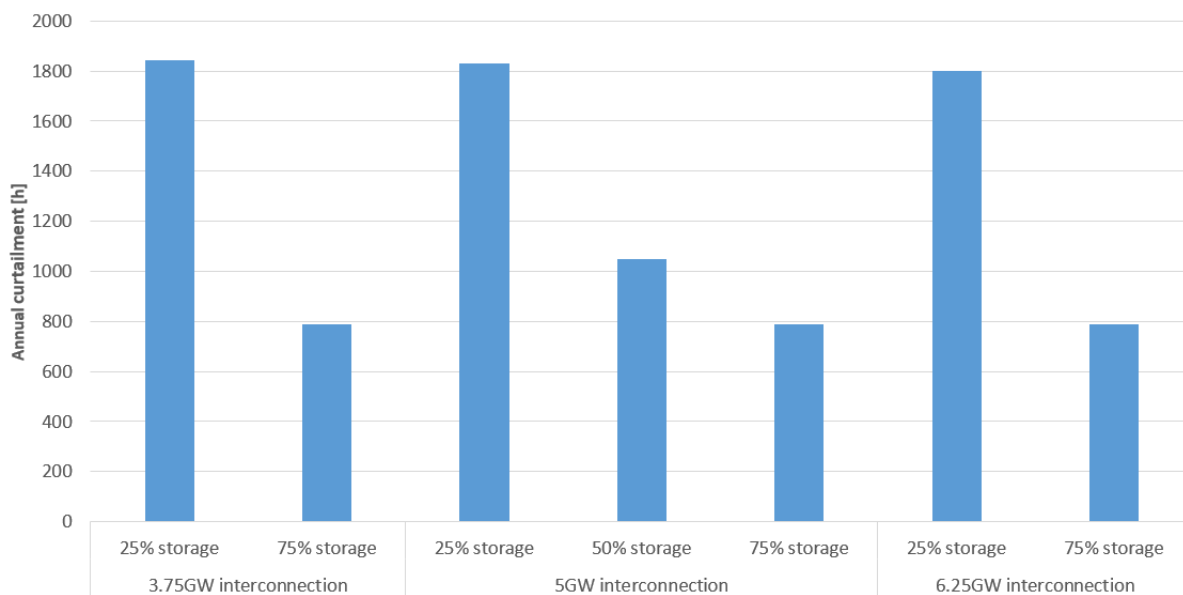


Figure 7.12: Annual curtailment per scenario in the Netherlands

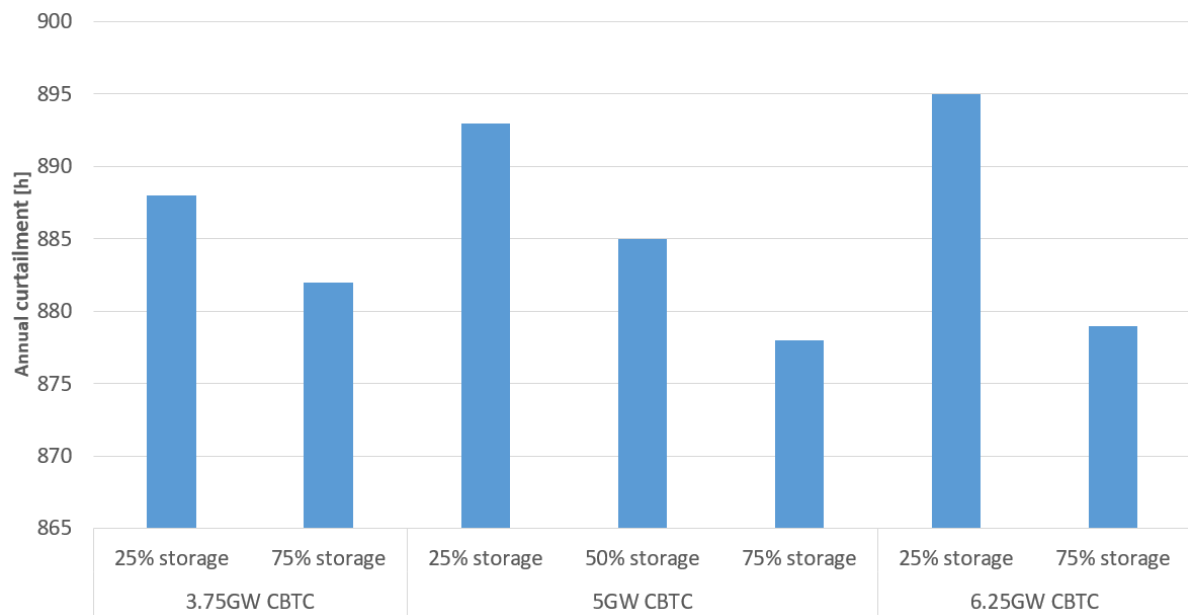


Figure 7.13: Annual curtailment per scenario in Germany. Note that the vertical axis starts at 865h and not at 0h.

7.2.4. Flow duration curves

Figure 7.14 shows the flow duration curves per scenario, with regard to the Netherlands. A negative power transfer means that electricity is imported from Germany to the Netherlands. A positive power transfer means that electricity is exported from the Netherlands to Germany.

The flow duration curves are grouped per storage capacity. A larger storage capacity leads to more electricity import, which is indicated by a shift to the left of the flow duration curves for 75% storage capacity. The flow duration curves of scenarios with 25% storage capacity are located more to the right, which means that more electricity is exported than imported. A larger storage capacity thus leads to more electricity import, but this is not a linear effect: the shift between 25% and 50% storage is larger than the shift between 50% and 75% storage.

Moreover, the flow duration curves are steeper and more horizontal for scenarios with large storage than for scenarios with small storage. This indicates that a large storage capacity leads to more hours of full use of available interconnection capacity.

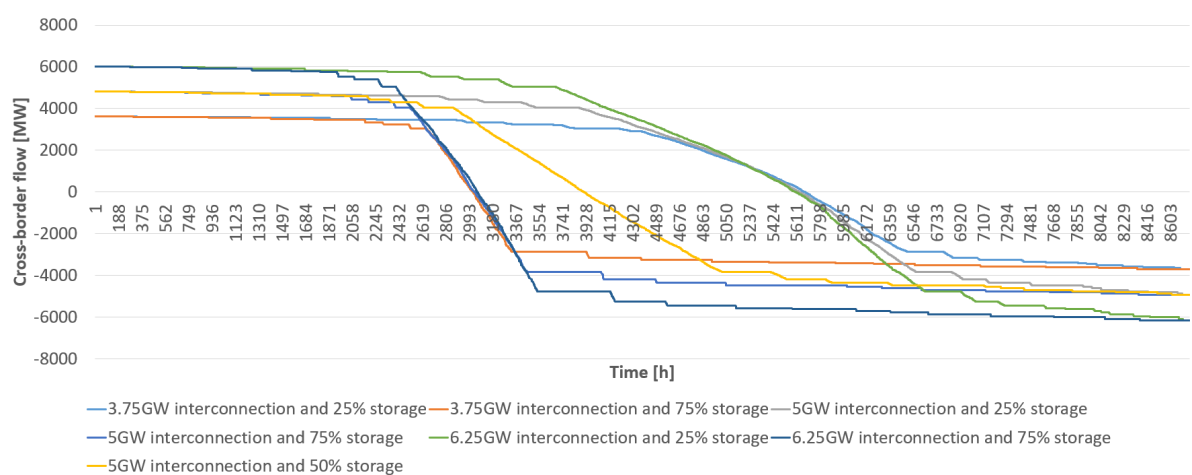


Figure 7.14: Flow duration curves per scenario for the Netherlands. A negative power transfer means that electricity is imported from Germany to the Netherlands. A positive power transfer means that electricity is exported from the Netherlands to Germany.

7.2.5. Storage utilisation

Electricity storage normally performs closed storage cycles to make profit out of the price differences between charging electricity at low electricity prices and discharging at high prices. This means that all energy that is charged when production is high and demand is low will be discharged when production is low and demand is high. However, the hydrogen storage modelled in this study has the option to sell hydrogen in the hydrogen market as well. The storage cycle of the hydrogen storage is thus not closed.

Figures 7.15 and 7.16 show the utilisation of the storage capacity per scenario in two different ways. Figure 7.15 gives the utilisation in terms of tank capacity: the number of times that the tank capacity is utilised for electricity sale and hydrogen sale and which part of the tank capacity is filled with remaining energy at the end of the run. Figure 7.16 displays the utilisation in terms of energy capacity: how much energy of total charged energy is sold as electricity, how much is sold as hydrogen and how much energy remains in the storage at the end of a run.

A small storage charges more often than a large storage in the Netherlands. The tank capacity in 25% storage scenarios is filled eleven times, whereas this is only seven times in scenarios with 75% storage. The charged energy capacity is nearly twice as much in scenarios with 75% storage than in scenarios with 25% storage.

A larger interconnection capacity does not have an influence on the storage utilisation in the Netherlands. However, looking at the results in Germany showed that hydrogen sale decreases in Germany when cross-border transmission capacity is increased. German storage is also utilised to a lesser extent in general. This can indicate that the Dutch storage can deal better with overproduction hours in the Dutch power system.

Scenarios with 25% storage show a larger need for discharging through electricity sale than scenarios with 75% storage. The storage size also influences the hydrogen sale in the Netherlands: a larger storage sells more hydrogen. The number of times that the tank capacity is utilised for hydrogen sale is 8 times in scenarios with 25% storage, whereas this is 6.5 times when 75% storage is available. However, the hydrogen sale in 75% storage scenarios in terms of energy is almost 10 TWh larger than the hydrogen sale of a 25% storage.

The remainder in the storage at the end of a run is the result of a model artefact. Under normal electricity prices, the storage would be empty at the end of a run as all energy should be sold to obtain the highest profit. However, the remainder in the hydrogen storage at the end of the year implies that more energy has been charged than discharged. Powerflex calculates extremely negative prices when the system is not sufficiently able to deal with overproduction hours. The aim of the storage function is to minimise costs. Negative electricity prices imply that charging also lowers the cost of the storage. Thus, it has cost minimising effects for the storage to charge more than it discharges in such scenarios. In reality such very negative electricity prices will not exist and most often, negative electricity prices will not exist at all.

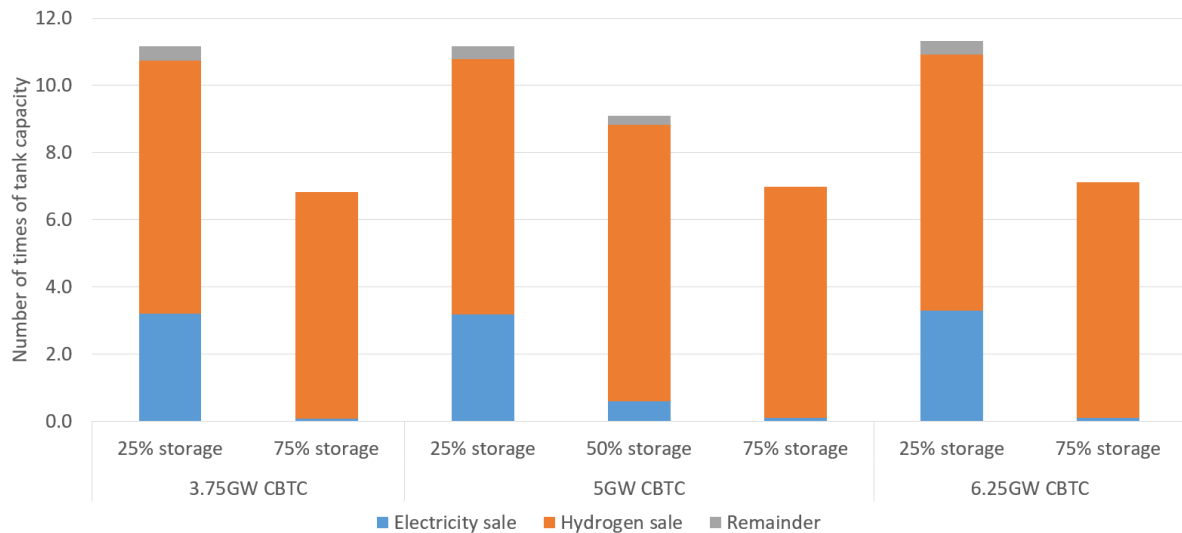


Figure 7.15: Utilisation of Dutch storage capacity per scenario in terms of tank capacity: the number of times that the tank capacity is utilised for electricity sale and hydrogen sale and which part of the tank capacity is filled with remaining energy at the end of the run.

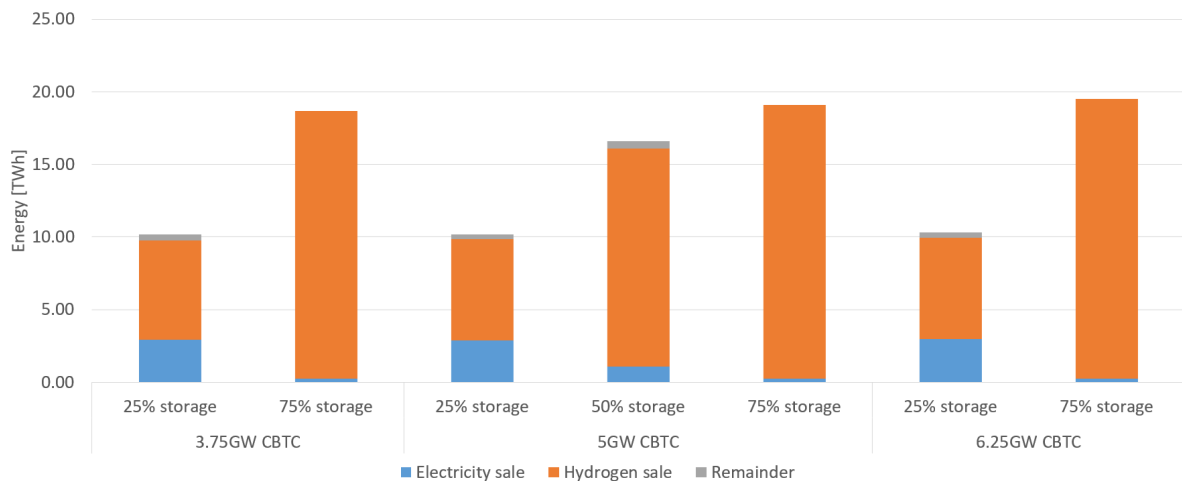


Figure 7.16: Utilisation of Dutch storage capacity per scenario in terms of energy capacity: how much energy in total is sold as electricity, how much energy is sold as hydrogen and how much energy remains in the storage at the end of a run.

7.3. Conclusions

The model results show that the positive effects of enlarging interconnection capacity are small. Both annual and average dispatch costs in the Netherlands increase slightly when the interconnection capacity is enlarged. This increase is larger in scenarios with 75% storage than in scenarios with 25% storage. The model results show that a larger interconnection capacity has more positive effects on the performance indicators when storage capacity is small.

The model results indicate that seasonal storage and cross-border transmission capacity complement each other. The flow duration curves are steeper and more horizontal when storage capacity is large; interconnection capacity is more intensively used when storage is large. The interconnector deployment is influenced by the size of the storage capacity. A larger storage leads to more hours of full utilization of the interconnector capacity. Moreover, a larger storage leads to more electricity import through the interconnector.

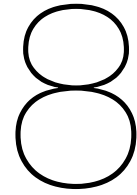
Storage capacity thus increases the need for cross-border transmission capacity in the model results. However, cross-border transmission capacity does not decrease the need for storage capacity,

as the effects of an enlarged interconnection capacity are generally small. A larger interconnection capacity has more positive effects on the performance indicators when storage capacity is small, but the benefits are still small in the model results.

Increasing storage capacity does bring larger benefits to the system than enlarged interconnection capacity does in the model results. The first increase in storage capacity brings the largest benefits to the system and marginal benefits reduce if storage capacity is increased. The model results show saturation effects on the system benefits between 50% storage and 75% storage, despite the interconnection capacity in the scenarios. Put differently, the system benefits between 25% and 50% storage are larger than between 50% and 75% storage, which is another indication that the 75% storage capacity is overdimensioned in the model. In the model results, there is a limit to the system benefits brought by storage capacity and thus a limit to the storage capacity that is required.

In the model results, storage capacities larger than 50% storage are not justifiable as they lead to declining marginal benefits. The results may show inclining and declining benefits summed up into overall inclining benefits, leading to a distorted picture. Nevertheless, from the model results it can be concluded that storage capacity for the Netherlands will be between 25% and 50% storage capacity.

In Chapter 8, the results will be interpreted and the consequences of the results will be discussed per power sector actor.



Discussion

Whereas Chapter 7 objectively presents the model results, this chapter will discuss the results more extensively. This chapter serves to take a step back from the model and its results and to interpret what the results would mean in reality. Firstly, the model results regarding the dispatch costs, complementarity of deployment and the system effects of seasonal storage and interconnection capacity are more elaborately discussed. Secondly, the results are evaluated in the light of previous research. After that the influence of the scope and modelling approach on the results is discussed and limitations to this study are identified. It is explained to what extent the scope and modelling approach influence the results and whether they can be compared to effects that can appear in reality. Finally, practical implications of the model results are discussed, meaning that the results are interpreted for different actors in the power sector.

8.1. Discussion of model results

This section discusses the model results regarding dispatch costs, complementarity of deployment and system effects of seasonal storage and cross-border transmission capacity in more detail.

8.1.1. Influence on dispatch costs

The effects of increased interconnection capacity on annual and average dispatch costs are small in the model results. Both annual and average dispatch costs in the Netherlands increase slightly when interconnection capacity is enlarged in the model. This increase is larger in scenarios with 75% storage than in scenarios with 25% storage, but the effect is nevertheless small.

Regarding the effects of storage capacity, the model results show that average dispatch costs decrease with approximately 3€/MWh between 25% storage and 50% storage in all scenarios, despite the interconnection capacity in that scenario. However, a small increase in average dispatch costs of approximately 0.5€/MWh can be noticed between 50% and 75% storage in all scenarios, despite the interconnection capacity in that particular scenario. Annual dispatch costs are decreased by approximately 1.5 billion euro in all scenarios in the model results when 75% storage is considered instead of 25% storage. Annual dispatch costs are slightly higher if storage capacity is 50% instead of 75% in all scenarios, so again despite the value of interconnection capacity.

8.1.2. Complementary deployment

The interconnector deployment is influenced by the size of the storage capacity in the model results. The flow duration curves are steeper and more horizontal when storage capacity is large; interconnection capacity is more hours fully used when storage is large. From the shifts in the flow duration curves in the model results, it can be seen that a small storage leads to more export than import, as seen from the Dutch system perspective in the model results. On the contrary, a large storage leads to more import than export through the interconnector.

In the scenarios with 25% storage capacity, this means that there are still hours of overproduction and that interconnection capacity helps to export this overproduction to Germany. When storage is large, that is 50% or 75% storage, there are fewer hours of overproduction and the interconnection capacity allows for the use of Dutch storage capacity to Germany. There are more hours of import so the German overproduction is stored in the Dutch storage. This indicates that interconnection capacity helps to sell Dutch storage capacity in Germany in the model results.

The shift in the flow duration curves is less pronounced between 50% and 75% storage than between 25% and 50% storage in the model results. Still, a larger storage leads to more import than export and to more hours of full use of interconnection capacity, even though a 75% storage capacity influences this to a lesser extent than a 50% storage capacity.

Storage capacity thus increases the need for cross-border transmission capacity in the model results. However, cross-border transmission capacity does not decrease the need for storage capacity, as an enlarged interconnection capacity hardly has any effect on storage deployment. Storage capacity thus complements (increases the need for) interconnection capacity, while interconnection capacity does not influence the need for storage capacity.

8.1.3. System effects of storage and interconnection capacity

Generally, enlarging interconnection capacity has minor positive effects on the performance indicators in the model results. The results show that an increased interconnection capacity has more positive effects on the performance indicators in scenarios with 25% storage capacity than in scenarios with larger capacities, but the positive effects are nevertheless small.

Increasing interconnection capacity only has a minor effect on electricity price extremes in the Netherlands. Only a small shift in the price duration curves can be noticed and this shift is slightly larger when storage is 25% than when storage is 75%. A similar effect can be noticed regarding Dutch curtailment needs. The number of curtailed hours in a year decreases for larger interconnection capacity. This effect is more pronounced when storage capacity is small.

The less pronounced effect of increased interconnection capacity when storage is large could be caused by the price effects induced by the storage. A large storage removes price extremes and reduces price differences more than a small storage does. In this study, that implies that electricity prices between the Netherlands and Germany are less different, which can also be seen from the difference in average dispatch costs between the countries. A smaller price difference leads to a lower demand for cross-border transmission capacity and less system benefits caused by enlarged interconnection.

This effect of storage on the electricity prices can be seen in the price duration curves. Regarding the price extremes in the price duration curve, saturation effects are visible as the shift in the price duration curves towards fewer negative prices is larger between 25% and 50% storage than between 50% and 75% storage. A 75% storage capacity thus still influences the price extremes in the Netherlands, though the effects are relatively small. Similarly, despite the interconnection capacity, fewer hours of curtailment occur in scenarios with 75% storage than in the scenario with 50% storage. However, this difference is again relatively small as there are 800 less curtailed hours when the 50% storage scenario is compared with the 25% storage scenarios. Increasing storage capacity from 50% to 75% storage leads to a relatively small reduction of an additional 200 curtailed hours.

An available storage capacity of 75% thus shows an effect on all performance indicators in the model, but this effect is dampened when compared to effects in the scenario with 50% storage. In the model results, the first increase in storage capacity brings the largest benefits to the system and marginal benefits reduce if storage capacity is increased. The results show saturation effects on the system benefits between 50% storage and 75% storage, despite the interconnection capacity in the scenarios. Put differently, the system benefits between 25% and 50% storage are larger than between 50% and 75% storage, which is another indication that the 75% storage capacity is overdimensioned. There is a limit to the system benefits brought by storage capacity and thus a limit to the storage capacity that is required.

8.2. Literature comparison

The positive effects of enlarging the interconnection capacity are found to be minor in the model results in this thesis. This is different from the results in the study by Brancucci Martínez-Anido et al. (2013), who found a relatively large positive influence of cross-border transmission capacity, especially when prices between countries differ much. Opposite to the increasing annual dispatch costs in the model results in this thesis, they found that increasing cross-border transmission capacity lowers annual dispatch costs due to an improved interconnection between countries. Annual dispatch costs are reduced even more when the share of RES is large. In another related study of the same authors (Brancucci Martínez-Anido and De Vries, 2013) they also conclude that a larger interconnection capacity reduces curtailment needs considerably. In the model results in this thesis, curtailment needs decrease only slightly.

Brancucci Martínez-Anido et al. (2013) and Brancucci Martínez-Anido and De Vries (2013) are based on the same cost-minimising dispatch model EUPowerDispatch, including 32 European countries with an hourly resolution for a given year. The model assumes full knowledge, which is the same as in Powerflex. However, Powerflex assumes a smaller scope with only the Netherlands and Germany which can have a negative influence on the system benefits of cross-border transmission capacity. The weather patterns in the Netherlands and Germany are relatively similar as both countries are close to each other. A spatial shift of RES overproduction hours between the Netherlands and Germany will thus lead to fewer system benefits as compared to a spatial shift between the Netherlands and Spain, whose weather patterns and RES potential are different.

Another difference between Powerflex and EUPowerDispatch is that the installed RES capacities in the study for this thesis have deliberately been made very large, especially regarding the installed wind power capacity. This will make the influence of the limited scope in Powerflex even larger, as the effects of similar wind and solar generation patterns are more pronounced. It is thus explainable that the positive effects of enlarging interconnection capacity are smaller in this thesis than in the studies by Brancucci Martínez-Anido et al. (2013) and Brancucci Martínez-Anido and De Vries (2013).

This difference in benefits of increasing cross-border transmission capacity also leads to a difference in complementarity of technologies in the results. The study by Brancucci Martínez-Anido and De Vries (2013) concludes that pumped hydro storage increases the need for cross-border transmission capacity, whereas cross-border transmission capacity decreases the need for pumped hydro storage. Verzijlbergh et al. (2014) come to a similar conclusion but then for controlled EV charging and interconnection capacity. On the contrary, the model results in this thesis show that storage capacity complements (increases the need for) interconnection, whereas interconnection does not affect storage deployment and the need for storage.

Both studies use the EUPowerDispatch model and the difference in complementarity results can originate from whether interconnection capacity does or does not bring benefits to the system. If interconnection capacity does not benefit the system much, it cannot decrease the need for storage while obtaining the same benefits as come from storage capacity. Still, interconnection capacity is needed to transport electricity to the storage, like in the model results in this thesis.

When it comes to the system effects of storage, the model results in this thesis show that the first addition of storage capacity brings the largest benefits to the system and marginal benefits reduce if storage capacity is increased. The extensive literature review by Blanco and Faaij (2018) states that this phenomenon has been repeatedly found in other researches as well. Most of these studies analyse the power sector and do not make a division between daily and seasonal storage.

Generally, the researches conclude that required storage capacity is small (Blanco and Faaij, 2018). High penetrations up to 90% of variable renewable energy only require a storage capacity of at most 1.5% of the system demand. Moreover, the researches state that even if an increase in storage capacity leads to an investment cost reduction, investing more in storage capacity cannot be justified due to the declining benefits.

The model results in this thesis are in line with the results of these other researches. Table 8.1 shows the storage capacity scenarios in this thesis and the percentage of system demand that these capacities comprise. A storage capacity of 50% covers nearly 1.47% of the system demand, which is thus near the 1.5% maximum required system demand coverage that was found by (Blanco and Faaij, 2018).

Table 8.1: Storage capacity scenarios and the percentage of system demand that these capacities comprise in this thesis.

Storage scenario	Percentage of system demand [%]
25% storage capacity	0.73
50% storage capacity	1.47
75% storage capacity	2.21

The 50% storage might still seem large, as its maximum required capacity is very near the upper limit found in studies with larger RES penetrations than in this thesis. However, this seems plausible according to the remarks about one research in the literature review of Blanco and Faaij (2018). That research discussed by Blanco and Faaij (2018) looks at the power system of Ireland and showed an oddly large storage requirement of 6% of demand at a renewable energy penetration of 80%.

This relatively high requirement is explainable because only wind energy is used in the study due to the location and renewable energy potential of Ireland. Besides, Ireland is not highly interconnected with the rest of Europe. Moreover, the research finds an upper bound of storage capacity as it does avoid curtailment completely, while it could be more cost-effective to allow for some curtailment (Blanco and Faaij, 2018). Storage needs are the highest when generation comes from only one variable renewable energy source as there are no complementary production options available. Additionally, the research considers only the Irish power sector while high wind energy production in winter could be also used for heating demand in winter instead of increasing storage size for the wind energy surpluses in winter.

The limited scope of only Ireland shows similarities to the limited scope of the Netherlands and Germany in this thesis: a large share of wind energy, only the power sector is considered and interconnection capacity to other countries with different energy mixes is limited in this thesis. It is thus explainable that the model results in this thesis show a large upper limit for the required storage capacity in the Dutch system. The difference between this thesis and the study on Ireland is that curtailment is allowed and the generation portfolio is more varied. On the one hand, this explains the large storage requirement found for the Dutch power system in this thesis. On the other hand, it explains why the storage requirement in terms of percentage of system demand in this thesis is not as large as for the Irish system.

8.3. Discussion of scope

The scope in this thesis influences the model results and this involves the geographical scope but also the number of flexibility options and the generation mix included in the model. The large share of solar and especially wind energy has been chosen deliberately for the scope of this thesis in order to show the effects of interconnection and storage capacity in such interconnected power systems.

However, the geographical scope with only the Netherlands and Germany, which have similar weather patterns, influences the system effects of interconnection capacity. A larger scope with more countries included implies more opportunity for interconnection capacity to spatially shift energy between countries with different power systems. For example, including countries such as Portugal and Spain in the scope would make the spatial shift of electricity more beneficial due to the different weather patterns, demand patterns and generation mixes, including RES.

A larger scope represents reality better, assuming that the European national electricity grids are sufficiently interconnected in the future. This would increase the system benefits of large cross-border transmission capacity and in such cases it can substitute and thus decrease the storage needs, as was repeatedly found in literature. Improved system benefits and annual and average dispatch costs can

be reached in reality compared to the model results due to the synergy of storage and interconnection capacity, although this depends on the installed storage capacity as well. The other system benefits potentially improve as well, dependent on the installed storage capacity.

The scope is also limited because only two flexibility options are varied in this study. It is expected that a broader set of flexibility options is required to deal with fluctuations on all levels and timescales in the future power system. The 50% storage needs in the model results in this thesis should thus be seen as an upper bound for several reasons.

One reason is that there are multiple storage technologies, each of them covering different storage requirements in the system and thus offering different system benefits. If there would be more storage options available, the benefits of total available storage capacity could be larger as each of these technologies serves its own application depending on the response time, amount of energy to be stored and the rate at which it is to be transferred. Potentially the same or even larger system benefits, including lower dispatch costs, can be reached with a smaller but more diversified storage capacity portfolio. Seasonal storage is expected to comprise only a small part of the total storage capacity (Blanco and Faaij, 2018).

A more diversified storage portfolio with different storage technologies implies that some technologies for example operate in the distribution grid and in proximity to RES locations or to households like a neighbourhood battery. This will lead to smaller needs for high voltage cross-border transmission as more storage is provided locally, in the national grid. Nevertheless, cross-border transmission capacity is expected to be needed to provide access to storage in another country and to flatten the impact of RES fluctuations (Verzijlbergh et al., 2014). More research is needed to analyse to what extent a more diversified storage portfolio influences the interconnection needs and the system benefits thereof, as this is dependent on the configuration of grid and storage technologies.

Another reason why the 50% storage requirement in this thesis is an upper bound, is that RES oversupply cannot be curtailed in the model runs, while it could be more cost-effective to allow for some curtailment. Curtailment is performed manually and post-processing, which means that it cannot provide for flexibility during a model run. More research is needed to analyse to what extent curtailment influences the interconnection needs and the system benefits thereof. Additionally, Powerflex considers only the power sector while high wind energy production in winter could be also used for heating demand in winter instead. That would imply that a smaller storage size is sufficient for the wind energy surpluses in winter than was found in this thesis. Synergies of coupling the power sector to other sectors are not taken into account, while these synergies could also reduce the transmission and storage needs. A broader scope of the energy system as a whole would give more insight into such synergies.

Another cause for the 50% storage being an upper bound is that demand response is not considered in the model. The demand in Powerflex is inelastic. However, demand response can lower the storage needs as demand response adjusts the power consumption in certain periods to better match supply and demand. This implies that there will be less overproduction hours and less electricity to be shifted in time or space. In the future, demand response is expected to be more present in the system. This can influence the interaction between cross-border transmission capacity and storage capacity operation found in this thesis. Verzijlbergh et al. (2014) researched demand response in terms of controlled EV charging and found that interconnection capacity begins to complement demand response when a large share of RES is present. The cross-border transmission capacity allows for access to storage and demand response in another country and it can flatten the fluctuations of RES.

In this thesis, cross-border transmission capacity has less influence on the fluctuations of RES due to the large share of wind in both the Netherlands and Germany. However, the presence of demand response might increase the need for cross-border transmission capacity in future reality, similar to how storage capacity increases these needs. On the other hand, demand response serves a similar form of arbitrage in time and might therefore decrease the storage needs found in this thesis. Demand response complements interconnection capacity with respect to dispatch costs reduction (Verzijlbergh et al., 2014). The combined effects of interconnection capacity and demand response on the system benefits are thus larger than the sum of their individual effects. Additional research is needed to analyse the synergies of interconnection capacity, storage and demand response and the effects on system

benefits in one power system with a large share of wind energy.

The storage needs and the storage behaviour in the model are also influenced by the assumptions about the hydrogen market. In the model, hydrogen can be sold unrestrictedly by hydrogen demand and the hydrogen price is fixed. In other words, the storage can sell hydrogen restricted solely to its hourly discharging capacity, independent from any hydrogen demand in that hour. If the storage discharges a large amount of hydrogen in the model all at once, then this has no consequences for the hydrogen price. The storage can make large revenues in the model, while this is not true in reality. In reality the hydrogen price will decrease if the storage discharges more hydrogen than the actual hydrogen demand in that hour. The assumption has no influence in case the hydrogen demand is not fulfilled by electrolysis alone, as it is assumed that the remaining hydrogen demand is always supplied by SMR.

The effect of this assumption is that the hydrogen storage could sell more hydrogen than the hydrogen demand and at a higher hydrogen price than in reality. This implies that the storage will discharge more through hydrogen sale than in reality and leads to an overestimation of the storage ability to deal with overproduction hours in the system. Consequently, the system benefits including the reduction in dispatch costs might be overestimated in the model results, especially when storage capacity is 75%. Moreover, in the model results a large storage leads to more import than export through the interconnector and thus the interconnection helps to sell Dutch storage capacity to Germany. In reality, the storage might have less opportunity to deal with the German system as well and there will be less import. Additionally, a storage can make more revenue from hydrogen sale in the model than in reality. The implications of this assumption for storage investments are discussed in more detail in Section 8.5.

8.4. Discussion of modelling technique

The model results are also strongly dependent on the type of model that has been used for this study. This section elaborates on the modelling approach and discusses to what extent the model results would hold in reality, given the discrepancies between the model and the real world as discussed in Chapter ?? about the model and Chapter 4 about the storage function in particular. But firstly, some model artefacts regarding non-converging scenarios and the annual and average dispatch costs will be discussed.

Generally, an important note to make is that Powerflex does not come to a converged solution in scenarios with 25% storage. The average imbalance, absolute imbalance and average electricity price curves do not nearly converge in these scenarios. The convergence curve keeps alternating in these runs, which is caused by the large share of RES and limited flexibility options in these scenarios. This issue has not been resolved in this study. For information on how it has been tried to resolve this convergence issue, the reader is referred to Chapter 6. It should be noted that results from non-converging scenarios cannot be considered valid as the model does not find a solution in these runs.

Moreover, the annual and average dispatch costs results of the model are questionable. It should be noted that Powerflex was found very sensitive to wind energy generation in general, but that in particular the sensitivity of annual and average dispatch costs to wind energy generation showed counter intuitive results. The dispatch costs were found to increase for an increase in wind generation as well as for a decrease in wind generation, which is an unexpected result and has not been resolved in this study. A multivariate sensitivity analysis should potentially be performed to check whether this can explain the outcome. Otherwise the result might be caused by a model artefact. Additionally, during validation of the model it was found that the costs of producers are higher than the revenues. This should imply that none of the producers is willing to supply, however they do supply in the model runs. This is an odd model artefact which might also influence the dispatch costs in the model results.

Regarding the assumptions in the model, Powerflex is an optimisation model using a cost-minimising objective function. This means that costs are minimised from a central decision maker's perspective: the total system costs are minimised while taking into account technical limitations. This implies that actor behaviour is left out of the model: market failures are not taken into account and an efficient market with perfect knowledge and without monopolies and oligopolies is modelled.

In reality, the dispatch is sub-optimal as decision-making happens in a decentralised manner with different actors involved. Individual actors take the decisions without a perfect overview of the system, mainly focused on increasing their revenues and lowering their own cost with for example a risk seeking, risk averse or risk neutral attitude. This does not lead to a set of decisions that together minimise the total system costs, like it is modelled in Powerflex. In reality, the marginal production cost is often different than the electricity price in the spot market. This can have a large effect on the performance of the electricity market and therefore leads to differences between model results and behaviour in the real world.

In addition to that, Powerflex is a deterministic model and operates under perfect foresight. This leaves out uncertainties in the system such as weather circumstances, fuel prices and future demand. This allows the model to optimise the decision variables for the entire year all at once, meaning that an optimal dispatch is reached in the model. In reality, such optimal dispatch cannot be reached as such uncertainties have a large effect on the operation of the power system.

The central decision maker's perspective and the deterministic approach of Powerflex lead to a more optimal dispatch than in reality. The electricity price and hydrogen price are known for every hour of the year and this especially influences the storage operation in the model. A storage is well able to make use of the certainty about prices, renewable generation and demand. In the model, the storage can optimise its charging and discharging decisions over the entire year at once. Storage operation is based on price differences at different moments, which can be difficult to evaluate in reality due to forecast errors in for example renewable generation, thus leading to sub-optimal operation in real life (Van Staveren, 2014). Moreover, interconnection capacity is able to partially cancel out forecast errors over a larger geographical area (Verzijlbergh et al., 2014). An analysis focusing on uncertainties in RES forecasts is recommended to research the robustness of the interaction and system benefits of storage and cross-border transmission capacity findings in this thesis.

Powerflex does not contain an investment module: it optimises the operation of the power system at minimal total system cost and does not give a cost-optimisation of investments. The production portfolio is thus not optimised. Moreover, investments in transmission capacity are very case-specific and require other detailed and complex models, considering for instance the location.

The lack of an investment module leads to large storage and transmission capacity needs as this will give the largest benefits to the system. However, the investment costs of these total capacities can be unacceptably high and such large capacities might thus not be justifiable in reality. The model results in this thesis only show the system effects, but including the capital costs of interconnection and storage capacity can provide for a cost-benefit analysis of these system effects. This might lead to lower storage and interconnection requirements as investment costs are high. The 50% storage need should thus be seen as an upper bound. To still give insight into the cost effects, an analysis of the costs and benefits for different actors is given in 8.5.

Each country in Powerflex is modelled as a single node and assumes a copper plate. This implies that power can flow unrestrictedly and a detailed spatial distribution of renewables and storage is lacking: grid bottlenecks inside each country are neglected. Also required expansion of the distribution network is not taken into account. In reality, the location of storage and interconnector has a large influence on the interaction and benefits in the system. Moreover, increasing interconnector capacity or storage capacity in a certain location might require additional investments in national grids, which might increase costs considerably and which is not taken into account in this thesis. A more detailed transmission grid model including capital costs will be useful to analyse the dynamics of storage and interconnection capacity by zooming in on specific moments in time and geographical locations.

An assumption related to the storage function in the model, is that the storage is modelled according to the dynamic programming algorithm. Dynamic programming implies a piece-wise linear approximation. This means that a limited number of stages and states causes rounding errors in the representation of energy capacity, charging capacity and discharging capacity as not each capacity can be precisely reached given the limited granularity of capacity. In reality these will be a continuous function in which all values within the upper and lower capacity limits can be reached. It is not expected that this influences the conclusions in this thesis. The assumption that the storage can either charge or discharge

in one hour and cannot perform both actions at the same time does influence the storage behaviour. It limits the storage behaviour as it cannot produce hydrogen based on the off-peak electricity price and sell this hydrogen for the peak hydrogen price in the same hour. This assumption is not expected to influence the conclusions in this thesis.

8.5. Practical implications

The aim of this section is to determine the implications of the scenario results for several actor groups in the power sector. The interpretation of the results differs per actor, as per scenario the costs and benefits will differ per actor. The model in this thesis maximises social welfare by minimising the total system costs. But the question is who receives this social welfare; which actor benefits from what in the power sector? The implications for the actor groups of the model results are translated into recommendations for policy makers at the end of this section.

Originally, it was planned to perform a social welfare calculation per scenario. This could show how the costs and the benefits per scenario are divided among the stakeholders. However, during validation of the model it was noticed that producer costs are higher than producer revenue, which is an odd model result. It should imply that producers do not produce while they do produce in Powerflex, meaning that they incur financial losses. For this reason, no social welfare calculations are made.

Another model artefact is that electricity prices become very negative in scenarios with insufficient flexibility options to deal with the overproduction. This model artefact appears most strongly in scenarios with 25% storage. The calculations on costs and benefits for the actor groups are mainly based on electricity prices. All hours with negative electricity prices have been filtered out from the results in order to compare the results between different scenarios. The electricity price in these hours has been set to zero and this results in zero costs or benefits.

8.5.1. Consumers in the Netherlands

An important criterion for consumers is affordability of electricity, thus low electricity costs. The electricity costs for consumers consists of three pillars, namely electricity supply costs, grid costs and taxes. With a larger share of RES in the power system, costs of electricity supply could be expected to go down due to the low marginal production costs of RES. However, more RES in the system also leads to more production fluctuations and the electricity price extremes caused by that can be dampened with storage and interconnection capacity, as researched in this thesis.

Figure 8.1 shows the total electricity supply costs for Dutch consumers in each scenario. Electricity supply costs for consumers are defined as the product of the demand and the price the consumers pay to supply this demand, namely the electricity price. The results show that the consumer costs are lower for a storage capacity of 25% or 50% of the Dutch residual demand than for 75% storage; the difference is approximately €0.3 bn. A smaller storage leads to more hours with negative electricity prices, which have been set to zero costs in this analysis. The large interconnection of 6.25 GW slightly increases the total electricity costs with 0.15 billion euro when storage is small.

A large storage capacity of 75% leads thus to an increase in consumer costs of approximately €0.3 bn. A larger storage capacity leads to fewer electricity price extremes in the Netherlands. Especially the negative prices are reduced when a larger storage capacity is present and thus there are fewer hours with zero costs. The price duration curves in Chapter 7 show that a larger interconnection capacity only has a small effect on the electricity prices. However, more interconnection capacity when storage is large can decrease the consumer costs slightly, with approximately €0.03 bn.

The consequences for Dutch consumers thus depend on both storage size and interconnection capacity. A small storage is beneficial for consumers, whereas combining this with a large interconnection capacity slightly increases the costs. A storage capacity of 75% of the residual demand is not beneficial from a consumer's point of view, although combining a large storage with a large interconnection capacity can slightly reduce the burden as the interconnector can decrease the costs.

A storage capacity of 75% of residual demand is thus generally not desirable in terms of total consumer costs whereas the desirability of increased interconnection capacity depends on the storage

capacity development in the Netherlands. If storage capacity is small, a small interconnection capacity is desirable for consumers. If storage capacity is large, a large interconnection capacity is desirable. The upper bound of 50% storage is as beneficial as a storage capacity of 25% in terms of consumer costs. Generally, investments in cross-border transmission capacity do not lead to large benefits for consumers.

However, only looking at electricity supply costs thus does not give a complete picture as electricity costs for consumers consist of grid costs and taxes as well. Part of the taxes is used by the government for renewable energy projects or to discourage electricity usage by consumers, which is subject to government policy and currently often under debate (Stellingma, 2019). The grid costs can rise as investments in cross-border transmission capacity but also in national distribution and transmission grids will be needed towards 2030, in order to deal with an increased share of RES and required storage capacity. A cost-benefit analysis with location-specific data about storage and grid, including the capital costs of grid investments is required to have a complete overview of the effects of the scenarios in this thesis on the grid costs for consumers.

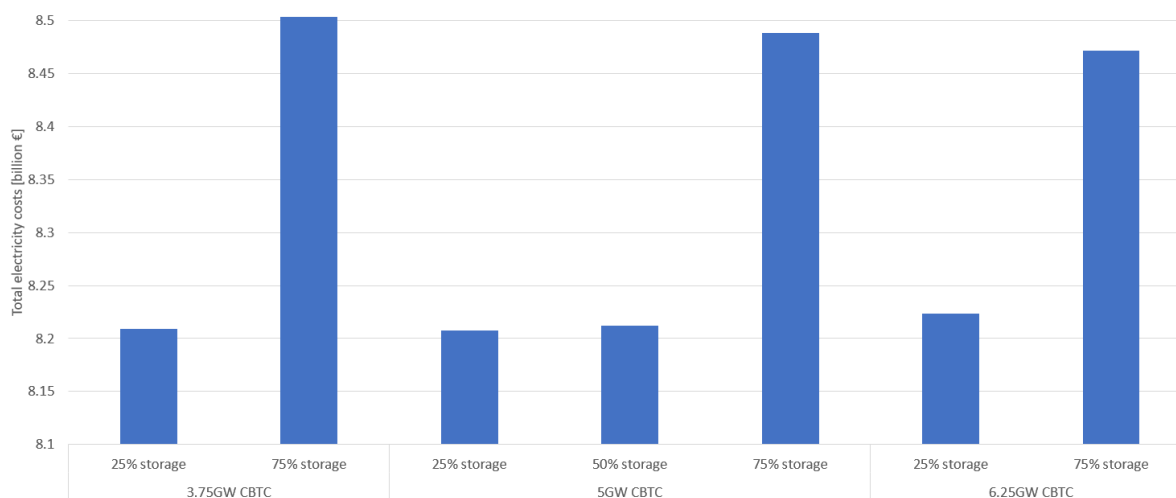


Figure 8.1: Total electricity supply costs for consumers for all scenarios

8.5.2. Producers in the Netherlands

Figure 8.2 shows the total revenues of solar power producers, wind power producers and conventional power producers. Note that it would have been more logical to look at the profits of the producers instead of the revenues. Conventional power producers have start-up, shut-down and fuel costs which need to be taken into account. However, during validation of the model it was noticed that producer costs are higher than producer revenue, which is an odd model result. It should imply that producers do not produce while they do produce in Powerflex, even though it leads to financial losses. Therefore, it was chosen to look at revenues of all producers instead of profits. The revenues are defined as the product of production and the price that is paid for the supply, namely the electricity price. All negative electricity prices have been set to zero revenue in this analysis. The results show a large difference in revenue between the producers.

Solar power producers have a relatively small gain in general, which is €0.2 bn when storage capacity is 75% instead of 25% of negative residual demand. On the other hand, wind power producers can benefit much more in general and specifically from the presence of a larger storage. A 75% storage capacity gives wind power producers a revenue of € 0.5 bn more than when storage capacity is 25%. This is probably due to the larger installed wind power capacity and more hours with larger production output than solar power production. The cross-border transmission capacity does not have much influence on the revenues of RES producers; revenues are almost equal.

Another important criterion for RES producers is curtailment, which reduces the operating hours of RES. The results in Chapter 7 show that a reduction of 1000 curtailment hours occurs in scenarios

with 75% storage compared to scenarios with 25% storage. Between 50% and 75% storage a reducing marginal benefit occurs as the reduction in curtailment is only 200 hours. This reducing marginal benefit does not appear in the revenues of RES producers, probably because a larger storage removes the price extremes and thus lowers the revenues.

Contrarily, cross-border transmission capacity does have an influence on the revenues of conventional power producers if there is very small flexible capacity available in total in the system. Their revenue is very low (€ 0.1 bn) in the scenario with the least flexible capacity; 25% storage capacity and 3.75 GW interconnection capacity. In this case there is much overproduction by renewables in the Netherlands and many hours with negative electricity prices. The conventional producers also cannot serve the German demand in this situation as interconnection capacity is small.

A storage capacity of 50% and 75% reduces the revenue of conventional power producers considerably. Available renewable production can be better utilised due to the larger storage capacity; RES overproduction is stored and later used in hours of high electricity demand. This reduces the production and production hours of conventional producers, leaving them less revenue. Storage reduces the negative but also positive electricity price extremes and conventional producers will thus receive a lower electricity price for their supplied power.

The consequence of more storage or more interconnection for power producers thus depends on the type of power they supply. For revenues of conventional power producers, a small storage of 25% is beneficial, although the interconnection capacity should be large enough to allow for electricity trading with Germany as well. For conventional power producers it is important to realise that their revenues decrease when storage capacity is large. More storage capacity can thus have negative consequences for power plant profitability and might eventually lead to closing these plants.

Cross-border transmission capacity does not affect the revenues of wind and solar power producers much. Renewable power producers benefit when storage capacity is large; wind power producers benefit to a larger extent than solar power producers. This benefit can be expressed in curtailment hours and revenues that come with that. Increased storage capacity can thus be a way to improve profitability of renewable energy projects.

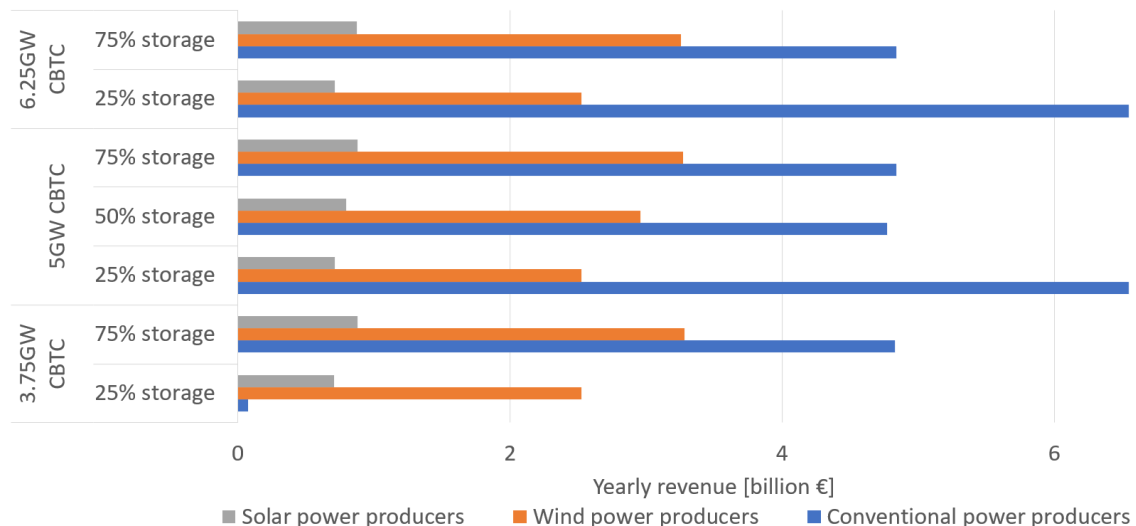


Figure 8.2: Total revenues for solar, wind and conventional power producers for all scenarios

8.5.3. Storage operators in the Netherlands

Figure 8.3 shows the charging costs, the total income and revenues from selling hydrogen and electricity for all scenarios. Total charging costs are defined as the product of charging capacity and the electricity price in hours of charging. The revenues from hydrogen or electricity refer to the total amount of money that is received from either discharging through hydrogen sale at the hydrogen price in that

hour or discharging through electricity sale at the electricity price in that hour. Net income is the money that is effectively earned after adjusting the total revenue for the charging costs. All values are shown per kW installed storage capacity in the particular scenario, so that the results are comparable.

The results show that a small storage of 25% can generate more revenue per kW installed capacity from electricity sale as compared to a large storage. Storage capacity diminishes price extremes, thus leading to fewer high electricity prices when storage is larger. On the other hand, large storage generates more revenue per kW installed capacity from hydrogen sale. Charging costs are lower for a small storage, which might be caused by removing the electricity prices below zero. Generally, a large revenue stream is generated by hydrogen sale in all scenarios. This effect is more pronounced for a larger storage.

Total income per kW installed capacity is the lowest in scenarios with 25% storage. Moreover, total income is largest in the scenario with 50% storage capacity. Even though the difference is small, this indicates a point at which not much more can be gained with increasing storage capacity. For storage operators this implies that the profitability of investments in storage capacity are thus dependent on the total available storage capacity already in the system. The profitability of investments seems less dependent on the interconnection capacity. An effect is only noticeable in the 75% storage scenarios; a larger interconnection capacity increases the revenues from hydrogen sale but charging costs are also higher so it only slightly influences the total income.

The net income per kW installed storage capacity should be compared to the investment costs per kW to examine the profitability of the storage. The literature review in Chapter 2 states that the investment costs for Power to Gas with hydrogen production will even out around 500 €/kW in 2030, based on current investment costs of 1000-3000 €/kW for Power to Gas with hydrogen production and a realistic decreasing trend of 13 % per doubling of the installed Power to Gas capacity (Thema et al., 2016).

Comparing net income per kW to investment costs per kW shows that the storage would be very profitable. However, this result should be handled with caution as the hydrogen storage in the model can sell more hydrogen than the hydrogen demand and at a fixed hydrogen price. The storage can sell its hydrogen unrestrictedly and the hydrogen price does not respond to the hydrogen supply in the market. Therefore, revenues from hydrogen sale are expected to be lower in reality. This implies that the storage will be less profitable in reality than is found in this study. Moreover, forecast errors regarding RES supply are not considered. Further research is needed for more information on the business case of hydrogen storage.

Even though the hydrogen market is not modelled in sufficient detail for a business case analysis, some useful remarks can be made for storage operators regarding hydrogen production from wind energy (green hydrogen). The demand for green and import hydrogen is estimated at 23.52 TWh in the year 2030, which is a conservative estimate (Hers et al., 2018). A large share of this hydrogen demand is supplied by the storage in all scenarios in this thesis, despite the storage size and interconnection capacity, as can be seen in Chapter 7. A 25% storage capacity supplies 14 TWh, a 50% storage capacity supplies 15 TWh and a 75% storage supplies 18 TWh of hydrogen. Hydrogen production with electrolysis in a system with a large share of wind energy is thus found feasible, which was one of the potential barriers identified by Hers et al. (2018). Another potential barrier is formed by the investment costs.

8.5.4. Transmission system operator

Two aims of the transmission system operator (TSO) TenneT are to provide for market integration and market efficiency. Congestion rents indicate the level of market integration: low congestion rents are an indication of improved price convergence between countries and low dispatch costs. Figure 8.4 shows the total congestion rents for each scenario. Congestion rents are defined as the product of the cross-border power transfer and the price difference between both countries. A larger interconnection capacity should eventually lead to smaller price differences, ultimately converging to zero. Congestion rents are an income for the TSO, but not a profit. They are expected to invest their income from congestion rents into an improved transmission grid. Profits that are left will be returned to the consumer.

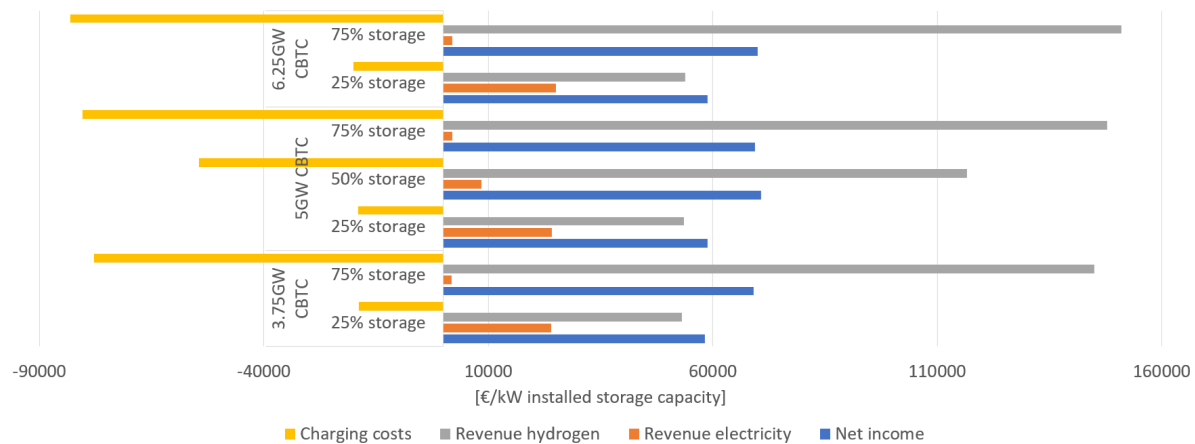


Figure 8.3: Charging costs, total income and revenues from selling hydrogen and electricity for all scenarios. All values are shown per kW installed storage capacity in the particular scenario, in order to compare the results.

The TSO aims at low congestion rents.

Congestion rents are reduced more in scenarios with 75% storage than in scenarios with 25% storage. However, the effect of larger interconnection capacity in scenarios with 25% and 75% storage is the opposite from what can be expected. The power transfer is increasing but the prices between the countries do not converge sufficiently enough to obtain a congestion rent reduction. The congestion rents even increase with increasing interconnection capacity in all scenarios. This can indicate that the cross-border transmission capacity is not large enough for the electricity prices to converge sufficiently. In other words, the markets would not be sufficiently integrated yet.

However, it should be noted that the model used in this study shows convergence issues, leading to extremely negative electricity prices in many hours, especially in scenarios with 25% storage. Moreover, the dispatch costs results in this thesis are questionable due to model artefacts. Both lead to a decreased trustworthiness of these congestion rents results.

Nevertheless, some conclusions for TenneT can be made from the results in this thesis. The system benefits of increased interconnection capacity reduce if this interconnection exists between only two countries with a similar RES potential and similar weather patterns, like in the scope of this thesis. Interconnection capacity has less influence on the fluctuations of RES in such system. The system benefits of interconnection capacity are expected to increase when there is more interconnection with countries with different weather patterns and RES potential like Spain for example. The results in this thesis thus show the importance of a highly interconnected European grid. TenneT's current interconnections, like BritNed, NorNed and the COBRACable, are thus important for the integration of RES in the system. TenneT can also stimulate an interconnected grid through active participation in ENTSO-E.

Moreover, it is important to realise that in such system with similar RES and weather patterns, seasonal storage and cross-border transmission capacity are found complementary to a certain extent in this thesis. Storage capacity complements (increases the need for) interconnection capacity, while interconnection capacity does not influence the need for storage capacity. The increased need for interconnection capacity is due to more import from Germany, which means that interconnection helps to sell Dutch storage capacity in Germany. TenneT can thus decrease the need for interconnection capacity by promoting the development of storage in Germany. TenneT's role as only cross-border TSO in Europe, with grids in the Netherlands and Germany, is particularly suitable for this. Additionally, more local electricity storage and diverse flexibility options can lower the needed grid investments as well. The results in this thesis are in line with conclusions in the Infrastructure Outlook 2050, published by GasUnie and TenneT (GasUnie and TenneT, 2018).

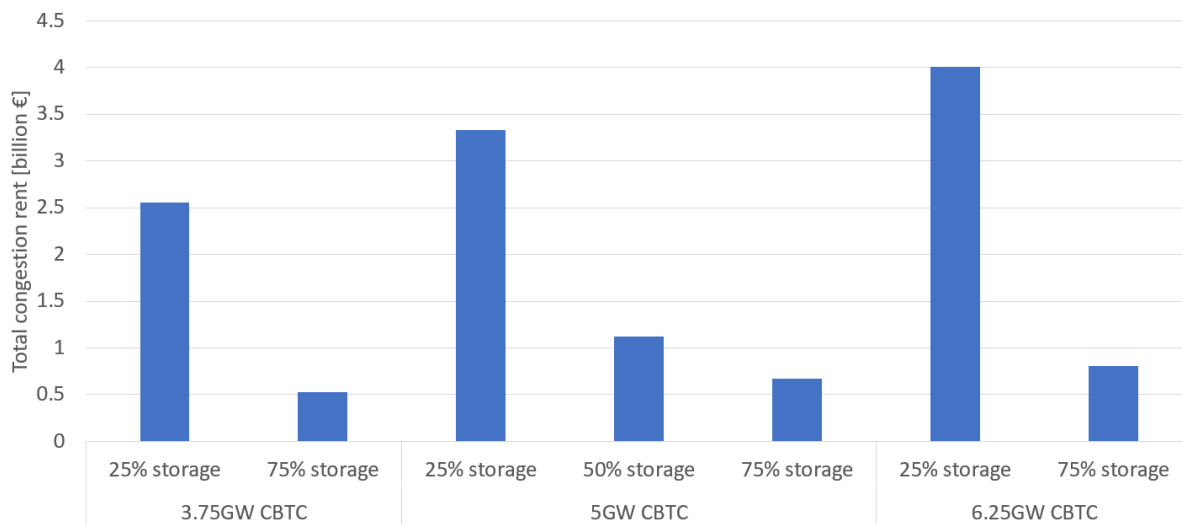


Figure 8.4: Congestion rents for all scenarios

8.5.5. Policy recommendations

The three goals of Dutch energy policy are affordability, sustainability and reliability. This thesis does not analyse specific variables on the reliability of the system as the model algorithm ensures that demand is supplied in all hours of the year. Hours with loss of load can thus not exist in the presented scenario results. Currently, there is much debate about the required policies to reach the climate agreement (Rijksoverheid, 2019). Among others, increased renewable energy generation and potentially CCS are needed to reach the emission reduction that the Dutch government aims at. This section discusses the implications of the results in this thesis for policy makers.

This thesis shows that hydrogen production through electrolysis might play an important role in the future power system. It can reduce the price extremes in the Dutch electricity market and lowers curtailment needs, which improves the affordability of electricity supply. The estimated hydrogen demand for 2030 could be met in all scenarios, thereby reducing the fluctuations in supply caused by RES. Moreover, the availability of storage can improve the profitability of renewable energy projects as storage availability reduces curtailment needs. Storage can thus help to increase the share of RES and to reduce its production fluctuations in the system, which is expected to lead to CO₂ emissions reductions.

Hydrogen production with electrolysis in a system with a large share of wind energy is found feasible in this thesis as a large share of estimated hydrogen demand for 2030 can be met in all scenarios. Currently, hydrogen storage capacity based on electrolysis is not developing rapidly due to its high capital costs; which forms a barrier for its development (Hers et al., 2018). Additional policies are needed to support the development of hydrogen production from electrolysis, such as subsidies or regulations. This can lead to a capital cost reduction due to more research and development and inclining investments in electrolysis. CCS obligations can also support the development of electrolysis, as it increases the costs of hydrogen production from SMR and thereby strengthens the competitiveness of electrolysis in the hydrogen market.

More research is needed regarding the size of the required hydrogen storage as this study considers only two flexibility options. Nevertheless, storage capacity should not be larger than the upper bound of 50% storage capacity found in this thesis. A larger storage capacity lowers the revenues of conventional power producers with approximately € 2 bn. This influences profitability of conventional plants and could lead to closure, which is undesirable as conventional plants are expected to be needed as back-up plants in hours of underproduction. In such cases, policy makers need to take additional measures such as a capacity remuneration mechanism to account for the income of conventional producers in order to secure back-up needs. A storage larger than 50% also increases consumer costs.

System effects of increased cross-border transmission are generally small in this thesis, because

it interconnects only the Netherlands and Germany. Moreover, the large share of wind power in both countries reduces the benefits. The results thus show the importance of an interconnected European electricity grid for the integration of RES, due to the different weather patterns, demand patterns and RES potentials. In such system, the benefits of interconnection capacity are expected to be larger. Moreover, it is important to realise that storage capacity increases cross-border transmission capacity deployment, whereas interconnection capacity does not influence storage capacity deployment in a system with a large share of RES and similar weather patterns. Large storage increases electricity import from Germany to the Netherlands, which means that interconnection capacity is used to sell Dutch storage in Germany. A smaller interconnection capacity can be sufficient to serve both market if storage would be developed more locally.

8.6. Conclusions

This chapter discussed the model results more extensively, compared them to existing literature and explained to what extent the scope and modelling approach influence the model results and whether they can be compared to affects that can appear in reality. Limitations in scope and modelling approach were identified and the practical implications of the model results were interpreted for different actors in the power sector.

The dispatch costs results are not considered valid due to an identified model artefact. Moreover, scenarios with 25% storage do not come to a converged solution due to limited flexibility options in the system to deal with a large share of RES. Nevertheless, some conclusions can be drawn from the model results.

The model results show that the positive effects of enlarging interconnection capacity are small. This is partly caused by the deliberately chosen large share of wind in the system and partly caused by the scope including only the Netherlands and Germany, while the Dutch grid is more interconnected in reality. Nevertheless, it can be concluded that cross-border transmission capacity leads to small system benefits if it is used to interconnect areas with similar RES potential, weather patterns and demand patterns.

In the model results, storage capacity increases the need for cross-border transmission capacity in the model results. However, cross-border transmission capacity does not decrease the need for storage capacity, as an enlarged interconnection capacity hardly has any effect on storage deployment. Storage capacity thus complements (increases the need for) interconnection capacity, while interconnection capacity does not influence the need for storage capacity. This interaction can be influenced if a more diverse set of flexibility options is modelled, such as curtailment, demand response and different storage technologies. Moreover, an influence of interconnection on storage utilisation can be expected in reality because the system benefits of interconnection capacity are larger in reality.

Storage capacity leads to fewer price extremes and a reduction of curtailment needs. In the model results, storage capacities larger than 50% storage are not justifiable as they lead to declining marginal benefits. The results may show inclining and declining benefits summed up into overall inclining benefits, leading to a distorted picture. Nevertheless, from the model results it can be concluded that a storage capacity of 50% can be considered an upper bound. The storage operation is influenced by the assumptions regarding the hydrogen market and the deterministic approach in the model. Moreover, a more diversified storage portfolio and more flexibility options is expected to lead to smaller storage requirements.

Practical implications for several actors in the power sector lead to recommendations for policy makers. The development of hydrogen storage should be supported because this allows for the integration of RES in the Dutch system. This should be combined with the development of a European interconnected grid and local electricity storage. The latter can reduce the interconnection capacity investments. Moreover, back-up capacity should be secured as profitability of conventional producers goes down when storage is introduced.

Conclusion and Recommendations

The Dutch government aims at 70% of electricity production from renewable energy sources in 2030 in order to reach a CO₂ emission reduction of 49% as compared to 1990 levels (Rijksoverheid, 2019). An increasing share of renewable energy generation in the electricity grid requires more flexibility of the power system in order to deal with the fluctuations in supply that are inherent to renewables, because of their weather dependency. Currently, wind power is developing rapidly on the North Sea and it could possibly reach a level of 50 GW by 2050. Such a large share of wind energy can lead to seasonal fluctuations in generation and hydrogen storage was identified as a storage technology that can deal with that. Moreover, hydrogen storage can earn extra revenues by hydrogen sale as well, which can be valuable given the expected development of the hydrogen market by 2030.

Another option to deal with the large scale fluctuations is cross-border transmission capacity. The aim of this research was to analyse the system effects of seasonal hydrogen storage and cross-border transmission capacity in a future Dutch system with a large share of wind. What are their effects on the dispatch costs and to what extent do they complement each other in deployment. A cost-minimising electricity market model was used to analyse these effects and to gain insight into the complementarity of deployment, for varying hydrogen storage capacity in the Netherlands and varying interconnection capacity between the Netherlands and Germany. In this chapter, answers to the research questions are given, followed by an identification of the limitations and uncertainties in this research. The chapter concludes with a set of recommendations for policy makers, model improvements and future research.

9.1. Sub-questions

- **How do seasonal storage and interconnector deployment complement each other in serving flexibility?**

The interconnector deployment is influenced by the size of the storage capacity in the model results. A small storage, which covers 25% of negative residual demand in the Netherlands, leads to more export than import. In case of a small storage, there are still hours of overproduction and interconnection capacity helps to export this overproduction to Germany. Interconnection capacity is used at full capacity during more hours when storage is large, which is a storage capacity as large as 50% or 75% of the negative residual demand in the Netherlands. A large storage leads to more import than export through the interconnector, as seen from the Dutch power system perspective. When storage is large there are fewer hours of overproduction and the interconnection capacity allows for the use of Dutch storage capacity to Germany. There are more hours of import so the German overproduction is stored in the Dutch storage. This indicates that interconnection capacity helps to sell Dutch storage capacity in Germany in the model results.

Storage capacity thus increases the need for cross-border transmission capacity in the model results. However, cross-border transmission capacity does not decrease the need for storage capacity, as an enlarged interconnection capacity hardly has any effect on storage deployment. Storage capacity thus complements (increases the need for) interconnection capacity, while interconnection capacity

does not influence the need for storage capacity. However, the increase in storage capacity between 25% and 50% storage has larger effects on interconnector deployment than the increase in storage capacity between 50% and 75% storage. This indicates that marginal influence on interconnector deployment reduces if storage capacity is increased.

- **To what extent do seasonal storage capacity and interconnector capacity influence the dispatch costs?**

The effects of increased interconnection capacity on annual and average dispatch costs are small in the model results. Both annual and average dispatch costs in the Netherlands increase slightly when interconnection capacity is enlarged in the model. This increase is larger in scenarios with 75% storage than in scenarios with 25% storage, but the effect is nevertheless small.

The model results show that average dispatch costs decrease between 25% storage and 50% storage in all scenarios, despite the interconnection capacity in that scenario. Storage capacity of 75% increases the average dispatch costs slightly. The annual dispatch costs decrease when storage capacity is enlarged.

9.2. Main research question

- **What are the system effects of cross-border transmission capacity and seasonal storage on the future Dutch power system with a large share of wind energy?**

Only small benefits of increased cross-border transmission capacity were found in this thesis. Minor system effects were found for enlarged interconnection capacity; it has only a small effect on price extremes and curtailment needs. The model results show that an increased interconnection capacity has more positive effects on the performance indicators in scenarios with 25% storage capacity than in scenarios with larger capacities, but the positive effects are nevertheless small. It can be concluded from this research that a similar RES generation mix among interconnected neighbouring countries reduces the benefits of cross-border transmission capacity.

Regarding the effects of storage capacity, the first increase in storage capacity brings the largest system benefits and marginal benefits reduce if storage capacity is increased in the model results. Saturation in the effects on system benefits is visible between 50% and 75% storage capacity, despite the interconnection capacity in these scenarios. Price extremes and curtailment are reduced, but to a lesser extent than between 25% and 50% storage. Storage capacities larger than 50% storage are not justifiable as they lead to declining marginal benefits. In conclusion, 50% storage capacity can be considered an upper bound of required storage capacity in the model results.

9.3. Limitations

The results should be seen in the light of the limitations of this study. Partly, these limitations are caused by the scope of the study: the geographical scope with the Netherlands and Germany is limited as well as the analysis for only two flexibility options. A 50% storage can be identified as an upper bound of storage requirements and more research is needed to analyse storage requirements in the Dutch system, as the results may show a distorted picture due to the limited number of flexibility options in the modelled system. Moreover, the presence of demand response in the system might influence the complementarity of deployment found in this thesis.

From this thesis it can also be concluded that enlarging interconnection capacity leads to small system benefits when interconnection capacity is limited and connects countries with similar RES potential and weather patterns. A larger scope, including interconnection with multiple neighbouring countries or the entire European Union is expected to lead to larger benefits of increasing interconnection capacity than found in this study. This would match reality better, as the current European grid is already interconnected to a certain extent. Moreover, the hydrogen market in the model is assumed to have an unlimited hydrogen demand with a fixed hydrogen price, causing the operation and revenues to be more promising than in reality.

Also some limitations of the model were identified. The model does not find a converged solution for scenarios with limited flexible capacity in the system, which implies that such runs cannot be considered valid. Moreover, the annual and average dispatch costs results are questionable due to identified model artefacts and this needs further research. Additionally, it should be noted that the model used in this thesis takes a deterministic approach and does not contain an investment module. This implies that uncertainties regarding forecast errors of renewable supply are left out and no complete cost-benefit analysis of storage and grid investments can be made.

9.4. Recommendations

The conclusions and limitations of this thesis can be translated into a set of policy recommendations, modelling recommendations and recommendations for future research. These will be discussed in this section.

9.4.1. Policy recommendations

The system benefits of interconnection capacity and seasonal storage capacity have been identified as measures to increase the share of renewables in the system, thereby contributing to the emission reduction that the Dutch government aims at. Hydrogen production with electrolysis in a system with a large share of wind energy is found feasible as a large share of the estimated hydrogen demand for 2030 can be met in all scenarios. Besides the recommendations for further research which are also relevant for policy makers to gain more insight, the following recommendations for policy makers have been formulated from the results of this thesis:

- *Support the development of hydrogen storage based on electrolysis*
Promoting hydrogen storage capacity based on electrolysis by for instance regulations and subsidies can lead to more research and development and increasing investments. This can decrease the capital costs of electrolysis, which is currently a barrier for its development. CCS obligations can also support the development of electrolysis, as it increases the costs of hydrogen production from SMR and thereby strengthens the competitiveness of electrolysis in the hydrogen market.
- *Promote the development of a European interconnected electricity grid*
An interconnected European electricity grid is important for the integration of RES, due to the different weather patterns, demand patterns and RES potentials among different countries in Europe. In such system, the benefits of interconnection capacity are expected to be larger.
- *Promote local electricity storage deployment within the Europe Union*
A smaller interconnection capacity and smaller total storage capacity can be sufficient to serve both market if storage would be deployed locally. Storage capacity increases cross-border transmission capacity deployment, whereas interconnection capacity does not influence storage capacity deployment in a system with a large share of RES and similar weather patterns. Large storage increases electricity import from Germany to the Netherlands, which means that interconnection capacity is used to sell Dutch storage in Germany. This would be less needed if Germany installed more storage capacity locally.
- *Secure back-up capacity by remunerating conventional power plants when it becomes required*
Back-up generation capacity is supplied by conventional power plants and will be needed for security of supply during periods of underproduction. The availability of storage capacity in the system reduces the profitability of conventional power plants, which might lead to closure of these plants. Additional measures such as a capacity remuneration mechanism can become required to secure the income of conventional producers.

9.4.2. Model recommendations

Powerflex has been validated before with historical data from the years 2013 and 2014 of the Dutch APX day-ahead market and could well-reproduce the market behaviour (Hers et al., 2016). However, in this thesis it was found that Powerflex shows some deficiencies if it has to be run for scenarios with a large share of RES and insufficient flexibility measures to deal with the overproduction hours. With the increasing share of renewable energy sources in the power system, it is recommended to make some

model adjustments to allow for studies of future situations of the power sector. Moreover, issues with dispatch costs results were identified. Therefore, the following recommendations are formulated.

- *Include multiple flexibility options in the model*

Including more flexibility options in the model might solve the convergence issues in scenarios with a large share of RES as it gives more options to deal with overproduction hours. Suggestions for other flexibility options are for example to diversify the technologies in the storage portfolio, to include demand response or to make curtailment possible during a model run by including a price floor, instead of performing curtailment manually and post-processing.

- *Evaluate the dispatch costs calculations*

The first step can be to analyse why the production costs of conventional producers are larger than their revenues, given their output levels and the electricity price in each hour. Also the sensitivity of the model to wind generation can be evaluated. This thesis performed a one-at-a-time sensitivity analysis but a multivariate sensitivity analysis might be needed for more insight.

- *Add more detail to the storage function*

More detail in the storage function will allow for more realistic behaviour of the storage in the model. An example of more detail is to allow for charging and discharging in the same hour in the function. Also the hydrogen market can be modelled more realistically by modelling price responsive demand or by adding a cap to the hydrogen demand. It should be researched whether this cap should be modelled per hour, per week or per year.

9.4.3. Recommendations for future research

Apart from the recommendations to improve Powerflex related to the model limitations, some directions for future research can be identified. These directions are based on the limitations regarding scope and type of model that is used. The following recommendations for future research have been formulated:

- *Analyse the system focusing on the limited predictability of RES*

An analysis focusing on the uncertainties in RES forecasts is recommended as this would give insight into the robustness of the interaction and system benefits of storage and interconnection capacity results found in this thesis. Uncertainty in wind predictions may lead to a sub-optimal dispatch which might influence the system benefits that either storage capacity or interconnection capacity can bring for the system. The first step in analysing the robustness of the results can be to run Powerflex with demand and RES generation time series of different years.

- *Research a larger set of flexibility options*

Researching a larger set of flexibility options, including multiple storage technologies, curtailment and demand response, would give more insight into the 50% storage capacity upper bound and interconnection system benefits and interactions found in this thesis as this is expected to be influenced by other flexibility options as well. Additionally, a broader scope of the energy system as a whole would show synergies resulting from coupling the power sector to other sectors.

- *Analyse the 50% storage capacity upper bound*

Scenarios can for example be run for a range of storage capacities between 25% and 50% storage to see where the decreasing marginal benefit starts. The upper bound can be analysed by a broader set of flexibility options as mentioned in the previous recommendation, but also by modelling the hydrogen market more realistically with a limited hydrogen demand or price responsive behaviour.

- *Perform case-specific cost benefit analyses*

Case-specific analyses of the costs and benefits of investments in storage and interconnection capacity can show how this influences the capacity requirements as large capacities might not be justifiable due to high capital costs. An investment module could be connected to an operational model to get a more complete picture.

10

Reflection

The aim of this chapter is to reflect on this research and it is therefore written in a more personal manner. I feel like I could already write a thesis only about the process of writing this thesis, but I decided to make a selection of topics to discuss.

The initial idea of this project was to look at the 2050 power system with ENTSO-E scenarios and the United Kingdom included. Besides including a storage function through dynamic programming, I would have to use new datasets in the model which were not yet available. Before continuing with this project idea, I made sure to have a look at the Matlab code of Powerflex and to have a first understanding of dynamic programming. However, it turned out to be difficult to oversee the issues that would arise during programming and the time it would take to include other data in Powerflex.

Even though I might have read enough literature in the end, I think that I read papers and wrote my literature review at the wrong moment. I planned to do this differently as before having my kick-off at the beginning of summer, I realised and indicated that my research proposal did not contain a clear plan yet. However, it was still advised to kick-off the project and so my plan was to take some time at the beginning of the project to more clearly define the knowledge gap of my research and corresponding project plan.

This worked out differently due to the expected leave of a junior researcher at CE Delft who could explain me how to include UK data in the model, among other things. I got a list of tasks and I realised that these tasks were not the most needed at that particular moment of starting with the project, especially because it was still not completely clear to me what I was going to do. Part of the tasks could even be categorised as 'nice-to-haves'. Eventually, I spent the summer months on tasks that I did not use in the end and my literature review was performed and written way later in the project.

Research is an iterative process as it is often not possible to oversee the implications of a chosen path, which should be accepted as part of the nature of research. However, the described example is a situation in which I realised from the beginning that the path I was taking was sub-optimal. To believe in your own ideas and to follow them takes a healthy amount of courage and stubbornness, which I had to gain more throughout the course of the project. I believe this could be helpful in my professional life hereafter.

Writing this thesis was a steep learning curve whereby I learned more about dynamic programming. But I also realised now and then that the paths taken are not always optimal which as such again is a learning process. Not every knowledge gained was as useful for this thesis but made me realise that I had to follow a different approach on certain occasions, to choose other directions. I learned to be more practical in approaching certain points of interest in this prospect.

At the beginning of the project I started a digital logbook in which I wrote down my notes and understandings from meetings about the project. This turned out to be a great source of information throughout the course of the project as it was easy to retrieve information from discussions earlier on. This is something I would do again when starting such a large project and I would complement this with

a logbook with short notes on the progress and decisions taken. The latter is something I did not do during this thesis project, but which would have been very useful in hindsight.

During the thesis project I also realised how valuable it is to work on a project with team members. During my studies I experienced that meetings with team members can take a considerable amount of time and do not always result in workable conclusions. However, during my thesis project I noticed how difficult it can be to structure your ideas without discussing them with someone who knows the details of the project you are working on.

I also experienced the importance of a well-documented model. Powerflex is a complex and un-transparent model, especially to someone who is not a very experienced electricity market modeller yet. The model is available in two ways: an online user-friendly platform and the offline source code in Matlab. Firstly, I learned to work with the online platform of which there was a manual available. However, I had to use the source code in order to add the storage function to Powerflex and to perform the actual research. The source code of Powerflex turned out to work differently than the online platform at certain points and it was often difficult and time-consuming to find out how it was different. Quite some emails have been sent to the company who wrote the source code of the model, not always leading to a satisfying result. Some of the difficulties were so time-consuming that it was decided to accept these as model limitations and describe that in this thesis. Examples of these are the convergence issues and the CO₂ emissions that could not be defined as a model output.

At the start of the project, I did not have any experience with dynamic programming and it took considerable time to understand how the storage function could be implemented. The first version of the function took about an hour to run in itself. This slowed down the run-time of Powerflex considerably, as originally the model was able to complete a run within 10 minutes. With the storage function included, a run of 20 iterations and total storage capacity divided among several sub-storages with different efficiencies was now taking over 24 hours to finish.

In order to increase the speed of the function within the model several things have been tried. I tried to skip iterations of the model; so to only run the storage function every fifth loop or every second loop. This did not work as it caused too large fluctuations in the model; the model had problems to converge. Changes in the optimal path of the storage function caused too large changes in the entire model. I also searched for other ways to increase the speed of the function. A possibility is successive approximation, but soon after reading a bit more about this I realised that this would imply a new structure for my code.

Because of time constraints, I decided to rewrite the solution structure I already had instead of starting with a new structure. In the first version of the code, all state combinations were calculated for each stage, which led to a large number of calculations. A considerable part of these calculations was not needed, as these combinations could never be reached within an hour with the given charging or discharging capacity. By only evaluating the combinations that lie within the range of charging and discharging capacity, complemented with some additional insights on how Matlab works with matrix calculations, the run-time of the storage function was decreased to 0.26 seconds. This was considered an acceptable result for this research. Chapter 5 explains in more detail how the combinations of stages and states are evaluated in the function.

The storage incurs losses in terms of energy as well as money. Unfortunately, energy losses due to the conversion and reconversion steps in the charging and discharging process cannot be deduced from the model results. The original requirements for the storage function were to model its effects in the market and thus to capture its price responsive behaviour. Therefore, the storage conversion and reconversion efficiencies influence the price paid and received by the storage. Conversion costs more than the electricity price as more electricity is bought than stored and reconversion happens at a lower price than the electricity price as less electricity is sold than was stored. In hindsight, more insight could have been gained from the model results if energy losses were modelled as well.

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