Power To Paris

The Role of Carbon Capture and Storage in a Future European Electricity System that Abides by the COP21 Climate Agreement

Freek Zuiderveen Borgesius

ECOFYS

TU Delft Delft University of Technology

December 29, 2017

POWER TO PARIS

The Role of Carbon Capture and Storage in a Future European Electricity System that Abides by the COP21 Climate Agreement

by

F.W. Zuiderveen Borgesius

In partial fulfilment of the requirements for the degree of

Master of Science

Industrial Ecology

First Supervisor (Delft Technical University)	:	Remco Verzijlbergh
Second Supervisor (Leiden University)	:	René Kleijn
Company	:	Ecofys B.V.
Supervisor Ecofys B.V.	:	Lou Ramaekers
Student number Leiden	:	1753231
Student number Delft	:	4525310

Summary

The Paris climate agreement set out to limit global warming to 2 °C in 2100. To reach this goal with a probability of 50%, the European power sector needs to reduce its CO2 emissions with 96% in 2050, compared to 2014 levels (IEA, 2016a). Renewable energy sources could provide a solution to this challenge, but their generation profile is subjected to variability, unpredictability and is location-specific. Grid flexibility is then required to maintain security of supply. This can be achieved in several ways. By upgrading the transmission grid, power supply can be distributed over different and larger areas. Electrical energy storage can account for supply and demand mismatches. Carbon capture and storage (CCS) could potentially decrease the required renewable energy capacity, while simultaneously increasing grid flexibility by enabling fossil fuel power plants to serve as backup capacity.

This research focuses on finding a cost-optimal composition of technologies, while abiding by the goals set in the Paris climate treaty. To investigate this objective, two optimisation models are deployed: the linear programmed model I-E-Energy and the unit commitment model Powerfys. Comparing these models in search for a cost-optimal power system, this research focuses on the following research question: *What is the effect of the goals set in the Paris agreement and the possibility of carbon capture and storage on a cost-optimal Western European Power system plan and how is this affected by the modelling choice between linear programming and unit commitment?*

I-E-Energy minimises fixed and variable costs on an hourly basis, for a consecutive year. Inputs in the model are demand data from ENTSO-E, hourly renewable energy production capacity factors from Pfenninger and Staffell (2016) and techno-economic parameters from various literary sources on power system optimisation. The model calculates an optimal configuration of installed generation, transmission and storage capacity and an optimal generation mix at minimum system costs.

Powerfys minimises variable costs over a 36-hour rolling time window, continuing until a full year is reached. The model requires renewable energy production data, a predefined set of electricity generating units, fixed transmission and fixed storage units. It calculates the optimal dispatch of electricity generating units subject to technical constraints from thermal generators, such as start-up costs, ramping limits, minimum on/off times. To determine the optimal configuration of generation, transmission and storage capacity, I-E-Energy was run. The generation mix calculated by I-E-Energy was then compared to the dispatch calculated by Powerfys.

Three scenarios were evaluated. First, a 'business as usual' scenario was run with emission levels comparable to 2014 levels. This scenario serves as a benchmark for how the model would shape the system if no constraints were used. This is the reference scenario. Secondly, a scenario was run with a maximum CO_2 emission of 0.018 tonne CO_2/ MWh electricity supplied and without the possibility to implement CCS, consistent with a 96% CO_2 emission reduction. Lastly, a scenario was run with both the maximum emission constraint implemented and with the possibility to implement CCS.

I-Energy provides the fixed and variable costs of all three scenarios. As expected, the system levelised cost of electricity is lowest for the reference scenario at 48 €/MWh. The total generation capacity is 809 GW and is dominated by the cheapest possible option: coal fired generation.

A considerable amount of wind power capacity is installed, but this does not compare to the amount of coal fired power capacity. Therefore, deployment of transmission capacity, storage conversion and storage reservoir capacities remain limited: 36 GW, 55 GW and 460 GWh, respectively. The second scenario results in the highest levelised cost of electricity: 55 €/MWh. The emission reduction reduction is realised with a total generation capacity of 2034 GW. This scenario is dominated by solar PV and wind power capacity. To maintain stability of supply, a transmission capacity of 455 GW is installed, accompanied by storage conversion and reservoir capacities of 2034 GW and 6600 GWh, respectively. When CCS is available (third scenario) the system levelised costs are moderate: 51 €/MWh. The total generation capacity is 1453 GW, mainly because renewable energy capacity is partly replaced by a relatively smaller amount of coal fired generation capacity with CCS. The installed transmission capacity is 240 GW. Storage conversion and reservoir capacities are 118 GW and 1600 GWh, respectively.

Optimisation as a unit commitment problem with Powerfys results in higher operational costs. The reference scenario produces electricity at 49 €/MWh, a 2.6% increase. Generation is partly shifted from coal to gas fired generation, which can be explained by the stricter technical limitations inherent to coal fired generation, compared to gas fired generation. Implementing the emission constraint (second scenario) results in a levelised cost of electricity of 56 €/MWh, a 1.2% increase, which can be explained by technical limitations of gas fired power plants that are not taken into account in I-E-Energy. The stricter limitations for coal over gas power are again observed in the last scenario, with CCS implemented. The costs are 52 €/MWh, a 2.4% increase.

To conclude, the goals set by the Paris agreement increase system costs of the European power sector. Deployment of carbon capture and storage can moderate that increase. The modeling choice between linear programming and unit commitment affects the outcome: unit commitment increases overall costs. However, this increase is modest, which serves as confirmation that a linear modeling approach can be sufficient for answering a wide range of questions. To increase accuracy, one might integrate both models and provide a complete answer that integrates long time-spans and a wide variety of technical constraints.

Preface

This master thesis marks the end of the programme Industrial Ecology, a combined masters degree at the Delft Technical University and Leiden University. It also marks the end of my career as a student and will hopefully soon lead to the start of my professional career.

Before you start reading this thesis, I would like you to realise that this work would not have been possible without the contribution of several important individuals. First and foremost, I would like to thank my supervisor Remco Verzijlbergh. He provided the guidance that was required for me to finish this thesis. He has maintained a perfect balance between enthusiastically inspiring me to explore and pursue new opportunities and being pragmatic to make sure that performance was delivered. The fact that he took the time to read some of my work at night after a panicky call from me a few days before the deadline for my first version meant a lot to me. I was lucky to have a supervisor that has always been available and ready to help when needed. Secondly, I would like to thank my day-to-day supervisor Lou Ramaekers, who helped me through my daily struggles, who was ready to help basically at any moment, and more than once, became equally determined to find the answers to my research questions as I was. His contributions have been crucial at several moments, and have brought the quality of this work to a higher level. Furthermore, I would like to thank my second supervisor René Kleijn, for guiding the research into the desired direction and making sure I would keep thinking in the Industrial Ecologist mindset. His contributions made me take a more holistic view regarding the results of this thesis, which is quite important, considering the hours and hours of programming that have gone into it. Then, I would like to thank everyone at Ecofys B.V. for providing me with the opportunity to work there, have coffee and a budget that allowed me to completely focus on my thesis. At the exact time that I am writing this, my mother is sending me encouraging text messages. Maybe most important of all, I would like to thank my parents and sister, for without them, it would not have been possible at all to arrive at this point in my life.

Freek Zuiderveen Borgesius, December 2017

List of Figures

List of Tables

List of Abbreviations

CCGT Combined cycle gas turbine. 30

CCS Carbon Capture and Storage. 3, 5, 30

COP21 21st Conference of Parties. 1, 2, 6, 7, 23

CSP Concentrated solar power. 85

ENTSO-E European network of Transmission System Operators - Electricity. 9, 20

FC Fixed Costs. 29

FOM Fixed operation and maintenance costs. 29

IEA International Energy Agency. 2

INDC Intended Nationally Determined Contribution. 2

NIMBY Not in my backyard. 12

OTEC Ocean thermal energy conversion. 85

RES Renewable energy source. 16, 19

RES-E Renewable energy source. 18, 19

TSO Transmission System Operator. 9

VC Variable Costs. 29

VOM Variable operation and maintenance costs. 29

VRE Variable renewable energy. 17

Contents

Introduction

1.1 The Paris Agreement

The Paris Agreement is fair and just, comprehensive and balanced, highly ambitious, enduring and effective and with legally binding force.

China's Closing Statement at COP21, December 12, 2015

While there is still a fierce debate running in the United States Republican party on climate change, the rest of the world, together with 97% of climate scientists agree that climate change is real and the main cause is human activity (Cook et al., 2013). With the COP 21 treaty signed in Paris, the world has reached an unprecedented agreement to mitigate this climate change (Kinley, 2017). Succeeding this conference, 119 nations have promised to limit the average global temperature rise to 2 °C above pre-industrial levels.

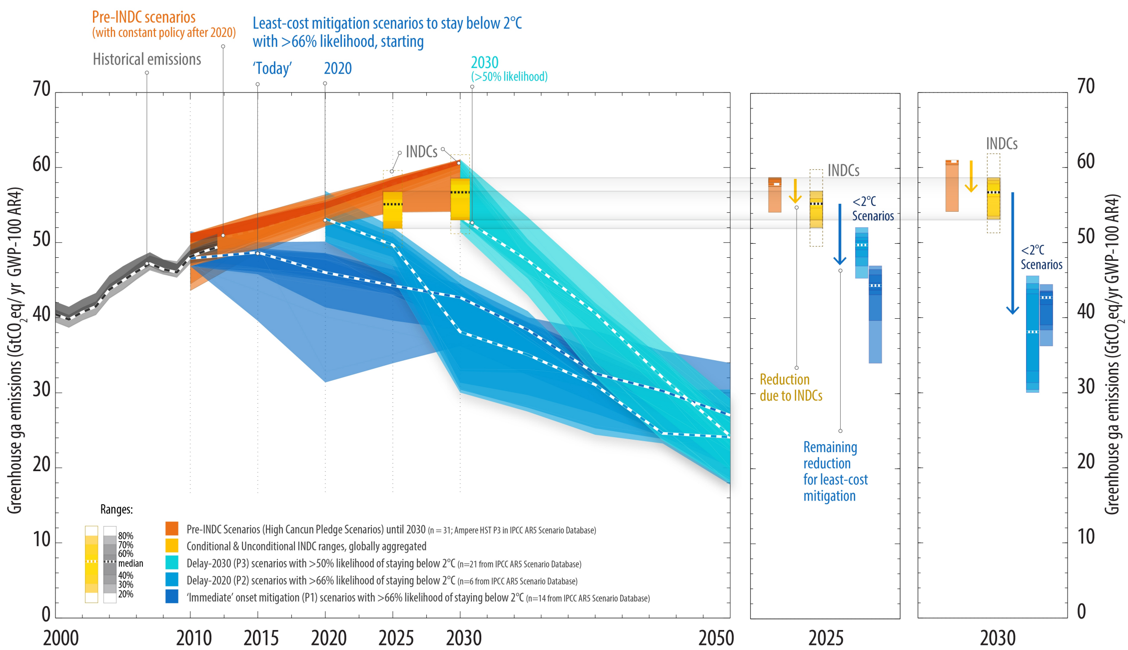

Figure 1.1: *CO_2 Mitigation scenarios as they are determined by the UNFCC. It shows the yearly Greenhouse gas emissions in Gton CO_2, both historically and future projections, whereby the future projections are pathways corresponding to mitigation scenarios with a certain likelihood.*

Figure 1.1 represents the yearly average greenhouse gas emissions corresponding to keeping the average global temperature rise below 2 °C above pre-industrial levels (from here onward referred to as the 2 °C barrier). The concentration of CO_2 in the atmosphere is cumulative, meaning that there is an absolute amount of CO2 that can be emitted before the 2 °C barrier will be reached. The world has a 'stock' of allowable greenhouse gases in its atmosphere, which means that every ton of CO_2 emitted at this moment will be subtracted from the stock and cannot be emitted anywhere in the near future again, without consequences. The figure shows several mitigation scenarios, clearly indicating that every delay requires a more rigorous future mitigation strategy.

Emission of anthropogenic CO_2, which is the most discussed Greenhouse gas, is the main cause of this temperature rise. The energy provided to the major sectors in the world predominantly comes from production and use of fossil fuels, which cause most of the CO_2 emissions in the world today. Mitigation of direct emissions by fossil fuel sectors is essential.

Whether it was because of the outstanding work by the French negotiations experts at the conference, the tragic events in Paris itself sometime earlier that month, or maybe the ever-increasing awareness of the gravity of the situation by all parties involved, one thing is certain: this unprecedented deal regarding climate policy exceeded everyone's expectation. It was considered a huge success and by some even seen as the only outcome that could save the world as it is today. However, while its success is widely celebrated and any other outcome could have led to a disastrous future, the follow-up on this deal might prove to be just as hard as the agreement itself: the blueprint for implementation of this deal has yet to be laid out (Christoff, 2016).

Ambition levels of the Agreement
One of the critical factors of success for the COP21 agreement was based upon "Intended nationally determined contributions" or INDC, which invited the separate countries to "pledge" their token of goodwill; their intentions on mitigation of climate change until 2030, which laid the foundation for the draft text of the agreement itself Christoff (2016). As illustrated in figure 1.1, the calculated effect of the measures determined through these INDC's, will not be sufficient to keep the Earth's temperature rise within 2 °C. The need for rigorous change becomes more urgent with every day of not implementing any serious mitigation measures. This was elegantly vocalised by Dr. Fatih Biro, Executive Director of the International Energy Agency: *"As we advance further into a post-COP21 reality, the gap between the goals of the Paris Agreement and efforts on the ground looms large. Actions to both achieve and surpass the INDC's will require a sophisticated, detailed analysis of key policy areas, which can help break the overarching task down into manageable pieces."* IEA (2016a).

This detailed analysis of key policy areas is provided by the International Energy Agency IEA. (also see fig. 1.1). The international energy (IEA, 2016a) agency distinguishes between four levels of ambition in the context of reaching the 2 °C barrier:

1. Implementation of NDC's, with a 50% probability to limit warming to about 2.7 °C in 2100, with higher temperatures thereafter if the same level of ambition is retained after 2030;
2. Deeper emission cuts involving near-term peaking of global energy-related emissions and are consistent with a 50% probability of limiting warming to 2C by 2100, which has been extensively analysed by the IEA in the ETP 2DS and the World Energy Outlook (WEO) 450 Scenario;
3. The increased ambition, newly established in Article 2 of the 2015 Paris Agreement, which resets the global goal to well below 2 °C;
4. the Agreements call to pursue efforts to limit the temperature increase to 1.5C, which existing analyses, though scant, indicate will likely move forward by one to two decades the date by which carbon neutrality will have to be achieved, compared with 2 °C scenarios, requiring further modelling and analysis.

In conclusion, the exact blueprint for reaching the 2 °C barrier is basically non-existent. Moreover, since all parties agreed on keeping their emissions within the 2 °C barrier and even what would classify as ”well below” that: at 1.5 °C, this leaves room for plenty of further research.

The Power sectors contribution and target
One of these four ambition levels has a 50% probability of limiting warming to 2 °C in 2050 (IEA, 2016a). This ambition level is extensively analysed in Energy technology perspectives (IEA, 2015) and in the World Energy outlook 450 scenario (IEA, 2016b). This ambition level will serve as a benchmark for this research. The route towards reaching this ambition level has profound consequences on the power sector. Of all energy-consuming industries, the power sector will undertake the largest share of emission mitigation. Within this ambition level, the power sector will be significantly decarbonised by 2050, producing only 1.4 Gton CO_2, compared to over 14 Gton CO_2 in 2015. The two studies predict that coal-fired generation without CCS is almost completely phased out and the share of gas-fired generation without CCS falls under 60% of total gas-fired generation. An important measure for the power sector is the measuring of carbon intensity (in grammes of CO_2 emitted, per kWh produced). The fact that carbon intensity is measured per unit of electricity produced, makes it suitable for modelling. Several sources have estimated the contribution of the European power sector required to abide by the Paris agreement. The numbers are presented in table 1.1.

Source	Area	Scenario	G CO_2 / kWh
Drummond 2014	Europe	Exiobase IO	31
Drummond 2014	Europe	GINFORS	25
Drummond 2014	Europe	ETM-UCL	-190
IEA 2016a	Europe (OECD)	2DS	18
IEA 2015	World	2DS	40

Table 1.1: *Carbon Intensity requirement consistent with a 2 °C temperature rise in 2100, for the world and for Europe.*

Table 1.1 show estimates of the carbon intensity of generation, under varying assumptions, predicted by different models. In order to stay below the 2°C barrier, the models predict that carbon intensity of generation should be somewhere in the range of those numbers. These figures give insight into the task at hand. While the power system has changed significantly over the past few years, it is still far from reaching that goal, with carbon intensities in 2013 levelling at about 550 g CO_2 / kWh produced (EEA, 2016).

1.2 Power Sector Solutions

The current power system operates under an important paradigm: security of supply must be guaranteed at all times. Should a disruption in the supply arise, the economic, social and political consequences would be disastrous (Lopes et al., 2007). Therefore, it is imperative that electricity supply is always guaranteed. Conventional power plants, such as coal and gas power plants emit fossil fuels. For a long time, these plants have been cheaper and more efficient in generating power. These aspects, together with maintaining the security of supply, were considered more important than the tonnes of CO_2 that were emitted into the atmosphere. Recent developments have shifted the focus more towards the negative side-effects in terms of global warming, causing the renewable energy sector to rapidly develop. Several countries around the world reported so-called ”decoupling” between economic growth and CO2 emission: the United States reported that CO_2 emissions from the energy sector fell by 9.5% from 2008 to 2015, while the economy grew by more than 10% (Obama, 2017). Gulf countries reported both absolute and relative decoupling (Salahuddin and Gow, 2014). However, renewable energy generators have serious limitations compared to conventional power plants, these are discussed in section 1.2.1.

1.2.1 Renewable energy and Intermittency

Where conventional power plants can be turned on at will, this is not the case for renewable energy. Generation of power from renewable energy sources is unfortunately dependent on weather conditions. Therefore, renewable energy sources are both subjected to variations in weather patterns and their unpredictability. At low penetration levels, the electricity system is able to deal with these characteristics. At high penetration levels, however, some challenges arise. Brouwer et al. (2014) identifies several main challenges that need to be overcome. For generation technologies with variable output to deliver a steady power supply, reserve capacity is needed, 2) renewable energy generation "gets in the way of" thermal generation (i.e. in favourable conditions, IRES out-competes thermal generators) and technical limitations of the power system lead to curtailment of renewable energy sources. To overcome these challenges, a range of solutions has been proposed (see chapter 2 for a detailed analysis of literature). The main solutions are discussed in section 1.2.2 and 1.2.3.

1.2.2 Storage and Transmission

There are several options available to solve the intermittency problem. Some are more costly than others, but other factors come into play as well. Basically, there are two options to prevent significant overcapacity requirements: grid integration and storage. The two options can be considered technically complementary and economic substitutes (Van Staveren, 2014).

Storage
According to Spiecker and Weber (2014) and Brouwer et al. (2014), high amounts of intermittent renewable energy sources are likely to be installed in the future European Energy system, but the system has to be balanced. This implies that there is a requirement for quickly adjustable back-up load, capable of scaling up and down in the case of peaks and valleys in wind and solar power, achievable through backup power plants (e.g. Gas) or storage units (Roadmap, 2010). The current power system can cope with a reasonably high share of renewables. For example, a recent case study on the German power system showed that up to 50% RES could be met without storage (Weitemeyer et al., 2015). However, that same case study pointed out a requirement for either back-up adjustable power plants or storage units for higher (80%) RES integration scenarios. Brouwer et al. (2014) found that novel technologies such as energy storage should play a role in the future energy system.

Transmission
Weather patterns vary across the European continent. If all Europe's windmills would be planted in the North sea, calm weather in that area could lead to serious generation valleys. The same goes for solar energy, a depression in a single area could have significant effects. By integrating grid over larger areas, weather patterns can level out more evenly over larger areas, relative to smaller connected areas. From an economic perspective, grid extension can homogenise and stabilise electricity prices for baseload generators (Schaber et al., 2012b). For large shares of RES integration, transmission network integration becomes more valuable, for they are the source of the need for balancing. Extending the grid to a pan-European grid transmission network significantly reduces the required generator capacity for grid balancing and backup power (Rodriguez et al., 2014).

1.2.3 Carbon Capture and Storage

Carbon capture and storage (CCS) techniques are likely to play a role in reducing GHG emissions to the desired level of the Paris agreement. (IEA, 2016a) estimates the role of bioenergy with CCS at about a quarter of all CO_2 captured in 2050, about 1 Gton. While this technology is not yet widely applied in current electricity generation practices, its implementation in the future electricity system can be extremely valuable. Especially in during periods of low energy yield from intermittent renewables, it provides an opportunity to remain fulfilling demand. Moreover, when CCS is combined with biomass combustion, the net CO_2 emissions can turn **negative**. Also, when CCS is applied in combination with coal-fired power plants or gas turbines, CO_2 emissions are significantly reduced.

1.2.4 Limits to Power sector Modelling

Gaining insight into the workings of the power sector and its components is mostly done through modelling. The multitude of components involved in power systems in combination with the many influences that they are subjected to, makes it hard to make accurate models of reality. Modelling many components increases complexity, thereby increasing computational power requirement. As a result of this, the researcher is forced to make concessions (Ortner, 2014). This trade-off is illustrated by the scale represented in figure 1.2. A manageable model requires simplifications. Most earlier work separates between a high temporal resolution with low spatial resolution or vice versa. To this extent, either linear programming models or mixed integer and unit commitment models are used. Linear modelling is particularly fit for modelling longer time periods, which is beneficial to accurately model investment decisions in renewable energy. Linear models are capable of limited spatial resolution (restricted to countries or regions as a whole). Mixed integer programming allows for high accuracy modelling. As a concession, they are usually not capable of modelling longer time periods.

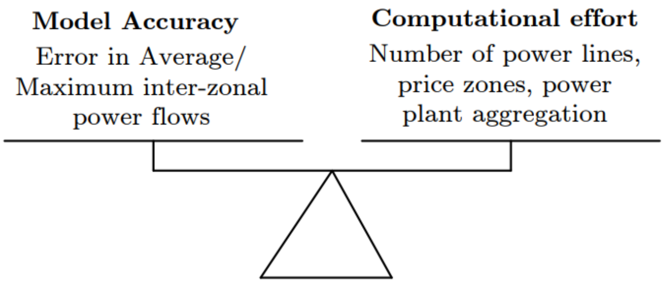

Figure 1.2: *Trade-off decision to be made for large scale power system models (Ortner, 2014)*

1.3 Research Objective

The impact of intermittent renewable energy has been discussed in depth in numerous published works (Spiecker and Weber, 2014). The elements of storage and transmission and the extent to which they are complementary has been researched in depth by(Van Staveren, 2014). The extent to which renewable energy can be integrated without the need for storage is determined by Weitemeyer et al. (2015). Rodriguez et al. (2014) investigate the effect of wind and solar on transmission and balancing needs. The question to whether the electricity system's design should be planned on a regional, national or local level is investigated by De Pater (2016). Carbon capture and storage technology will play an essential role in the future energy system, according to the IEA (2016a).

All of the elements discussed above impact the electricity system and the future electricity systems extensively; all affect the others to an extent that they cannot be viewed individually. An integrated approach is required to acquire insight into the electricity system of the future. The COP21 Paris agreement sets certain requirements for different sectors, as can be seen in 1.1. The COP21 treaty encompasses the whole world and all aspects of emissions. It is therefore relevant to study the combined effects of the earlier mentioned trends on the future electricity system. It is also relevant to see how the COP21 treaty affects the future energy system.

The larger question that lays ahead is how to design the energy system in such a way that the goals of the treaty are met in time and what is the most cost-effective way to get there. This requires an integrated approach. The main work on which this research is based, De Pater (2016) has done this as well. He studied the effect of central vs decentralised planning under different renewable energy penetration scenarios. To this end, he constructed a linear system cost optimisation model, that incorporated generation technologies from three different dispatchable power plants, two types of RES-E, a number of storage options and a cross-border transmission network. However, the work by De Pater considers an optimal energy system with80% renewable energy. While this would be a terrific start for a European system design, this requirement might not be strict enough. Implementing a renewable energy obligation might also be less cost optimal than desired. The German Energie-Wende is one of the examples were stimulating a development like that has cost a lot of money without cutting back on emissions much (Beveridge and Kern, 2013). Also, this work does not consider carbon capture and storage technologies, which are essential in a 2°C scenario, according to the International Energy Agency.

Additionally, the field of power sector modelling considers mostly high accuracy models in small areas, low accuracy models in large areas, or simplified approaches where certain elements of the energy system are predefined. However, in order to accurately model the future energy system and gain insight in the low-carbon energy system of the future, insight into both areas is required.
The objective of this research will be to find a solution for the cost-optimal energy system design that is able to emit CO_2 emissions in consonance with limiting the temperature to 2°C in 2050 with a 50% probability, while simultaneously investigating the role of carbon capture and storage within that system. Furthermore, the effects of technical constraints that would limit thermal power plant generation are investigated. The model by De Pater will provide the basis for the desired extension in this research. However useful this model is, due to its structure it does not allow for easy modification. This research requires extension and restructuring of the model. Furthermore, for the purpose of potential integration with future work, the model should be translated from Matlab to Python. This model, translated to Python, is a linear programming optimisation model with a high temporal, but low spatial resolution. In order to gain insight into the limitations of this model in terms of spatial resolution and technical constraints, this model is compared to Powerfys. Powerfys is a unit commitment model, with a high spatial, but low temporal resolution. A comparative analysis between both models gives insight into the full picture of the energy system of the future, abiding by the Paris climate agreement.

1.4 Research Questions

The research objective stated in the paragraph before leads to the following research question:

What is the effect of the goals set in the Paris agreement and the possibility of carbon capture and storage *on a cost-optimal Western European Power system plan and how is this affected by the modelling choice between linear programming and unit commitment?*

The goals set in the Paris agreement can be adapted to goals that specifically target the European power system. The power system plan refers to the set of specified generation, storage and transmission capacities that satisfies the requirements that are specified in the model design. This research question is still very broad and leads to a series of sub-questions. The combined answers to the sub-questions lead to the answer of the main research question. The sub-questions are formulated as follows:

1. How do the COP21 treaty agreements translate in requirements for the European electricity system?
2. Which conventional generation technologies, storage options and renewable energy sources, both currently installed capacities and 2050 projections, impact the current, or have the potential to impact the future energy system?
3. How can the linear system cost optimisation model by De pater (2016) be reprogrammed in Python, while maintaining computational performance?
4. What is the financially optimal solution in terms of generation technologies, transmission, and storage, subject to the COP21 constraints?
5. How do technical constraints such as ramping limits, startup costs and minimum generation requirements affect the systems operational cost?
6. How do technical constraints such as ramping limits, startup costs and minimum generation requirements affect regional distribution of generation, storage and transmission of electricity?

Theoretical Background

This chapter discusses the Electricity system in section 2.1. The role of carbon capture and storage in our current and future electricity system is discussed in section 2.2. The theory used to model the electricity system is discussed in section 2.3. The relevant literature is discussed in section 2.4. The relevance of this thesis with respect to Industrial Ecology is further elaborated on in section 2.5.

2.1 The Electricity System

To understand the implications of the outcomes of this research in the larger context of the totality of the electricity system, a short introduction to the functioning of the electricity system is required. This section provides a short explanation of the physical attributes and the actors in the electricity system and their functioning upon each other.

2.1.1 Physical Attributes in the Current Electricity System

The physical layer of the electricity system can be roughly divided generation, transmission, consumption and storage. Together, these attributes enable the grid to ensure a stable supply of electricity. Recent developments pose challenges to the physical structure of this grid. These are shortly discussed.

The electricity system is large, complex and expensive, it is characterised by stability, lock-ins and sunk costs. Transitions of these types of systems are inherently difficult (Verbong and Geels, 2010). Electricity was traditionally generated by a centralised system, where large power plants provided the bulk of the electricity supply using large thermal fossil fuel power plants. However, this has changed in recent years, due to increased pressure from the public and legislators to pursue a green agenda. The focus has shifted more and more towards decentralised generation: smaller power plants, consumers that install solar panels and becoming ”prosumers”, delivering power back to the grid. This increases the need for grid flexibility.

Also, the availability of cheap renewable energy sources on a large scale has put pressure on the grid. Due to its dependence on weather conditions, renewable energy sources are an unstable source of electricity. Weather patterns change according to seasonal, daily weather patterns. Its power supply is therefore variable. Moreover, weather patterns are hard to predict. This makes renewable energy sources unpredictable. Both variability and unpredictability put pressure on the electricity system and require grid flexibility.

Physically, the grid flexibility requirements can be solved by expanding the transmission grid, introducing storage options or creating reserve capacity. Increasing transmission can distribute flexibility requirements and demand fluctuations, levelling both to balance the grid. Storage capacity serves as a buffer, to provide power in times of need. Backup plants provide extra power and can be turned off when needed.

2.1.2 Actors in the Electricity System

Power is generated by electricity producers. Companies such as Vattenfall, E.ON and EDF group produce electricity usually through large power plants. These companies are referred to as 'load serving entities'. Their produced electricity is sold on several platforms, such as the spot market, or through bilateral contracts. They trade on these markets by selling their power in 'blocks': certain amounts of electricity against a certain price. The electricity price that they offer always approaches their marginal costs: everything they sell above marginal price is generates some income. The order of generation types is therefore mostly fixed: renewable energy has zero marginal costs, gas plants have high marginal costs. This order is known as the "Merit order".

Consumers are the buyers of electricity. Consumers are roughly divided into small consumers and large consumers. Large consumers can directly trade on the market, small consumers buy from retail companies. The producers can also sell to large consumers and through bilateral contracts, but not directly to consumer. The bids are then placed in order from low to high, the offers are placed in order from high to low and the price at which they meet is the electricity price.

The national distribution of power is regulated through the transmission system operator (TSO). This entity (in The Netherlands this is Tennet) is responsible for balancing the grid and preventing blackouts. The electricity markets provide information about the electricity requirements in the days, hours or minutes to come, depending on the type of market. To prevent a blackout or overloading of the system, the TSO has to balance the grid. To this extend, the TSO requires a certain amount of flexibility in the grid, such as the availability of storage, the possibility to transfer electricity to other areas in the grid or a backup power plant, that can be turned on or off as the TSO wishes.

Regional distribution is regulated by an entity called the distribution system operator (DSO). Mainly, the regional distribution consists of the grid that is below ground, such as the power flows to residential areas. As well as the TSO, the DSO is a publicly regulated company, which is not allowed to compete on the basis of infrastructure. In most countries, there is one national TSO, but several DSO's.

To encourage liberalisation of the Electricity and gas markets, the European Network of Transmission System Operators (ENTSO-E) was established. This entity has legal mandates and works to optimise and integrate electricity markets within the European Union. As stated before, the national TSO requires flexibility to balance the grid. To this extent, the ENTSO-E facilitates cross-border trade and prepares for the challenges brought about by the changing power system. The role of ENTSO-E is becoming more and more important as power flows become more internationally focused.

2.1.3 The Electricity System as a Socio-technical System

Socio-technical systems theory dictates that technological systems or innovations do not operate in isolation, but their functioning is heavily interconnected and dependent on the environment that they are embedded in. Socio-technical systems theory teaches us that when studying technological systems, the social context should always be taken into account. Socio-technical system are described by Geels (2004) and contain several key elements: the production and use of a certain technology, the linkages between elements of that technology and the link to the deployment of resources to fulfil a societal function. This concept has been further specified towards infrastructures (as technology) and the connected institutions (as societal functions) by Künneke et al. (2010).

The power sector has been mentioned as an example of such a socio-technical system (Geels, 2004; Künneke et al., 2010; Verbong and Geels, 2010). The physical attributes that are discussed in section 2.1.1 form the technological part. The social elements are the institutions built around them with the purpose of fulfilling a societal function, such as spot markets, bilateral contracts and regulatory entities.

Linkages between technical elements are physical (the transmission grid), but also monetary (e.g. electricity markets) and social (e.g. perception of available electricity at all times). A smooth interrelation between technology and institutions is not always self evident. Künneke et al. (2010) studied this interrelation with a view of institutional reform of electricity markets, and concluded that with these reforms, certain technical elements were neglected by the institutions. This led to "inferior performance" of the technical system, even to blackouts. Congruent to Geels, they continue to stress that infrastructures (thus the power sector) should be studied in concert with their institutional environment. If this is not done properly, they argue, restructuring infrastructures without taking into account the interplay between their relevant institutions will result in failure of technical system services (e.g. stability of supply) and increased system costs due to inefficiency.

This research focuses mainly on the physical attributes of the electricity system and the related costs. The modelling approach that is chosen (further elaborated on in section 2.3.1), automatically excludes certain institutions (such as electricity markets). The scope of this research does not allow for extensive research regarding the complete institutional environment of the electricity system, it rather focuses on technological accuracy. Therefore, it is important to reflect on these simplifications and realise the limitations that the results might have when viewed in the larger context of socio-technical systems theory.

2.2 Carbon Capture and Storage

The Dutch Government recently introduced the coalition accord, which sums up several options to mitigate CO_2 emissions. The most significant measure that is expected to be implemented is the use of carbon capture and storage. If carbon capture and storage technologies are combined with traditional thermal power plants, they provide interesting grid balancing and flexibility options complementary to renewable energy technologies. However, the future of these technologies yet remains uncertain, as large scale commercialisation stagnates. This section elaborates on carbon capture and storage technologies as a complementary option to achieve emission reduction goals without increasing pressure on the electricity system. It further discusses the limitations of the technology.

2.2.1 The Process: Capture, Transport and Store CO_2

Carbon capture and storage is a three step process. First, the CO_2 is captured from the combustion process, it is then transported to a suitable location where it can be stored safely. Roughly three main types of CO_2 capturing technologies can be identified: Post combustion, pre-combustion and oxyfuel CO_2 capture. All three have their advantages and disadvantages. Leung et al. (2014) provide an overview of their characteristics. Figure 2.1 visualises the three options.

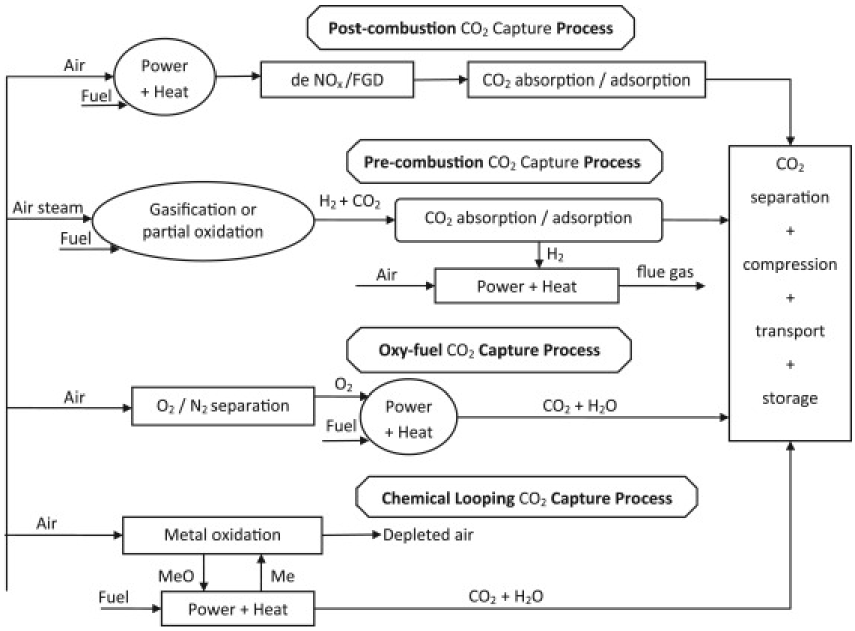

Figure 2.1: *Overview of CO_2 capture technologies, showing combustion processes under the influence of post-combustion capture, pre-combustion capture and oxyfuel capture (chemical looping is not relevant to this research). Figure is reprinted from Leung et al. (2014).*

Post combustion CO_2 capture refers to CO_2 removal from post-combustion flue gas. This technology is the most mature of all three technologies and is particularly suitable in existing power plants because of its relatively limited hardware reconstruction requirements. Its CO_2 removal ability is feasible on a small-scale. A challenge that remains is the required stand-by power ('parasitic load'): the remaining flow is large and induces large transportation and storage costs.

Pre-combustion refers to treatment of CO_2 before combustion takes place. Depending on the generation technology, this process differs (see fig 2.1). In the case of coal fired power generation, syngas is formed through gasification of fuel in the presence of a limited amount of oxygen. Through CO_2 absorption, the syngas is cleaned, producing H2 gas and separating CO_2. Subsequently, H2 is used for power generation. Natural gas is directly reformed to H2 and CO, but the rest of the steps are similar to coal pre-combustion treatment.

oxyfuel capture refers to combustion in the presence of Oxygen instead of air. Oxygen does not contain nitrogen, which enables easy separation. The only remaining particles in the waste stream are H_2O, CO_2, SO_2 and some small particles, the latter two are easily removed. This process also significantly reduces the amount of NOx in the waste stream and the concentration of CO_2 remaining is high. A downside is the requirement of an air separation unit that requires a significant amount of energy.

Post-combustion and oxyfuel capture are versatile: both are applicable to both gas and coal, whereas pre-combustion CO_2 capture is mainly used in coal-gasification plants. Costs for all three technologies were compared by Gibbins and Chalmers (2008) who found that for coal plants, pre-combustion capture is the cheapest technology, post-combustion and oxyfuel were similar. Capture of CO_2 from gas plants was cheapest for post-combustion. Additionally, post-combustion is the least efficient because of its energy penalty (refers to the additional energy required to capture CO_2).

The CO_2 that has been captured, is then compressed and transported to a storage site. CO_2 can be transported in several ways. To this end, mostly pipelines are used for large volumes. However, railroad and ships are more competitive for smaller volumes. Depending on the carrier type, CO_2 is transported either in a supercritical or liquid state. Their has been some critique regarding the environmental safety of these hazardous truckloads and pipelines.
Geological storage is the most common way to store CO_2. CO_2 may be stored in abandoned gas fields or deep saline aquifers, or in oil reservoirs. Depending on the location, a geological storage site has the capacity to store several tens of million tonnes of CO_2 (Doughty et al., 2008).

2.2.2 Issues with Carbon Capture and Storage

Carbon capture and storage technologies have been subject to debate. While CCS has proven to be technically feasible, it has not yet been widely deployed. Earlier predictive models have overestimated the adoption of CCS technologies. Environmental, societal and financial concerns have hampered the advance of widespread CCS adoption.

Environmental concerns are mostly centred around the possibility of leakage from geological storage sites, either back through the surface, or into freshwater basins. If CO_2 were to reach the surface in the form of a so-called "CO_2-plume", it could prove fatal. In 1986, a sudden eruption of a CO_2 reservoir at Lake Nyos killed 1745 people, along with everything that lived in a 14 km radius. However, this was a natural disaster that occurred in an area that was not monitored. According to a study about the social acceptance of CCS, performed by Van Alphen et al. (2007), environmental NGO's and governments view the risks as manageable, since most technical knowledge required is similar to current oil and gas practices. This view is confirmed by a dissertation by Bakker (2017).

Social Acceptance of CCS technologies on land proves to be more difficult. For example, a Dutch effort to store CO_2 underneath a residential area near Rotterdam, failed over lack of approval from the public. Clear reasons for the public to have a reluctant attitude towards CCS are absent. Van Alphen et al. (2007) ascribe the concerns to the fact that the technology is largely unknown to the general public, which leads to resistance. For fear of danger or inconvenience can result in the "not in my backyard" (or NIMBY) type of opposition, where residents believe that CO_2 should be stored further away from their homes. Storing CO_2 beneath sea beds would resolve this issue, but could lead to environmental concerns, such as acidification of seawater and disturbance of ecosystems (Gibbins and Chalmers, 2008).

While technical feasibility has been proven, the economic viability may pose a greater concern for those in favour of implementing it on a large scale. The large CO_2 producing coal fired power plants in the port of Rotterdam were supposed to be accompanied by plans to store CO_2 underneath the nearby seabed, but electricity companies Uniper and Engie ended the contracts for financial reasons. The main reason for the current tampered growth of CCS technology has been financial. According to Gibbins and Chalmers (2008) costs will decrease in the future, but 2050 projections are hard to accurately estimate. Moreover, current energy modelling literature is not conclusive about the role of CCS in the future electricity system. Some do not even take the possibility into account (Brouwer et al., 2016; Bussar et al., 2016; Spiecker and Weber, 2014). Some energy models employ carbon capture but leave storage of CO_2 out of scope (Bertsch et al., 2012), while other research does incorporate costs for storage (Schröder et al., 2013). Costs for transport are highly dependent on design choices for specific sites. Whether or not existing pipelines are used instead of constructing a new infrastructure will significantly influence costs. The ranging cost estimates, together with the lack of consistency in modelling choices, makes prediction of technology adoption of CCS difficult.

While there are still many uncertainties about the adoption of CCS, if human kind continues with its current energy consumption patterns, the only way to keep the earth's temperature close to the desired level of the Paris agreement, involves CCS IEA (2016a); De Koning and Deetman (2014). However, when integrating CCS in predictive models, one should provide insight into the consequences of higher and lower costs trajectories for CCS technology, while simultaneously realising that the technical potential for storage of CO_2 might not be the real potential. Furthermore, assumptions about social acceptance of CCS should be made explicit.

2.2.3 Does Biomass with CCS really lead to negative Emissions?

The advantage of CCS is its possibility to mitigate emissions from fossil fuels. It allows thermal generation plants to remain operational under tight emission constraints. When combined with biomass plants Burning biomass, the emissions can turn negative. Burning biomass recycles carbon that was already in the carbon cycle, which means that no new CO_2 is added to the atmosphere. If the CO_2 were to be captured instead of released to the atmosphere, the net emission can turn negative: trees capture CO_2 from the air, the tree is burned, the emissions are stored underground. This process is illustrated by figure 2.2.

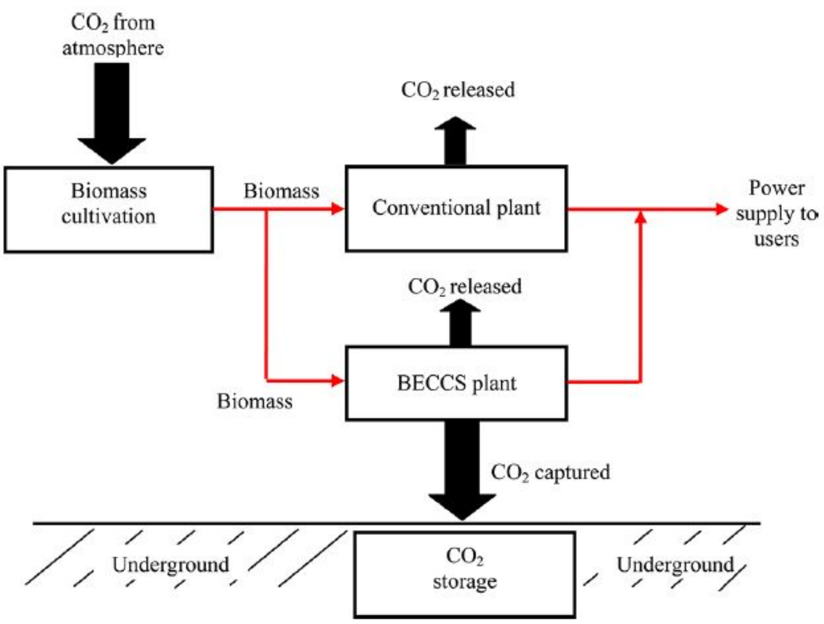

Figure 2.2: Visual representation of the Biomass to energy chain, combined with carbon capture and storage. Figure reprinted from Ooi et al. (2013)

Theoretically, utilisation of biomass should lead to negative emissions. In practice, this might be harder to achieve. Specifically, the extent to which these emissions are really negative, is openly discussed. As for all CCS technologies, immaturity of the technology are a cause for uncertainty to many parameters, such as a clear determination of the energy penalty involved in the capture, transport and storage chain (Marx et al., 2011). A study by IEAGHG (2009) found negative emissions to be -1743 g CO_2/MWh electricity produced. However, Rhodes and Keith (2005) found positive emissions of 200 g CO_2/MWh for biomass with steam reforming.

While consensus on specific values is still to be reached, the majority of literary works find negative emissions for biomass with CCS. A comparative literary assessment by Gough and Upham (2011) found Rhodes and Keith to be the only author that found positive emissions, regarding a specific processm, which was published in 2005. Technology development increases negative emission potentials through efficiency increases. Nevertheless, the uncertainty of the exact value of negative emissions should be considered when integrating negative emissions in power sector modelling.

2.3 Energy Systems Modelling

Now that the setting in which the research objective resides has been explained, the scope is narrowed to adequately answer the research questions. From the start, it has been clear that a model is required. This section shortly describes the group of models relevant models to answer these types of questions in section 2.3.1. within the best suited model class, the models used for this research are elaborated on in section 2.3.2 and the limits that those models have in the context of electricity systems in section 2.3.3.

2.3.1 Classification of Energy System Models

The energy system is a complex and interesting system, which has been subject to extensive research. Jägemann et al. (2013) distinguish between two main categories: Top-down macro-economic and bottom-up energy/power sector models. Following Jägemann et al. (2013), macro-economic models are characterised by 'high aggregation levels', in which details on technology and small regions to the extent that this research requires, are generally not included. Macro-economic models are generally used to study the effects of one economic sector on other economic sectors. Bottom-up power sector models can be subdivided into two main categories: simulation models such as agent-based models or system dynamics and optimisation models. Generally, these two types of models allow for a high level of detail regarding the data on technology production and its associated costs. Simulation models simulate the results of individual decision making, whereas optimisation models operate from the assumption of a single agent (planner). They calculate the optimal objective function over a predetermined time-horizon and resolution, subject to constraints for demand, ramping, capacity etc.. System cost minimisation models operate from the assumption that the demand is inelastic, thus independent from price fluctuations. If demand is considered elastic, the optimisation problem turns into a welfare maximisation problem, where both demand and supply can be changed. 2.3 gives an overview of the different types of energy system models according to Jägemann et al. (2013).

While changes in future demand are included as demand projections, they are not optimised in relation to the load. Demand is considered inelastic. Therefore, this research classifies as System cost minimisation. This simplification allows for cross-sectoral effects to be included without losing technical and regional detail.

2.3.2 Unit Commitment and Linear Programming

System costs minimisation models fulfil a certain requested demand using available electricity generation technologies. The goal is to minimise system costs, without violating the imposed constraints, such as transmission, generation, or storage constraints Conejo et al. (2006). Several methods exist to adequately perform this task on an hour-to-hour basis, each with their strengths and weaknesses. Two of these methods are relevant to this specific research: Economic dispatch using linear programming and the unit commitment problem. Both seek to

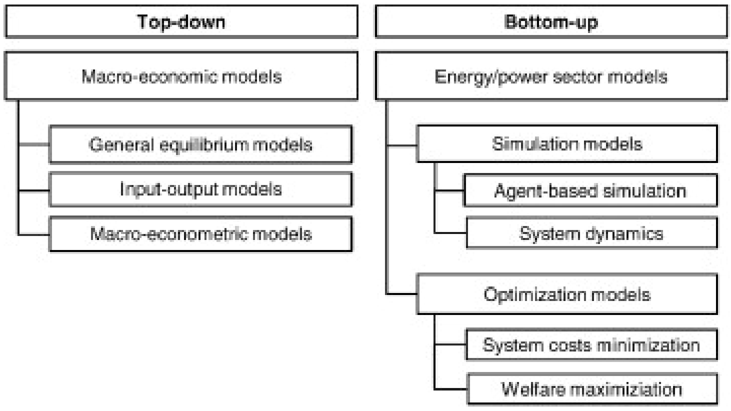

Figure 2.3: *Classification of energy system models showing the class and regime that optimisation models belong to (Jägemann et al., 2013).*

optimise system costs, subject to several constraints.

Linear Programming is the simplest form of optimisation problem (Conejo et al., 2006). Because only linear functions are included, optimisation methods remain simple and short. The number of options are not exponentially multiplied through binary or integer variables and optimal solutions can be found at the corners of the feasible area, demarcated by linear functions. The advantage of linear optimisation problem clearly is in its simplicity. However, questions arise to whether a linear model provides an accurate representation of reality: one cannot construct 1.5 power plant. Nevertheless, the linear programming method has been exploited for modelling of the power system (Ashfaq and Khan, 2014; De Pater, 2016; Brouwer et al., 2016). However, using these method, one has to sacrifice certain technical constraints (the specific technical constraints are further elaborated on in section 3.1.3.

Unit commitment describes a more complex optimisation method that allows for accurate modelling of generation units. IT comprises of determining the cost-optimal dispatch of available generation units and respecting the technical (or economic) limits of those generation units (Tseng et al., 2000). Therefore, the problem includes binary variables for generation units allowing for constraints such as spinning reserves, startup costs and minimum on/off times to be incorporated. The practical utilisation of the unit commitment problem for longer time-horizon becomes problematic: computation time grows exponentially with increasing problem size (e.g. longer time-periods). Therefore, unit commitment is confined to solving short time periods, rendering the option optimising for seasonal storage impossible.

2.3.3 Limits To System Costs Minimisation in the Larger Context

This research narrows the scope to techno-economic research. This means that the institutional context is taken into account only to a limited extend (e.g. creating electricity producing and consuming regions, central planning). Narrowing the scope is essential to every research. However, when doing this, one must keep in mind that such simplifications can have consequences on the results. Therefore, the results obtained through this research should be reflected on from a systems view, placing the results in context to its environment.

Künneke et al. (2010) warns that restructuring infrastructures such as the energy sector but without paying attention to the interplay between institutions and technology, will lead to failure. In essence, this means that directly implementing the results that follow from this research will exactly do that. This does not mean that this research is useless, however. The functionality of the outcome of this research is neatly summarised by Jebaraj and Iniyan (2006), who states that the formulation of policy should happen based on a discussion of the results of these model studies, but not on the results exclusively. The model outcomes serve as a basis for discussion.

2.4 Discussion of relevant literature

The literature review discusses relevant published works and literature, regarding the subject of this thesis. The literature review is considered to be a summary of the field of study that supports the identification of the earlier defined research questions (Rowley and Slack, 2004). The literature review loosely follows the structure of a systems approach to literature reviews by Levy and Ellis (2006), adjusted to fit the structure of this research. The relevant steps are:

- Identify major concepts relevant for research;
- Relate careful selection of literature to these concepts;
- Analyse critical information from literary sources;
- Critical review: synthesise and evaluate literature.

The relevant concepts were partly elaborated on in the introduction of this research, in section 1. In short, the concepts relevant to this study are optimisation models that model the effects of the integration of renewable energy sources (RES), considering generation, storage and/or transmission extensions. Furthermore, the effect of carbon capture and storage is a focal point of this study. A careful selection of available published works was made using a series of search strings and Google scholar, which led to the selection of 14 relevant types of research. The following search strings were used:

- ”Power system Planning” / ”Expansion Planning” / ”optimisation”
- ”Renewable energy Integration” / ”Renewable energy” / ”RES” / ”Wind & Solar”
- ”Europe” / ”European electricity grid”
- ”Carbon capture and Storage” / ”CCS”
- 2050 / future

The following table relates the selection of literature to the identified relevant concepts.

ID	Relevant published works	RES	Storage	Transmission	CCS
1	Spiecker and Weber 2014	X	X	X	
2	Huber et al. 2014	X	X	X	
3	Rodriguez et al. 2014	X		X	
4	Schaber et al. 2012a	X		X	
5	Jägemann et al. 2013	X	X	X	X
6	Schaber et al. 2012b	X			
7	Bussar et al. 2014	X	X	X	
8	Weitemeyer et al. 2015	X			
9	Schmid and Knopf 2015			X	X
10	Steinke et al. 2013	X	X	X	X
11	Brouwer et al. 2016	X	X	X	X
12	Gils et al. 2017	X	X	X	
13	Haller et al. 2012	X	X	X	
14	De Pater 2016	X	X	X	
15	Van Staveren 2014	X	X	X	
16	Verzijlbergh et al. 2014	X		X	

Table 2.1: *Relevant concepts and Related Research, discussing all articles relevant to this research. The subjects discussed are intermittent renewable energy sources ((I)RES), storage, transmission and carbon capture and storage (CCS).*

The electricity system has been studied through a wide variety of power system and cost minimisation models. As stated earlier, this literature review only contains optimisation models that include integration of renewable energy sources. The importance of grid extensions to balance increasing amounts of fluctuating renewable energy is recognised by many studies. Rodriguez et al. (2014) use a linear optimisation model with a 100% wind and solar PV penetration level, to determine the upper limit of flexibility reduction that can be reached by extending the transmission grid. Through modelling of both constrained and unconstrained interconnectors, they discover that balancing needs can be reduced from 24% to 15% of annual electricity consumption. While this upper limit gives an important insight into the boundaries of the potential benefits of transmission grid extensions, the optimal transmission capacity remains unknown in this study. This optimal transmission capacity is studied by Schaber et al. (2012a) who found cost-optimal grid extensions through a linear cost optimisation model for the European Union, for renewable energy integration in 2020 scenarios. Their research also includes the implications for electricity markets and baseload generators. They argue that inadequate capacities lead to high inequalities in Europe concerning utility revenues and that adequate international transmission grid extensions are advantageous for the base load as well as for variable renewable energy (VRE) plant owners. Schaber et al. (2012b) investigate these advantages further and quantify these advantages. They show the effects of grid extensions as a function of penetration of wind and solar, using a 2-dimensional parameter space. They find that grid integration can alleviate some pressing burdens in terms of required backup power, overproduction and storage requirements. They find that the costs of grid integration remain below 25%, at about 6/ MWh. Since the focus of their study was on the cost of transmission, only one type of storage was included (pumped hydro storage). These studies provide valuable information on the role of grid extension, but they do not give any information on the trade-off between storage and transmission, or their complementariness. They do acknowledge that this might be an area for further research.

The combined effects of storage and grid extension are investigated by Steinke et al. (2013). They quantify backup energy demand in a 100% renewable energy scenario, using a linear system cost optimisation model. Their fairly simple model includes grid integration and storage. The outcome, however, is quantified as a certain demand for backup energy, but some crucial constraints for optimisations are not included. Also, only one type of storage was included. A more extensive research was conducted by Van Staveren (2014). He investigates the role of storage in a European electricity system. He uses a clustered unit commitment model with three central nodes; a Southern, Central and Northern European node. His focus is on the value of electrical energy storage first, he finds that variable cost savings achieved through storage options increase when a higher share of RES is introduced to the grid. When further increasing RES he finds that transmission grid extension negatively influences the value of storage, leading him to conclude that after a certain level of renewable energy generation, the two options become economic substitutes. The argument that storage and grid extension help solve problems of intermittency at low cost, made by Van Staveren (2014), is confirmed by many. Huber et al. (2014) use an optimisation model to link Wind and Solar PV integration with grid flexibility needs at different temporal and spatial scales. They conclude that flexibility needs are reduced through a larger system size, therefore increasing the grid's capacity to successfully balance load fluctuations from renewable energy sources. Haller et al. (2012) also find that emission reduction targets of 90% in 2050 can be reached at only moderate costs. Using a cost minimisation modelling tool they show that this can be done when generation, transmission and storage capacities are expanded significantly.

The conclusion that grid extensions and storage are economic substitutes is found in other literary works to a certain extent. However, for a cost-optimal energy system, the question is raised which one is the most economically favourable option. Several studies investigate this question under different scenarios. Jägemann et al. (2013) determine optimal generation capacities and grid extensions through the use of an iterative optimisation model, including a market model and load flow analysis. In their model, utilisation of favourable RES-E sites is modelled as unconstrained, allowing for full exploitation of RES-E sites. They find that almost all generated electricity that exceeds local demand is transported (i.e. favouring grid extension) in a cost-optimal configuration. Their research confirms that grid extension and storage can be used interchangeably, but grid extensions enjoy a high preference over storage, from a financial point of view. De Pater (2016) conducted an extensive research on the question of central planning vs. regional planning in Europe, using a linear optimisation model. This study includes both storage and transmission, under several renewable energy penetration scenarios. He argues that overall system costs are lower in a centrally planned system, meaning a larger connected transmission grid. Notably, this study also concludes that storage has only a limited role as part of the optimal transmission system, even at high shares of renewable energy penetration. This shows that grid extension is highly favourable over storage capacity. Brouwer et al. (2016) simulated several scenarios of renewable energy integration, they also concluded that power storage is too expensive and extra interconnectors were valuable from an RES integration scenario of about 60%. However, some researchers contradict the notion that grid extension is always a financially more attractive than storage. The impact of renewable energy integration and medium and long-term storage on the electricity system and its financial effects were modelled by Bussar et al. (2014), using planning tool GENESYS. Contrary to others (Van Staveren, 2014; De Pater, 2016; Jägemann et al., 2013) they find that long-term storage is essential for fully renewable systems. Their results show an optimal system in terms of RES-E integration, storage and the overlay grid, with about 20% of annuity cost allocated to storage systems.

Despite numerous models and extensive research being published about optimising the energy market, not many are quite as comprehensive as the research conducted by Gils et al. (2017).

Their linear cost optimisation model integrates backup capacity, storage, transmission and curtailment, optimised over a time-series from the present to 2050, varying RES-E scenarios from 20 to 100% integration. A significant element in this study that was not yet found in other works, is the modelling of Concentrated Solar Power plants as a dispatchable backup option. Using the REMix tool they quantify and optimise grid, storage and dispatchable generation capacities and find that curtailment stays below 20% in high RES integration scenarios.

This field is extensively researched, with regard to transmission, storage and integration of renewable energy. The majority of the works considered, do not include carbon capture and storage, nor do they restrict carbon emissions to Paris agreement levels. A fully renewable Europe, as discussed in Rodriguez et al. (2014), would require significant storage or transmission capacity. Since these capacity requirements are accompanied by significant cost, carbon capture and storage could play a significant role that is now ignored: it makes generation of electricity independent from weather conditions possible, without emitting CO_2. Its role was carefully researched in Brouwer et al. (2016), under high renewable energy penetration scenarios of 80%. Brouwer et al. (2016) foresees a role for CCS in the future energy system. However, the 80% RES obligation pales in comparison to the Paris agreement restriction. The effect of carbon capture storage on near 0 emission electricity systems remains subject to uncertainty. The role of carbon capture storage and its socio-economic impacts on electricity generation in the future is explored by Koelbl et al. (2015). They find that the use of CCS raises the gross added value and lowers import dependency. However, their results are found using an import output model (see figure 2.3). These types of studies have a different focus and yield different results. This study shows a promising sign for the role that CCS could play in the future energy system.

All of the above-mentioned studies provide valuable information on the integration of renewable energy in the electricity system, but two main research gaps remain: the modelling of near 0 emission energy systems and the implementation of CCS in those systems. In most relevant research, integration of renewable energy is modelled as a required percentage of renewable energy (up to 80%) (Brouwer et al., 2016; Huber et al., 2014; Weitemeyer et al., 2015; De Pater, 2016). While this is a step in the good direction, the Paris agreement calls for more rigorous measures. There is not much known about the effects of a near-zero or even negative carbon intensity energy system, required in future energy systems. Some studies did model stricter CO_2 mitigation requirements (Rodriguez et al., 2014; Steinke et al., 2013), the consequence of this restriction is threefold: large generation capacity installation, large interconnections through transmission lines and large storage capacities.The role of carbon capture and storage is not taken into account in these studies. The conclusions of modelling a fully renewable energy system could significantly change when the option of CCS is taken into account.

Table 2.2: *This table provides an overview of the critical data from the aricles discussed, providing the reader with a clear picture without having to read all the underlying literature. GAMS = General Algebraic Modeling System, CPLEX = optimization software package, URBS-EU = a linear optimisation model, ENTSO-E = European Network of Transmission System Operators for Electricity, EUNA = European Union North Africa, GENESYS = Optimisation model, CMA-ES HSM = dynamic optimisation model, EUMENA = European Union, Middle East, North Africa, PLEXOS = linear optimisation model*

ID	Reference	Scenario	Methodology	Time-scale	Region
1	Spiecker and Weber 2014	Different paths until 2050	Stochastic optimization: E2M2s model GAMS model CPLEX as solver	Hourly load profile	EU region
2	Huber et al. 2014	10, 30, 50, 70% PV, onshore wind penetration (50% in 2030)	Power ramps or gradients occurring over different time horizons	Hourly load profiles	EU region
3	Rodriguez et al. 2014	100% renewable energy	Linear optimization model	Hourly, 8 years from 2000 - 2007	30 European Countries
4	Schaber et al. 2012a	Expected Renewable energy generation capacities for 2020	URBS-EU Linear Optimization using GAMS	Hourly, 6 representative weeks over different seasons	EU 83 regions, 50 correspond to ENTSO-E, 33 offshore regions
5	Jägemann et al. 2013	80% Renewable energy / 80% emission reduction in 2050	Dynamic linear optimization	Hourly	EUNA region
6	Schaber et al. 2012b	Renewable energy capacity for 2020	URBS-EU LP min total system costs	Hourly load profile	Grid integration cost¡ 6/MWh
7	Bussar et al. 2014	100% renewable energy generation	GENESYS Linear optimization CMA-ES HSM	Hourly load profile 3 year simulation	EUMENA region
8	Weitemeyer et al. 2015	100% renewable energy	Dynamic optimization	Hourly load profile 2000 - 2007	Germany
9	Schmid and Knopf 2015	2010-2050	LIMES-EU+ Linear optimization	hourly load profile	EUMENA region

ID	Reference	Scenario	Methodology	Time-scale	Region
10	Steinke et al. 2013	100% renewable energy generation	Linear optimization GAMS/CPLEX	Hourly load profile 8 years	Western Europe
11	Brouwer et al. 2016	40%, 60%, 80% renewable energy to 2050	PLEXOS: Linear optimization and unit commitment	Hourly load profile	Western Europe in regions
12	Gils et al. 2017	20 to 100% renewable energy	REMix-EnDAT REMix-OptiMo GAMS	Hourly load profile 2050	EUMENA region
13	Haller et al. 2012	90% emission reduction in 2050	LIMES Linear optimization GAMS/CPLEX	Hourly load profile	EUMENA region
14	De Pater 2016	40%, 60%, 80% renewable energy to 2050	Linear optimization, using MATLAB	Hourly load profile	EU region
15	Van Staveren 2014	CO_2 costs as parameter in model	Clustered Unit commitment GAMS	Hourly load profile	EU region
16	Verzijlbergh et al. 2014	Expected RES 2025, and + 50% scenario	Unit commitment cost optimization	Hourly load profile , 8 years	Conceptional 2 node / EU-region

2.5 Relevance to Industrial Ecology

This research relates to Industrial Ecology in two distinct ways. It contributes to its core values of through addressing the issues of sustainability, and by taking a systems approach its methodology is closely related to the methodological approach that is inherently important in Industrial Ecology.

The field of Industrial Ecology is founded upon the ideas that human impact on the Earth?s resources should be limited. Over the years it has evolved into a field that studies how to approach and maintain sustainability under constantly changing circumstances in technology, the economy and society (Graedel and Allenby, 2010). This research seeks to address the issue of sustainability by contributing to the sustainable energy transition. This research will provide valuable insight that might help to overcome the barriers that prevent a transition towards a sustainable electricity system. Hence, the objective that this research addresses corresponds to the general aim of Industrial Ecology. According to Graedel and Allenby (2010), an industrial system cannot be viewed in isolation, since it is inseparably connected to the surrounding system that it is embedded in. The industrial system influences the state of its environment and vice versa. This is more commonly referred to as system nestedness. Hence, studying such a system requires a systems view, incorporating both the object of study and its environment. The electricity system is of complex nature, planning and optimisation problems relating to this electricity system classify as 'wicked problems' (Rittel and Webber, 1973). According to Dave et al. (2011) solving with wicked problems require a systems approach. This systems view provides the basis of the optimisation model that is proposed in the methodology section of this research, as would an Industrial Ecologist do.

In conclusion, this research aims to study an issue that follows the general aim of industrial ecology, using an industrial Ecologists systems approach, demarcated only by the timeframe and scope of this research. It is, therefore, a valuable addition to the field of Industrial Ecology.

Model Description

The research questions require a modelling approach as a representation of the power system. This section elaborates on the methods used to design a model that was appropriate to answer the questions. Section 3.1 elaborates on the model design, the extension and an explanation of the unit commitment model that was used. Section 3.2 highlights the model assumptions that has the largest implications. Section 3.4 describes the evaluation of input data. To conclude, section 3.5 provides a description of the steps undertaken to verify the functioning of the model.

3.1 Model Design

This section discusses how the essential parts of a future energy system are modelled. Following the theoretical background and the research questions, the essential parts that are to be implemented when modelling the electricity system are:

1. Conventional Generation;
2. Renewable Energy Generation;
3. Storage;
4. Transmission;
5. Emission cap: COP21 agreement;
6. Technical limitations to conventional generation.

The first four steps are covered in section 3.1.1, the fifth step is covered in section 3.1.2, the sixth step is covered in section 3.1.3.

3.1.1 Modelling The Essentials

The need for storage and transmission in a future energy system is extensively analysed in earlier work by De Pater (2016). The main part of the model that is created for this research is based on his work. Eventually, this model will be reprogrammed in Python, will include new constraints and will be used for other research purposes. Hence, it requires a new name. Within this thesis, the Python reprogrammed model is referred to as the model **I-E-Energy**.

Modelling of conventional Generation
Costs for conventional generation can be roughly divided into three main categories: capital expenditures, fixed operation and maintenance costs and variable operation and maintenance costs. Variable operation and maintenance costs can be modelled linearly (the unit is MWh of electricity produced with an hourly resolution). Linear modelling of capital expenditures and fixed operation and maintenance costs is less straightforward: the installation of a new power plant requires capital costs, which are spent once for every power plant, during its lifetime. Fixed operation and maintenance costs are spent throughout the year but are usually accounted for once every year. Yearly costs and lifetime costs are characteristics of mixed integer programming, including either binary variables (installation or not), or integer variables (i.e. one can construct 1 or 2, but not 1.5 powerplants). In order to create a model that is linear, a time-cost factor is introduced. The capital expenditures are divided by the lifetime and by the hours of the year and multiplied by the hours of the run, the fixed operation and maintenance costs are divided by the hours of the year and multiplied by the hours of the run. This way, the fixed costs become linear. Appendix A gives an overview of the associated equations.

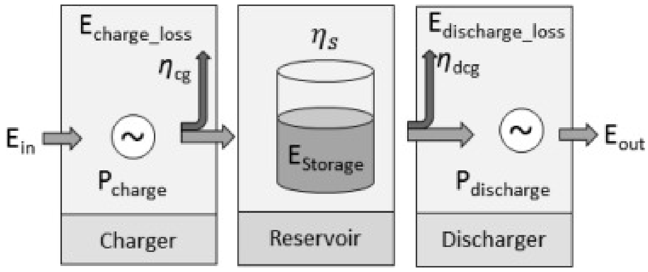

Figure 3.1: *The parts representing a storage unit, reprinted from Bussar et al. (2016). The figure shows how the the charger, the discharger and the reservoir make up a storage unit. When the energy is stored, the charger translates power (E_in) to stored energy $E_Storage$. This process has efficiency η_{cg}. The capacity of the charger is P_Charge (kW). The energy is stored in the reservoir, which has storage efficiency η_s. When power is fed into the grid, the discharger turns on. The discharger converts the stored energy back to electricity with efficiency η_{dcg}, after which it is fed back into the grid (E_out)*

Renewable Energy Generation
Renewable energy generation functions similarly to conventional generation. The same costs apply (Capex, fixed O&M, variable O&M). However, there is are two large differences. First, renewable energy from the wind and sun do not require fuel costs. Secondly, the downside of renewable energy is that there is no control over when the sun shines or when the wind blows. The variable power output of renewable energy sources is modelled using capacity factors that represent the hourly availability of renewable energy within a country. The capital costs and fixed O&M costs remain, which means that the same time-cost factor that is explained in section 3.1.1 applies. Appendix A gives an overview of the associated equations.

Storage Units
The storage unit is modelled somewhat differently because there are some more complicated parts involved. Storage units have a charger and discharger, which converts the stored energy to usable energy (electricity). This part functions similar to a generator, in the sense that it can deliver power at a certain time and has a certain capacity. The consecutive time that it can deliver power is dependent upon the size of the reservoir that it draws potential energy from. This reservoir (e.g. a lake or a battery) is filled with a finite amount of energy (MWh). This system is explained in figure 3.1. Appendix A gives an overview of the associated equations.

Modelling of Transmission
To be able to model a high temporal resolution, the number of nodes in the system needed to be reduced. Reducing the number of nodes in the electricity system constitutes to simplifying the transmission system. This is achieved through implementation of a zonal grid. In a zonal grid, a predefined region (that can be a municipality, country or continent) operates as one node: generating power, transporting and storing it, to fulfil its demand. The demand is an aggregate of the total demand in the zone. Power flows freely in that zone (e.g. If the Netherlands act as a node (zonal grid), then Amsterdam and Rotterdam instantly receive their energy at the moment that node Netherlands receive it. The demand of the Netherlands is equal to the aggregated demand of Amsterdam, Rotterdam and the rest of the country).

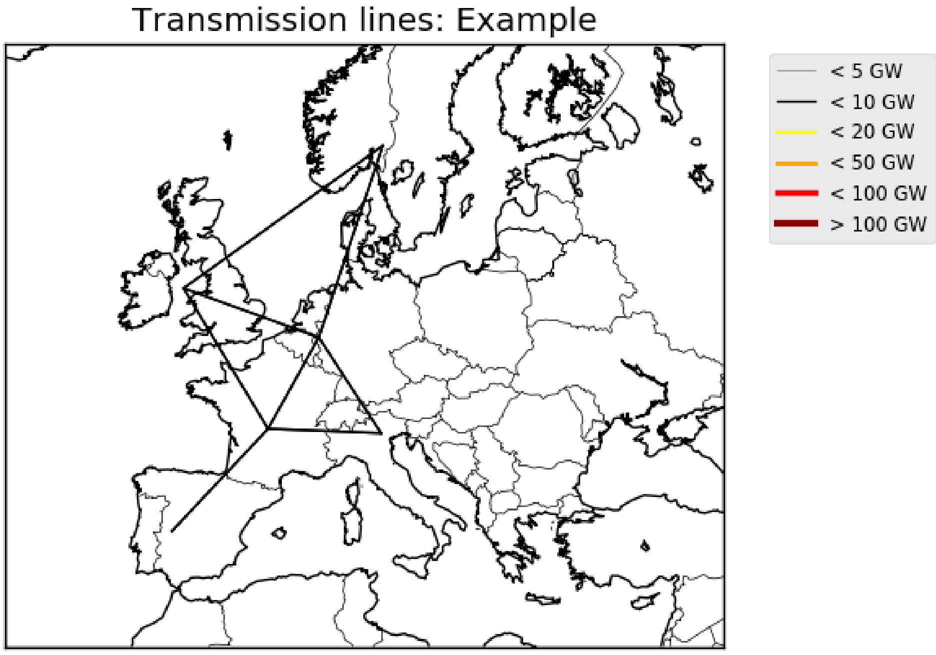

Figure 3.2: *Exmple of a linearised inter-regional transmission grid for Europe, modelled using Python. Transmission capacity is represented in GW, lines represent the linearised power flow from region to region.*

Secondly, the transmission lines are built from several main components: cables, poles and substations. Costs for all three do not increase congruently to transmission line length extensions. Modelling these components accordingly turns the optimisation problem into a mixed integer problem. The other simplification is the linearisation of this problem. The simplified approximation of flows between regions respects the conservation of current (Kirchhoff's first law) but ignores the voltage laws (Kirchhoff's second law). This simplification was modelled as such in De Pater (2016) and in Schaber et al. (2012a). The resulting parameters for modelling are transmission losses dependent on the length of the cable and (linear) investment costs for line capacity. The linear optimisation model for transmission lines is more commonly known as a transportation problem, further elaborated in Conejo et al. (2006). In short, it represents minimisation of system costs for transporting n units to m destinations. The mathematical representation of the transmission line model can be found in A. An example of an inter-regional transmission grid is given in figure 3.2.

3.1.2 Implementing the Emission Cap: COP21 constraint

Most researches mention scenarios and pathways consistent with a certain amount of CO_2 emission in 2050, or a cumulative maximum CO_2 emission that has a certain probability of staying the 2 °C barrier. In section 1.1, the figure found most useful for this research (considering the variation in countries) is a certain amount of CO_2 emitted per MWh electricity supplied to the consumer. The CO_2 constraint that is modelled serves the purpose of restricting the carbon intensity of generation to the desired amount, consistent with a scenario estimate that has a certain probability of remaining within the 2 °C barrier, in g CO_2 / kWh electricity supplied. As such, for the model to stay linear, the constraint is implemented as follows:

$$\sum_{i \in G} \sum_{n \in N} \sum_{t \in T} \varsigma_i * P_{i,n,t} \leq COP_{max} * P_D \;\; \forall i \in G \;\; \forall n \in N \;\; \forall t \in T \tag{3.1}$$

Table 3.1 provides an explanation of the symbols used in the constraint mentioned in equation 3.1.

Symbol	Explanation	Notation
G	Set of Generation technologies	i
N	Set of Nodes (which can be countries or regions)	n
T	Set of timesteps representing a full year (hours)	t
$P_{i,n,t}$	Power generated by generator i, in node n at time i	MWh
ς_i	Carbon intensity of Generation	tCO_2/MWh
COP_{max}	Maximum allowed Carbon intensity	tCO_2/MWh
P_D	Total Electricity Demand	MWh

Table 3.1: *Explanation of mathematical symbols of Equation 3.1, representing the maximum carbon intensity of generation consistent with a 2 °temperature rise in 2100*

3.1.3 Powerfys model: Analysing technical Constraints

To gain insight into the consequences of ignoring technical constraints, a second model is required. To this extent, the model POWERFYS is used. Powerfys is a model developed internally at ECOFYS Netherlands B.V. This model classifies as a unit commitment model. It offers a wide range of possible technical constraints such as ramping, on/off times, startup or shutdown costs, that can be added or ignored as the user wishes. Furthermore, it provides the opportunity minimising costs for two energy markets: the day ahead auction and the intra-day auction. The day ahead market, bids are submitted every day for the day to come at 12 AM. However, the hour to hour variations in renewable energy production and demand fluctuations prevent the power market from making 100% accurate predictions (”perfect foresight”). Any inaccuracies that develop between submission of day ahead bids and real-time production are traded within the intraday market. Powerfys models these markets through a rolling planning. The use of this rollin g planning in this research is considered out of scope. Realising that this difference exists however, is important, as ignoring it leads to overestimation of the reliability of renewable energy sources.

The overall aim of the Powerfys model is to provide a detailed and very precise estimate of the day by day dispatch of a set of predefined (aggregated or single) generation units. The mathematical formulation of the model is loosely based on Abrell and Kunz (2015). However, in the course of its lifetime, it has been subjected to several changes, the details of which are confidential. The characteristics of the model that are relevant to this research are summarised in table 3.2.

I-E-Energy is both useful to determine the installed capacity and the levelised costs of electricity on a national level; it ignores technical constraints. Powerfys incorporates technical constraints but is not able to determine installed capacities. The two models are complementary to one another in two ways:

1. The installed capacity found by I-E-Energy provides the input parameters for Powerfys.
2. The operational costs found by I-E-Energy can be verified using the Powerfys model.

As such, the two models together provide an accurate prediction of the current and future electricity system. Table 3.2 gives an overview of the characteristics and possibilities of both models.

Characteristics	I-E-Energy	Powerfys
Model type	Linear	Unit commitment
Aim	Minimize system Cost	Minimize system Cost
largest continued time-series	one year	36 hours
Resolution	Hourly	Hourly
Constraints		
CO_2 cap	Yes	No
RES requirement	Yes	Yes
Ramping	No	Yes
On/off-time	No	Yes
Startup/shutdown costs	No	Yes
Mustrun	No	Yes
Curtailment	Yes	Yes

Table 3.2: *Characteristics of I-E-Energy, (left) and Powerfys model (right), representing the most important characteristics of both models, their similarities and their differences.*

For this research, not all of the functionality offered by Powerfys is utilised. The scope of this research does not include an assessment of a rolling planning, but rather focuses on the technical limits of conventional power plants. A mustrun constraint is also disregarded. The remaining constraints are taken into account. Ramping refers to the rate at which a (conventional) power plant can change its load. As the demand for electricity changes every hour, every quarter and every minute, power plants need to be able to adjust accordingly. Not all technology is able to change pace that quickly. Ramping rates are usually expressed in Megawatt per minute, referring to the capacity adjustment that a unit is capable of making within a minute. Startup and Shutdown costs refer to the costs associated with starting up or shutting down of a power plant. On and off-time refers to the minimum amount of time that a unit needs to be on, or off in order function properly.
The origin of such a constraint could be financial (e.g. the startup costs are higher than the return if a unit is switched on for one hour), but could also reflect a physical barrier (e.g. a certain amount of time is required to synchronise a power plant with the grid it is connected to) (Van den Bergh and Delarue, 2015). Either way, these constraints affect the flexibility of power generation units.

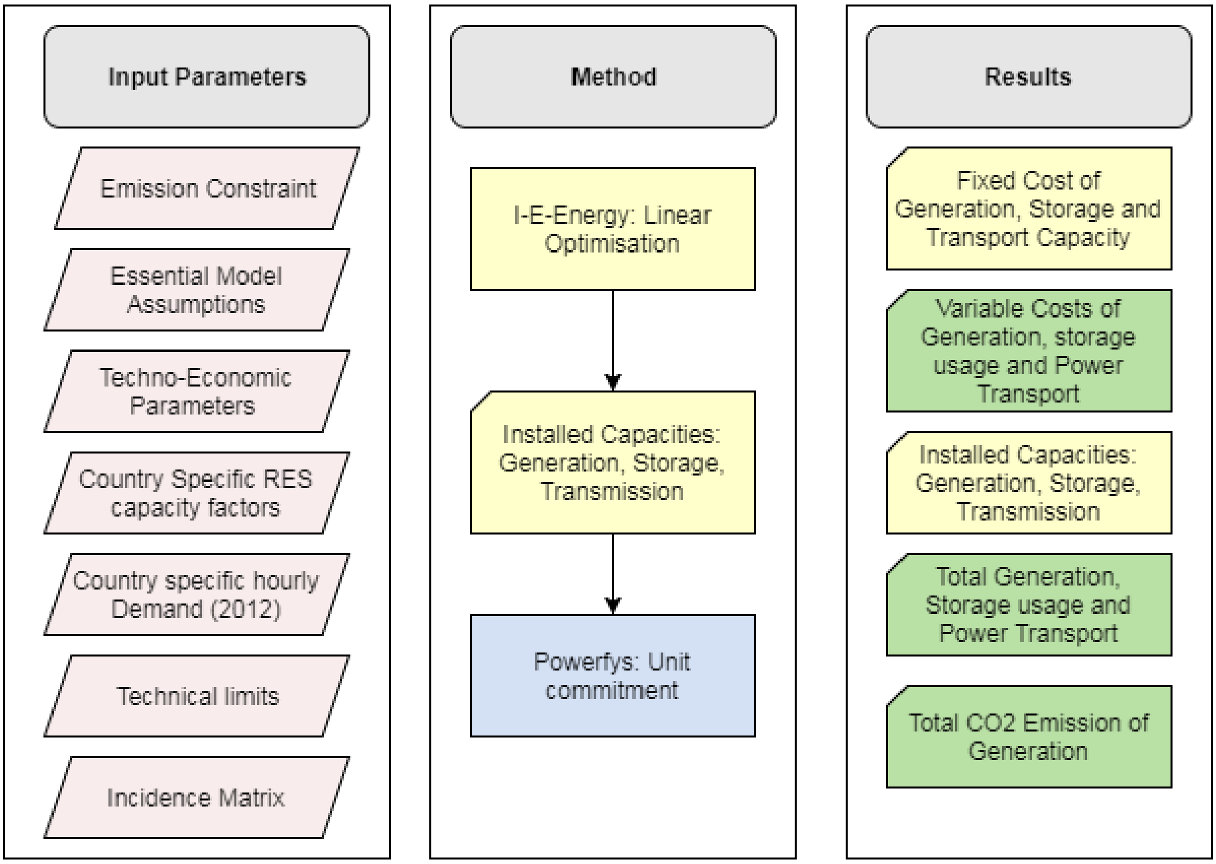

Figure 3.3: *This flowchart describes the relation between input data, the modelling steps and the desired results. Input data is illustrated by red parallelograms, the results generated by only model I-E-Energy are illustrated by yellow cards, the results generated by both models are represented by green cards. The yellow and blue rectangles represent the models I-E-Energy and Powerfys, respectively*

3.2 Model Assumptions with Large Implications

Achieving the emission reduction targets that are set by the COP21 agreement, will significantly impact the development of the Power sector in Europe. These developments are taken into account as model assumptions. Four assumptions are influential to the model outcome to such an extent that they need to be explicitly mentioned:

All cost parameters are projections for 2050. The CO_2 emission reduction targets established by the members of the Paris agreement, consider pathways for a future energy system design. As such, the parameters considered in that power system design and their relative differences should resemble the cost of electricity in 2050 as much as possible. Therefore, all costs parameters considered are projections for 2050. However, projecting costs for such lengthy periods (over 30 years) will increase the margin of error. The extend to which these parameters are influential is further analysed in the sensitivity analysis, provided in chapter 6.

Demand rises with 40% in 2050. In terms of demand growth, technology evolution will affect the electricity system both positively and negatively. Energy efficiency improvements may reduce the need for electricity. However, in order to achieve emission reduction targets, other sectors will shift towards electricity usage, which increases demand. Electrification of the transport system will exchange current energy carriers for electricity. While electric cars can act as a storage unit, the total electricity demand is expected to increase, due to electric cars. Meanwhile, the shift from natural gas use for space heating towards other technologies, such as heat pumps, puts additional pressure on electricity demand. According to Roadmap (2010), the net effect of fuel shift and the phase-out of natural gas will be a 40% increase in demand. As such, this number is implemented as a model assumption.

Carbon capture and storage technology is available on a large scale in 2050. The Dutch 2017 coalition agreement mentions capture and storage of 18 megatonnes of CO_2 in 2040. However, the large breakthrough in commercially viable carbon capture and storage technologies in the Netherlands has yet to commence. For this model, the ambition of the Dutch government is taken seriously; carbon capture and storage is considered as a viable option in 2050. According to Schröder et al. (2013) and Gough and Upham (2011), the technologies should be available between 2020 and 2030, with gradually decreasing investment costs from then on, due to technology improvement.

European wide integration of the Power system. Intensive collaboration between the members of the European continent is beneficial to a future energy system with high shares of renewable energy. Earlier research (De Pater, 2016) proved the importance of European integration of the power grid, which can significantly reduce the cost of electricity and the need for storage while keeping GHG emissions to a minimum. The assumption is made that in 2050, a transmission grid is available for all neighbouring countries or regions within the European Union.

3.3 Defining the Input Data

The model, described in chapter section 3.1 requires a set of input data, based on which it can find an optimal solution. This section covers the definition of the (fixed) parameters. There are six main categories of data associated with I-E-Energy and Powerfys:

- Techno-economic parameters I-E-Energy;
- Techno-economic parameters Powerfys;
- Demand data;
- Renewable energy production data;
- Technical Constraints;
- Emission Data.

3.3.1 Techno-Economic Parameters I-E-Energy

The main purpose of the model is to minimise system costs, subject to a series of constraints. These system costs are a defined as the sum of fixed costs (FC) and variable costs (VC). Subsequently, the variable costs can be divided into fixed operation and maintenance costs (FOM), and the costs of variable generation (VOM). Capital expenditures (Capex) are only spent once in the lifetime of the technology. Fixed operation and maintenance costs remain constant throughout the year. In large volumes, variable operation and maintenance costs converge to fuel costs (Mercure and Salas, 2013). As was presented in section A.2, the capital expenditures and fixed operation and maintenance costs are incorporated in the time-cost factor alpha and beta.

For generation technologies, the costs considered are capital expenditures and operation and maintenance costs (fixed and variable). Since renewable energy sources do not require any fuel costs, their costs are assumed to be almost zero. Most literature on which this research is based, model these costs as zero. However, in this research, a tiny amount of variable costs was modelled, which prevents the model from generating renewable electricity and simultaneously getting rid of it using transmission efficiency losses (a consequence of the modelling setup). Technically, there are some variable costs associated with renewable energy production: at higher wind speeds, there is more corrosion. Most parameters are based on De Pater (2016), Bertsch et al. (2012), Brouwer et al. (2016), Jägemann et al. (2013) and Rodriguez et al. (2014).

Transmission is incorporated in the model as a water-flow model, meaning that only costs and efficiency are relevant. This approach was chosen by De Pater (2016), on which this model is based. Since transmission lines are considered a mature technology.

Carbon capture and storage is implemented as a supplementary technology to the current thermal power plants. CCS is applied differently, depending on the type of fuel that is processed. Therefore, costs additional costs per technology differ. The emission factor of the technology for coal and gas is less positive. The emission factor of biomass combined with CCS turns negative. IEAGHG (2011a) gives an overview of investment costs for generation technologies with and without CCS. These investments, unfortunately, differ from the costs assumed for this research. Also, separate requirements regarding co-firing of biomass for coal are required. Implementing these costs would complicate the optimisation problem, so the choice is made to somewhat simplify the approach. IEAGHG (2011a) also provides the costs for coal CCS, CCGT CCS and biomass CCS separately (both Capex and fixed operational costs). CO_2 emission factors for coal CCS and biomass CCS are averaged from Bertsch et al. (2012) and Fürsch et al. (2013). CO_2 emission factors for biomass CCS are averaged from IEAGHG (2011a) and Sanchez et al. (2015).

This research focuses on the future energy system, mainly at 2050 projections. The techno-economic parameters are represented in table 3.3. The sources of these costs are all represented in appendix B.5. All these costs are future projections, based on assumptions. This means that the margin for error could be substantial. The extend to which these costs influence the model outcome, is presented in chapter 6, section 6.2. Important to note that the cost parameters were obtained with the emphasis on the relative price of the technologies, since this research focuses more on the ratio between the technologies rather than on absolute numbers.
Conventional electricity generating entities such as Coal and Gas power plants produce a certain amount of CO_2 emissions. To abide by the levels of CO_2 emission congruent with a 2°C scenario, these emissions should be incorporated in the model.

Generation Technology	CAPEX (€/kW)	FOM (€/kW/yr)	VOM (€/kWh)	Lifetime (yr)	η	CO_2 tCO_2/MWh
PV	928	21	0.001	25	1	0
Wind	1091	49	0.001	25	1	0
Coal	1600	28	37.5	42.5	0.47	0.48
Gas CCGT	800	20	66.7	30	0.6	0.28
Biomass	2640	90	84.5	33	0.35	0.035
Coal CCS	1985	51	37.5	42.5	0.47	0.05
Gas CCGT CCS	1222	51	66.7	30	0.6	0.102
Biomass CCS	3025	119	143.5	33	0.35	-1.44
Transmission	1 (/kWkm)	0	0	40	0.96	0

Table 3.3: *This table shows the techno-economic parameters of Generation technologies for 2050. It shows capital expenditures (CAPEX), fixed operation and maintenance costs (FOM), variable operation and maintenance costs (VOM), the lifetime of the technology and its generation efficiency. A further elaboration on the figures in this table can be found in appendix B.5.*

Storage
Storage parameters have similar parameters as generation technologies, with one important difference: apart from a conversion capacity, which is analogous to the installed capacity of generation technologies, they have an energy capacity (storage capacity). There is a maximum storage volume that the unit has. This volume corresponds to the maximum amount of energy (MWh) that the storage can save. At maximum storage capacity, a battery would be fully loaded, a lake storage would be full: any water (that is potential energy) poured into the lake would result in flooding of the surrounded areas. The storage conversion - and storage capacity parameters are summarised in table 3.4. An overview of the specific figures per literary source can be found in appendix B.5.

Storage Technology	CAPEX conv (€/kW)	CAPEX storage (€/kW)	FOM (€/kW /yr)	VOM (€/kWh /yr)	Lifetime (yr)	η (%)
Battery Storage	222	227	29.25	0	15	0.95
Hydro pumped	623	46	27.3	0	53	0.91
H2	867	20	40	0	32.5	0.59

Table 3.4: *Cost parameters for storage units in 2050. It shows the capital expenditures of the conversion unit (CAPEX conv), the capital expenditures of the storage reservoir (CAPEX storage), fixed operation and maintenance costs (FOM), efficiency of storage conversion and the lifetime. Figures are averages based on Bussar et al. (2016); Steinke et al. (2013); Zakeri and Syri (2015), which can be found in appendix D.*

3.3.2 Techno-economic parameters Powerfys

The functioning of Powerfys was explained in section 3.1.3 a follow-up run was performed using Powerfys. Powerfys is capable of optimisation under technical constraints, turning the optimisation problem into a mixed-integer unit commitment problem. Section 3.1.3 provided an overview and an explanation of the technical constraints taken into account. The input parameters of Powerfys are presented in table 3.5.

Technology	η	Min Gen	On time	Off time	Start up c.	Shut down c.	Ramp (Up)	Ramp (down)
Unit		MW/ MW	hr	hr	€/ MWh	€/ MWh	MW/ min	MW/ min
Coal	0.47	0.40	6.00	(-)	56.00	(-)	0.04	0.05
Coal Agg	0.47	0.10	(-)	(-)	56.00	(-)	0.04	0.05
Coal CCS	0.47	0.40	6.00	(-)	56.00	(-)	0.04	0.05
Coal CCS Agg	0.47	0.10	(-)	(-)	56.00	(-)	0.04	0.05
Gas CCGT	0.60	0.33	2.00	(-)	25.00	(-)	0.04	0.07
Gas CCGT Agg	0.60	0.08	(-)	(-)	25.00	(-)	0.04	0.07
Gas CCGT CCS	0.60	0.33	2.00	(-)	25.00	(-)	0.04	0.07
Gas CCGT CCS Agg	0.60	0.08	(-)	(-)	25.00	(-)	0.04	0.07
Biomass	0.35	0.20	(-)	(-)	(-)	(-)	0.13	0.13
Biomass Agg	0.35	0.05	(-)	(-)	(-)	(-)	1.00	1.00
Biomass CCS	0.35	0.20	(-)	(-)	(-)	(-)	0.13	0.13
Biomass CCS Agg	0.35	0.05	(-)	(-)	(-)	(-)	1.00	1.00
PHS	0.81	(-)	(-)	(-)	(-)	(-)	1.00	1.00
H2	0.38	(-)	(-)	(-)	(-)	(-)	1.00	1.00

Table 3.5: *Technical Parameters Powerfys, showing the technical parameters per generation technology. η= Efficiency, Min Gen = Minimum Generation (as a percentage of generation capacity), On time/off time = the minimum time that a generator needs to be turned on/off, start up costs = costs associated with startup and shutdown of a generator, rap rate = the speed at which a generator can adjust load as a percentage of generation capacity. Data provided by Hentschel et al. (2016).*

The ideal modelling situation would entail a real world representation of all Power plants in Europe. This would create hundreds of units for which Powerfys needs to run. Unfortunately, Powerfys is subjected to computational limits as well. Therefore, the Powerfys units are divided into normal and aggregated units. The normal units operate as a conventional power plant, with startup costs, minimum electricity generation and minimum on-times. The aggregated units however, represent the sum of all left over capacity after a division into smaller units was simulated. The precise division of the model runs that were performed in this research, are further elaborated on in section 4.3. The aggregated units have lower minimum generation time since they are representations of several smaller power plants, which are able to deliver power with more flexibility compared to a single plant. The aggregated units are assumed to have only 25% of minimum generation of their conventional counterparts. For the same reason, they do not have minimum generation.

3.3.3 Demand Data

The demand data used for this study is taken from the European network of Transmission system operators, or ENTSO-E. This institution provides hourly demand data for all countries in the European Union and encompasses Norway and Sweden as well. The data is publicly available until 2014 at the moment of writing. Typical electricity demand is subjected to seasonal patterns, weekly patterns and daily patterns. The seasonal pattern is clearly seen in figure 3.4 a. It starts in the winter, where electricity demand is high. During summer it gets warmer, the days are longer and electricity demand decreases. From figure 3.4 b, both weekly and daily patterns can be seen. Saturday and Sunday have lower peaks, then the weekdays have higher peaks. The daily pattern can be distinguished as well: a small peak in the morning, then a period of lower demand during the day, followed by a higher peak in the evening.

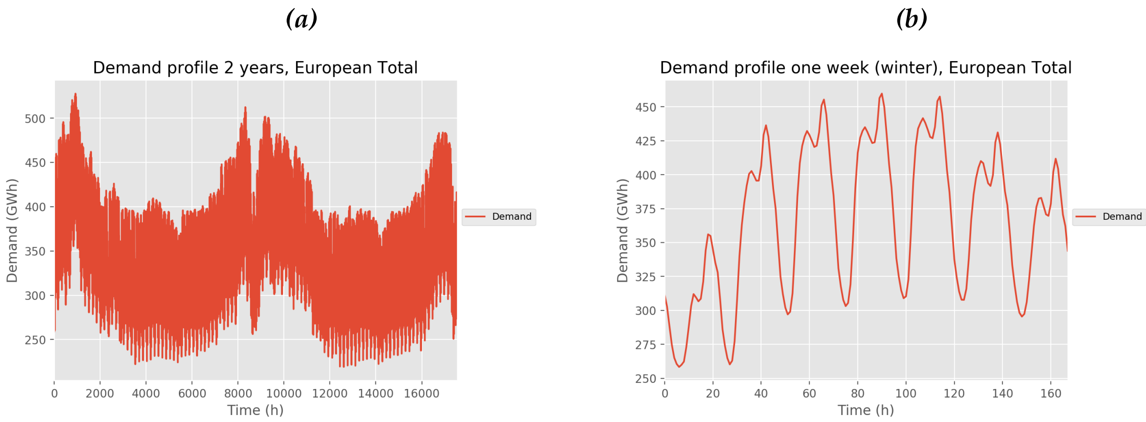

Figure 3.4: *Demand profile, EU average, for a full two years (left) and a demand profile of the first week of January (right) (ENTSO-E, 2015). The figures show seasonal and daily variations in hourly demand in TWh*

Table 3.6 shows the total yearly demand per country. Variations can partly be attributed to population size. However, the per capita electricity consumption is higher for most countries in Western Europe, compared to Eastern Europe (e.g. the Netherlands has a higher energy consumption than Romania, while Romania has a larger population).

Country	**2012 (TWh)**	**2013 (TWh)**	**Country**	**2012 (TWh)**	**2013 (TWh)**
Austria	69	69.5	Hungary	38.8	39.1
Belgium	84.4	86.3	Ireland	25.5	25.9
Bulgaria	36.6 =	36	Italy	323.9	316.3
Switzerland	47.2	47	Lithuania	10.5	10.6
Czech Republic	62.6	62.9	Luxembourg	6.3	6
Germany	468.8	463.7	Latvia	7.1	7.3
Denmark	34	31.9	The Netherlands	107.5	114
Estonia	8.1	7.9	Norway	128	128.3
Spain	251.6	246.6	Poland	145.5	146.6
Finland	85	84.2	Portugal	48.9	49.1
France	488	492.6	Romania	53.7	50.7
United Kingdom	308.2	305.8	Sweden	141.7	139.7
Greece	50.2	46.5	Slovakia	28.1	27.9
Croatia	17.3	17.1	Slovenia	12.7	12.8

Table 3.6: *Total Electricity demand per country for the year 2012 and 2013 (ENTSO-E, 2015)*

3.3.4 Renewable energy production data

Modelling the variable character of renewable energy always proves to be a challenge. Utilisation of complicated weather models to convert weather data to electricity production is out of the scope of this article. Fortunately, a comprehensive set of this kind of data is provided by Pfenninger and Staffell. The data-set contains 37 years of hourly capacity factors for intermittent renewable energy in 28 countries of the European Union, including Switzerland and Norway. The data ranges from 1980 until 2016. Capacity factors for wind energy are given for both onshore and offshore wind power. Both are aggregated per country which gives the final capacity factor that is used in this research. The PV capacity factors pro vie two data files. Based on different model types, they provide MERRA-2 and CM-SAF SARAH simulations. MERRA-2 provides the most complete data-set and is therefore used in this research. Both wind and PV capacity factors do not include summer time/daylight savings time. This set of data provided the required input data to model the hourly profile that both solar PV and wind power follows, for all countries in Europe (In section A.2, this is defined as a constraint that has to be satisfied on an hourly basis). Figure 3.5 shows the patterns of both wind and solar energy capacity factors. For both energy types, there is a seasonal pattern. figure 3.5 a and b show that solar PV production pattern peak in summer, while wind production peaks in summer. Solar PV has a clear daily pattern, for wind not so much (figure 3.5 a, b).

The capacity factors for wind are calculated for each country individually. The set of data distinguishes between onshore and offshore wind. This is important to note, because wind at sea generally generates more electricity and therefore inhibits a higher capacity factor. Offshore and onshore capacity factors are calculated in a similar manner: the total installed capacity per country on land is divided by the total hourly production of electricity from turbines on land. The total installed capacity per country on sea is divided by the total hourly production of electricity from turbines on sea. The hourly capacity factor per country is a weighted average of these two factors based upon the installed capacity in that country: if 10% of the installed capacity is on sea and 90% of the capacity is on land, the weighted average is distributed accordingly. The total fleet of current installed wind power capacity is 91% on land and 0.09 % at sea.

3.3.5 Technical Limit to Pumped Hydro storage

One limitation that significantly impacts the optimisation problem is the technical potential of pumped hydro storage. This potential closely relates to the presence of altitude differentials in specific countries. For example, the Netherlands does not have the possibility of pumping up water to altitudes high enough to viably install a pumped hydro storage system, whereas the French Alps offer plenty of possibilities. Simultaneously, limiting the modelling capacity for pumped hydro to its countries technical potential does not increase computation time. Gimeno-Gutiérrez and Lacal-Arántegui (2013) provide a comprehensive report on the technical potential for pumped hydro storage per country in the European Union, in four scenarios. Table 3.7 provides an overview of the average of those four scenarios, for each country individually.

3.4 Data Evaluation

This section focuses on validation of the data used and focuses on the demand profiles, the capacity factors for both wind and solar energy production and CO_2 emission data.

3.4.1 Evaluation of Demand Profiles

The Demand profiles are actual electricity consumption profiles from ENTSO-E (2015). The hourly data provides the real consumption data for the year 2012. Hourly electricity consumption for a region can be easily constructed without losing the hourly variation. However, night and day time differences between countries can widen the peaks and valleys. If for example the hourly profiles of Norway and Portugal would be aggregated, the timezone difference would

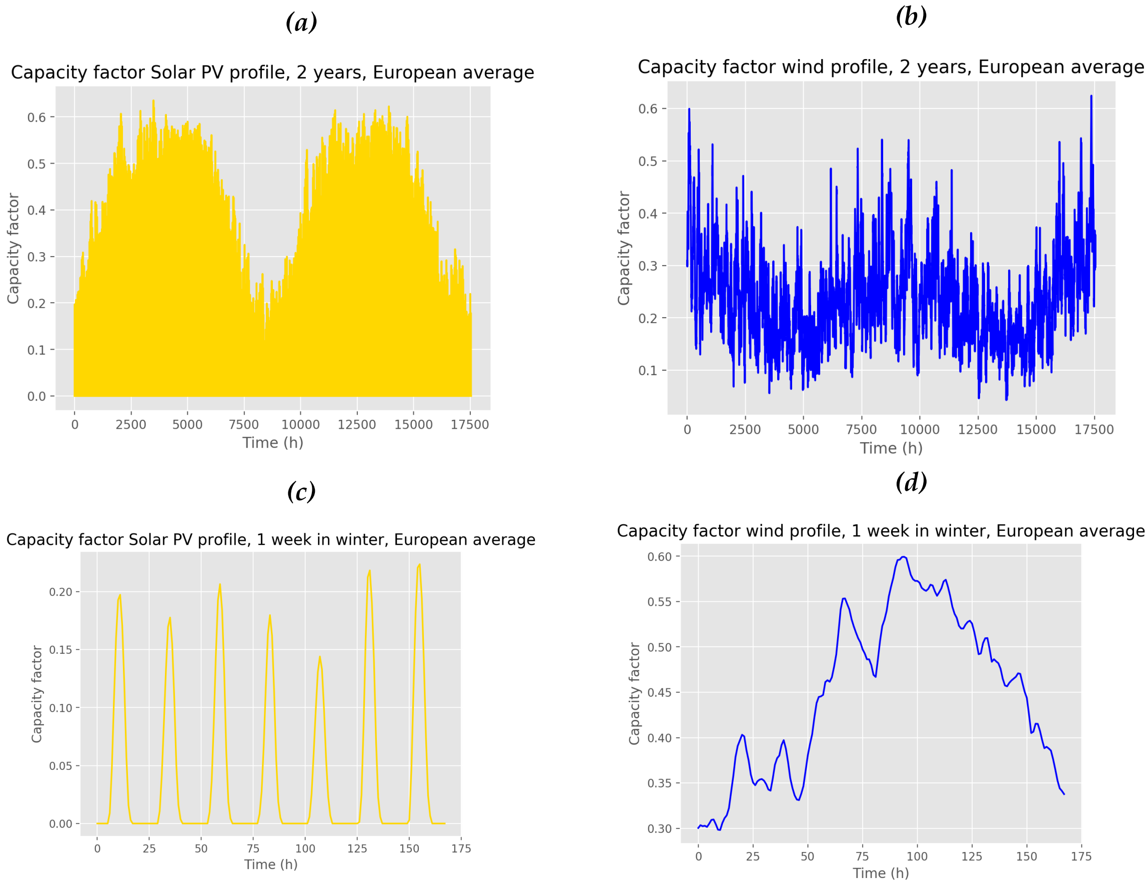

Figure 3.5: *Solar PV and Wind capacity factors for 2012 and 2013:* ***(a)*** *solar PV, 2 years* ***(b)*** *wind, 2 years* ***(c)*** *solar PV, 1 week in winter* ***(d)*** *wind, 1 week in winter (Pfenninger and Staffell, 2016)*

Country	**Code**	**PHS capacity (MWh)**	**Country**	**Code**	**PHS capacity (MWh)**
Austria	AT	98075	Hungaria	HU	0
Belgium	BE	0	Ireland	IE	0
Bulgaria	BG	2750	Italy	IT	202375
Switzerland	CH	436000	Lithuania	LT	0
Chzechia	CZ	2325	Luxembourg	LU	0
Germany	DE	4700	Latvia	LV	0
Denmark	DK	0	Netherlands	NL	0
Estonia	EE	0	Norway	NO	245250
Spain	ES	593000	Poland	PL	0
Finland	FI	3000	Portugal	PT	22250
France	FR	152000	Romania	RO	0
Gr Britain	GB	152925	Sweden	SE	75
Greece	GR	0	Slovenia	SI	0
Croatia	HR	0	Slovakia	SK	0

Table 3.7: *The table presents the maximum technical potential for pumped hydro storage, representing the maximum amount of pumped hydro storage capacity that can be installed within the specific country (Gimeno-Gutiérrez and Lacal-Arántegui, 2013)*

prolong an electricity peak by one hour. Furthermore, the fact that the sun sets earlier in winter due to Norway's close position to the North pole, would influence peaks and valleys. The regions are considered small enough that these differences do not significantly impact the load profiles.

3.4.2 Evaluation of Capacity Factors

A comprehensive set of input data is provided by Pfenninger and Staffell (2016). They provide hourly capacity factors for intermittent renewable energy in 28 countries of the European Union, including Switzerland and Norway. This set of data provided the required input data to model the hourly profile that both solar PV and wind power follows, for all countries in Europe.

Because of computational limitations, this research considers regions consisting of multiple countries rather than individual countries (this is further elaborated on in chapter 4). When constructing capacity factors for regions, the hourly capacity factor could not just simply be averaged out over different countries in the region. This would disproportionately alter the capacity factors: a country with a high capacity factor for that does not contribute by actually producing wind, will unjustly push up the regions capacity factor. The method used by Pfenninger and Staffell (2016), describes how the capacity factor was aggregated by dividing hourly production data by the installed capacity. Similarly, by adding the countries production for each region and dividing by their combined installed capacities, a weighted average capacity factor per region is obtained, based on its current installed capacity. This is illustrated by equation 3.2.

$$CF_{R,t} = \frac{\sum\limits_{n \in R} CF_{n,t} * ICn,t}{\sum\limits_{n \in R} IC_n} \quad \forall n \in R \;\; \forall R \;\; \forall t \in T \tag{3.2}$$

Variable	Description
$CF_{R,t}$	Capacity factor of region R at hour t
$CF_{n,t}$	Capacity factor of country n at hour t
IC_n	Currently installed capacity in region n
R	Set of regions
n	Set of countries
T	Set of hours

Table 3.8: *Explanation of variables that belong in equation 3.2*

The capacity factor for nine regions of Europe is then evaluated for desired and undesired correlations. The capacity factors in the model should be a good representation of reality, their reciprocal relation should show some correlation between regions in close proximity, but their correlations should be less if both regions are positioned further away from each other. Table 3.9 provides the correlation coefficients for each region for solar PV capacity factors. Table 3.10

	BI	SC	GE	IT	IB	FR	FB	CE	BG
BI	1	0.87	0.891	0.854	0.889	0.91	0.785	0.824	0.775
SC	0.87	1	0.915	0.862	0.805	0.87	0.872	0.857	0.852
GE	0.891	0.915	1	0.922	0.873	0.937	0.871	0.941	0.877
IT	0.854	0.862	0.922	1	0.903	0.933	0.841	0.914	0.921
IB	0.889	0.805	0.873	0.903	1	0.946	0.723	0.828	0.793
FR	0.91	0.87	0.937	0.933	0.946	1	0.803	0.879	0.841
FB	0.785	0.872	0.871	0.841	0.723	0.803	1	0.871	0.864
CE	0.824	0.857	0.941	0.914	0.828	0.879	0.871	1	0.893
BG	0.775	0.852	0.877	0.921	0.793	0.841	0.864	0.893	1

Table 3.9: *Correlation coefficients for Solar PV capacity factors of 9 regions in Europe in 2012 and 2013, based on the data provided by Pfenninger and Staffell (2016)*

	BI	SC	GE	IT	IB	FR	FB	CE	BG
BI	1	0.325	0.497	0.073	0.115	0.446	0.176	0.185	0.076
SC	0.325	1	0.599	0.062	0.019	0.179	0.534	0.593	0.026
GE	0.497	0.599	1	0.148	0.057	0.526	0.231	0.65	0.067
IT	0.073	0.062	0.148	1	0.336	0.187	0.023	0.244	0.378
IB	0.115	0.019	0.057	0.336	1	0.311	0.043	0.033	0.104
FR	0.446	0.179	0.526	0.187	0.311	1	0.08	0.206	0.026
FB	0.176	0.534	0.231	0.023	0.043	0.08	1	0.374	0.029
CE	0.185	0.593	0.65	0.244	0.033	0.206	0.374	1	0.144
BG	0.076	0.026	0.067	0.378	0.104	0.026	0.029	0.144	1

Table 3.10: *Correlation coefficients for wind power capacity factors of 9 regions in Europe in 2012 and 2013, based on the data provided by Pfenninger and Staffell (2016)*

The correlation coefficients show the extent to which regional capacity factors are correlated. In general, solar PV patterns are correlated more than wind patterns. A large part of this correlation can be explained by day and night patterns of solar influx. Wind patterns are less dependent on day and night patterns, which is reflected in the lower overall capacity factors.

As expected, both correlation coefficients show more correlation for regions nearby than for regions that are further away. For example, Bulgaria and the British Isles have a correlation coefficient of 0.775 and 0.076 for solar and wind respectively, while Germany and France have a correlation coefficient of 0.937 and 0.526 for solar and wind respectively.

All capacity factors between regions are correlated as expected, which means that the capacity factors provide a reasonable representation of energy production based on weather patterns of different regions. The aggregation into regions according to the method explained in equation 3.2 did not lead to significant changes (i.e. no unwanted correlation). Therefore, the set of aggregated regional capacity factors is acceptable for modelling electricity production from renewable energy sources.

3.5 Model Verification

After completion of implementation of the simulation model, a basic representation of a real-world problem has been formulated. A pathway from a real-world problem to a computer simulation tool is subjected to a series of funnels of simplification and conceptualisation, causing the researcher to rightfully concern itself with the question of whether the fnal result is a reasonable approximation of the problem that he or she begun with. Verification is a method used to assess whether the formalised model is a correct implementation of the conceptual model. The main question that is associated with verification is, did I build the thing right? According Sargent (2004), two main steps can be identified within the verification paradigm: *Specification verification* and *implementation verification*. Addressing the concern whether the underlying assumptions of the computer simulation tool are suitable for translation of the conceptual model to a computational model is known as specification verification. The question of whether the simulation tool was implemented according to the model specification (i.e. eliminating programming errors, correct implementation of what is said to be implemented) is known as implementation verification.

Section 3.5.1 shortly elaborates on specification implementation. Subsequently, the implementation verification process is logged in three sections. Section 3.5.2 explains how the model was verified through intermediate debugging and consistency checking with the Paters model. Section 3.5.3 explains the deployment of a minimal working model. Section 3.5.4 explains how the model was subjected to a series of logical tests, which confirmed the underlying assumptions of the main concepts of the model.

3.5.1 Verification of Python as Modelling Tool and CPLEX Solver

Python is one of the most widely used programming languages in the world. Writing any program in this language comes with its advantages. Other operating systems are compatible with python, so the exchange of information between different operating systems is possible with only minor code adjustments. Furthermore, the universal application of the Python language increases the chances that this model can be integrated into other models or programs. For modelling optimisation problems, numerous Python applications have been built. Some of them are Pulp, Pyomo, Gurobi and Cplex. The CPLEX solver has been chosen to model this problem. CPLEX requires data to be implemented as sparse pairs, which is a combined form of text and index numbers. However, when strings of names are used in an optimisation problem of this particular size, it will seriously hamper computational time. Table 3.11 shows how linear constraints should be added in order to minimise computational time. For this model, batches of indexed data were used to ensure allowance of maximum model size. The wide application of Python in combination with the CPLEX solver provides assurance that these tools are suitable for the specific implementation of a linear system costs optimisation model.

Model Size (# of variables)	**Default (sec)**	**Batching (sec)**	**Batching and w/o Name (sec)**
7500	22	13	0.24
15000	85	51	0.49
20000	150	93	0.70
30000	349	207	1.04

Table 3.11: *Relationship between data entry strategy and modelling time for CPLEX, showing how the number of variables and the optimization time are related, depending on the way in which the data is loaded into CPLEX, adapted from IBM (2014)*

3.5.2 Intermediate Debugging and Comparing Results to De Pater

The python program was run inside of an editor called Atom. Within this editor, the intermediate results were constantly printed to the interface. Throughout the modelling process, this

provided the opportunity to immediately check whether the programmed code yielded the desired results.
The model was constructed in segments, starting with only conventional generation for one country. Subsequently, renewable energy generation, countries (nodes), transmission and storage was added. For three key moments, the results were compared to the fully verified and validated equivalent of the MATLAB designed model by De Pater (2016). The exact input parameters were used in both models. The model code was reexamined until both models yielded the same results.

3.5.3 Minimal Working Model

In this section, the model is verified using a minimal working model. By creating a model that can be calculated by hand, the desired outcome is known beforehand. By comparing the by-hand calculation with the model outcome, the model outcome can be verified. To ensure an accurate by-hand calculation, the smallest possible problem was modelled that is still able to test important segments of the model. To this purpose, a two node system was modelled for the first 2 hours of 2012. The purpose of this model is to check whether transmission and renewable energy generation worked as it was meant to. The two nodes considered were the British Isles and Scandinavia, connected through a transmission line. The possibility of storage was taken out of the equation. For the first two hours of 2012, the objective was to provide the desired load in those hours, using the optimal configuration of renewable energy generation, therefore minimising the system costs. The problem was constrained to a maximum carbon intensity of 0, meaning that all power should be supplied by renewable energy. Since the capacity factor for solar PV at these hours is zero, this means only wind power is able to provide power.

3.5.4 Verification through Logical Testing

To further verify that the right system was built, the model was subjected to a series of logical tests. The outcome of these tests are obvious; the answer is found through simple logic. An example would be: "if all costs for gas power generation are set to zero and the CO_2 emission is unconstrained, then all power should be generated by gas power plants". To test whether the model provided the desired outcomes, logical tests were performed to verify the results in the four main segments of the model: conventional generation, storage, transmission and the CO_2 emission constraints. For each of the above-mentioned categories, the systems installed capacity, generation, transmission and system costs were obtained.

Regional Setup and Scenario Selection

Now that the model has been verified, I-E-Energy is ready to be deployed as an optimisation tool to find an optimal set of generation technologies based on the input parameters that are decided on by the researcher. The limitations have been discussed in previous sections, the task at hand is to select three scenarios, the results of which provide enough information to answer the research questions. The regional setup is discussed in section 4.1. Subsequently, the scenario selection is discussed in section 4.2. Finally, the scenario setup for Powerfys is discussed in section 4.3.

4.1 Regional Setup

The data input data for renewable energy production (Pfenninger and Staffell, 2016) and the consumption data (ENTSO-E, 2015) cover all of Europe. However, due to computational limitations, it was not possible to model all these countries separately, the number of variables would be so large that the computation time becomes impossibly long and the model produces out of memory errors. Therefore, countries are subdivided into regions, according to the ”copper plate” principle: power is assumed to flow unconstrained within the borders of a country or region (Després et al., 2015). This implies that there are no constraints between all generation technologies and demands within a specific region that was established as a copper plate. In this research, the regions that are defined are considered copper plates. A region has one node for which supply must match demand on an hourly basis. The demand of all countries in a region is simply added as if it were one country. The renewable energy production data is averaged, based on its current installed capacity (that is also how the dataset was created). Figure 4.1 provides an overview of the regions of Europe that were selected.

Table 4.1 gives an overview of the region names, their abbreviations and the countries incorporated in the regions. From here onward, the regions will be referred to by their names or abbreviations, instead of mentioning the countries separately.

Choice of Technologies
Another option to decrease the computational power and time is by decreasing the number of technologies incorporated in the model. To determine which technology can be eliminated, a

Region	Abbreviation	Countries included
British Isles	BI	United Kingdom, Ireland
Germany and Benelux	GE	Germany, Belgium, the Netherlands, Luxembourg
France	FR	France
Iberian Peninsula	IB	Spain, Portugal
Scandinavia	SC	Norway, Denmark, Sweden
Italy and the Alpine States	IT	Italy, Croatia, Austria, Switzerland, Slovenia

Table 4.1: *Region names, Corresponding abbreviations and Countries within the regions*

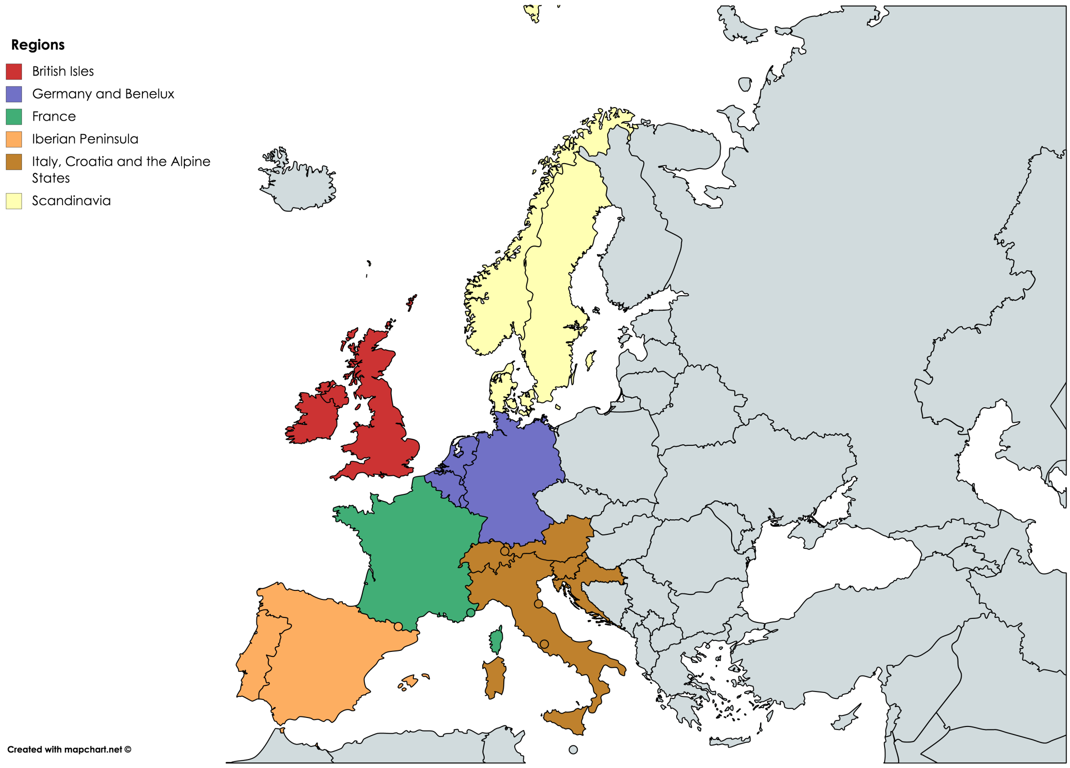

Figure 4.1: *provides an overview of the regions of Europe that were selected. Every colour represents one region. This map is created using a web-based mapchart tool (Mapchart.net, 2016)*

run was performed with maximum allowable hourly resolution (one full year) and maximum allowable regions (6 regions), both with and without an emission cap. It was found that in every situation (2010, 2050, with CO_2 cap and without, with all technologies included) there was no installed capacity for flow batteries. It was therefore decided to drop this technology.

4.2 Scenario Selection

Several test runs were performed, varying time-series, the number of regions and the number of technologies. The limits of the computational power were tested, resulting in a careful selection of three scenarios, based on sets of input parameters that were large enough to provide an answer to the research questions, while maintaining both computational performance and the ability to integrate the linear model results in the Powerfys model. The following subsections discuss the three scenarios that were selected.
Two main constraints are implemented to find an answer to the research question:

- The emissions constraint, which caps the maximum emission at the emission determined by the Paris agreement;
- The effect of implementing carbon capture and storage

4.2.1 Future System design, Reference Scenario

The reference scenario refers to a scenario without any constraints. It is a model formalisation of the cost-optimal scenario that corresponds to the current emission level of 550 gCO_2/kWh. The reference scenario does not include any carbon capture and storage technologies. These technologies would never be chosen by the model: they are more expensive and their only advantage is a low emission factor. The parameters that were chosen as modelling parameters in this particular scenario are described in table 4.2.

Modelling Parameter	Modelling Decision
Scenario Name	REF
Year	2050
Regions included	British Isles, Germany and Benelux, Scandinavia, France, Iberian Peninsula, Italy and the Alpine States
Time-series	full year, 2012
Generation technologies	solar, wind, coal, gas, biomass
Storage technologies	pumped hydro storage (PHS), hydrogen storage (H2)
Transmission	neighbouring countries
RES requirement	no
CO_2 constraint	0.55 $kgCO_2/kWh$
CCS	not included

Table 4.2: *Setup for the 2050 reference Scenario*

4.2.2 Future System design, 2°C Scenario

The 2°C scenario refers to a scenario in which the same technologies are modelled, but are constrained by a maximum allowable carbon intensity, which is discussed in section 1.1. The other parameters were kept equal. No carbon capture storage was implemented in this scenario.

Input Parameter	Modelling Decision
Scenario Name	CAP
Year	2050
Regions included	British Isles, Germany and Benelux, Scandinavia, France, Iberian Peninsula, Italy and the Alpine States
Time-series	full year, 2012
Generation technologies	solar, wind, coal, gas, biomass
Storage technologies	pumped hydro storage (PHS), hydrogen storage (H2)
Transmission	neighbouring countries
RES requirement	no
CO_2 constraint	**0.018 $kgCO_2/kWh$**
CCS	not included

Table 4.3: *Setup for the 2050 2 °C scenario without Carbon Capture and Storage*

4.2.3 Future System design, 2°C Scenario with Carbon Capture and Storage

Lastly, a scenario is run with an emission constraint congruent to a 2°C scenario, offering the possibility of carbon capture and storage. The maximum allowable carbon intensity was set to 0.04 kg CO_2/kWh. The other parameters were kept equal.

Input Parameter	Modelling Decision
Scenario Name	CAP+CCS
Year	2050
Regions included	British Isles, Germany and Benelux, Scandinavia, France, Iberian Peninsula, Italy and the Alpine States
Time-series	full year, 2012
Generation technologies	solar, wind, coal, gas, biomass, coal CCS, gas CCS, biomass CCS
Storage technologies	pumped hydro storage (PHS), hydrogen storage (H2)
Transmission	neighbouring countries
RES requirement	no
CO_2 constraint	0.018 kgCO_2/kWh
CCS	included

Table 4.4: *Setup for the 2050 2 °C scenario with carbon capture and storage*

4.3 Running the Scenarios in Powerfys

The results from all three scenarios provided input parameters for Powerfys. The installed capacity, available renewable energy, electricity demand and nodes were written to excel files that exactly resemble Powerfys input files, using Python functions. As such, the capacity ratio of generation units was determined.

4.3.1 From CO_2 cap to CO_2 price

To align the two models, the CO_2 costs have to be determined. In Powerfys the emission cap is not implemented: if one of the other constraints forces a more polluting plant to be dispatched, forcing the total generation over that cap, a solution could be infeasible. Powerfys does not have the possibility of increasing renewable energy, storage or transmission capacity. Therefore, the CO_2 constraint is implemented as a price for CO_2 emission. To determine the price of the CO_2 constraint, a series of runs was performed: the active CO_2 constraint was increased by 0.001 and decreased by 0.001, creating two supplementary scenarios to both active scenarios (in the REF scenario the CO_2 constraint is not active, so increasing and decreasing does not lead to any changes). The supplementary scenarios have slightly different objective functions and slightly different total CO_2 generation. The CO_2 price for each run was obtained by dividing the difference in CO_2 generation by the difference in CO_2 generation, for each supplementary scenario, relative to its active scenario. The CO_2 price is determined as the average between the supplementary scenarios. Table 4.5 provides the CO_2 costs for each scenario run.

Scenario	CO_2 constraint	CO_2 price (€/tCO_2)	Run Type
REF	0.55	0	Scenario
CAP	0.019	162	Supplementary
CAP	0.018	164	Scenario
CAP	0.017	166	Supplementary
CAP+CCS	0.019	81	Supplementary
CAP+CCS	0.018	80	Scenario
CAP+CCS	0.017	79	Supplementary

Table 4.5: *This table shows the CO2 costs determined for the three main scenarios, which are retrieved through supplementary simulation runs. The difference was used to determine the prices.*

4.3.2 Powerfys Scenarios

The outcome of the presented scenarios determines the capacity of electricity generation units. However, I-E Energy only calculates the installed capacity per region. The technical constraints that were discussed in section 3.1.3 only occur for separate units. To turn this model into a unit commitment problem, the installed capacity per region needs to be disaggregated.

Powerfys requires either separate units or aggregated units. However, when the units are aggregated, the optimisation converges to the I-E-Energy optimisation. To accurately model the effects of minimum generation, on/off time, ramping rates and startup costs, aggregated units per node are divided into separate entities.

The number of separated units should resemble a real world situation as much as possible. Unfortunately, increasing the number of generation units increases the computational time as well. Taking into consideration model accuracy and computational time, an appropriate strategy was applied. The widely distributed model outcomes for installed capacity prevent consistency. Therefore, the choice was made to divide the units into a large amount of small and medium units, and a small amount of larger ones. The capacity of each unit was subtracted from the aggregate capacity until the remaining aggregate capacity was smaller than the individual capacity. The aggregate represents what is left.

Every unit was divided into a maximum of 7 small units of 500 MW and subtracted from the aggregate capacity. For the installed aggregate capacity left, a maximum of 7 larger units of 1000 MW was installed. If there was still capacity left, a maximum of 4 large units of 3000 MW was subtracted from the aggregate. The remaining capacity was divided into 5000 MW units until the remaining capacity did not amount to 5000 MW anymore. The left over capacity remained an aggregate capacity. The reference scenario is presented in table 4.6, the scenario with the cap implemented without CCCS is presented in table 4.7 and the scenario with cap and CCS availability is presented in table 4.8.

Scenario 1: Reference Scenario (REF)

Unit Name	Unit Capacity (MW)	# of Units	Installed Capacity (MW)
Small	500	78	39000
Medium	1000	59	59000
Large	3000	27	81000
Huge	5000	32	160000
Aggregated	n/a	12	13883
Total	n/a	208	352883

Table 4.6: *The installed capacity determined through I-E-Energy leads to the division of units implemented in Powerfys shown here. This table shows the division for the reference scenario (REF).*

Scenario 2: Emission Constrained (CAP)

Unit Name	Unit Capacity (MW)	# of Units	Installed Capacity (MW)
Small	500	28	14000
Medium	1000	23	23000
Large	3000	12	36000
Huge	5000	22	110000
Aggregated	(-)	4	6526
Total	(-)	89	189526

Table 4.7: *The installed capacity determined through I-E-Energy leads to the division of units implemented in Powerfys shown here. This table shows the division for the scenario with the emission cap implemented (CAP).*

Scenario 3: Emission Constrained and CCS (CAP)

Unit Name	Unit Capacity (MW)	# of Units	Installed Capacity (MW)
Small	500	84	42000
Medium	1000	72	72000
Large	3000	29	87000
Huge	5000	56	280000
Aggregated	n/a	12	21993
Total	n/a	253	502993

Table 4.8: *The installed capacity determined through I-E-Energy leads to the division of units implemented in Powerfys shown here. This table shows the division for the scenario with the emission cap and the option of CCS implemented (CAP+CCS).*

Results

In this chapter, the results are presented. It shows the results of the analysis that was conducted, based on the research objective and the research questions that accompany it. The results give insight in 1) how the energy system should be designed in a cost-optimal way, in order to abide by the goals set in the COP21 agreement, 2) the role of carbon capture and storage in that system, 3) the effect of technical constraints on operational costs, generation of electricity, transmission and storage. Section 5.1 discusses the results of simulations performed by I-E-Energy, on a system level. Section 5.2 elaborates further on the inter-regional differences between the regions. Section 5.3 shows the results of a comparative analysis based on two models: I-E-Energy and Powerfys. Section 5.4 further elaborates on the inter-regional differences of both models.

5.1 System Results

In this section, the results for the future energy system as a whole are discussed. The results are presented in order of importance. Subsection 5.1.1 shows the levelised cost of electricity (LCOE) for three separate scenarios. In subsection 5.1.2, the systems installed capacity for energy generation are shown. Subsection 5.1.3 elaborates on the installed transmission capacity and subsection 5.1.4 gives insight into the storage and conversion capacities in three scenarios.

5.1.1 System Levelized Cost of Electricity

The levelised cost of electricity for each of the three scenarios determined in chapter 4 was calculated. The unconstrained scenario is referred to as REF, the scenario with the cap implemented is referred to as CAP and the scenario with the cap implemented and with the possiblity to implement CCS is called CAP+CCS. The results are presented in figure 5.1. The reference scenario (REF) is the cheapest. As expected, implementing the emission constraint (CAP) increases the system cost of electricity. Additional carbon capture and storage technologies are capable of reaching a system design with the same emissions, at lower cost (CAP+CCS).

In both CAP and CAP+CCS, a significant share of the cost is allocated to renewable energy. However, in CAP+CCS, renewable energy production plays a more moderate role than in the CAP scenario. If carbon capture and storage is implemented, a large share of the system costs is shifted towards coal in combination with CCS. The relationship between renewable energy generation and the need for transmission and storage capacity becomes clear from scenario CAP and CAP+CCS. The cheapest way to an energy system that complies with the Paris agreement, without CCS, requires transmission and storage technology to account for variation in renewable energy. However, when CCS is implemented, it can generate power regardless of unfavourable weather conditions. Generation of wind and solar PV is then dispatched optimally and the need for storage and transmission is slightly reduced. In all three scenarios, a preference for wind energy can be observed over solar energy.

Transmission and storage costs are increased in a scenario with the emission cap implemented. This result was expected since this scenario inhibits large costs for renewable energy generation

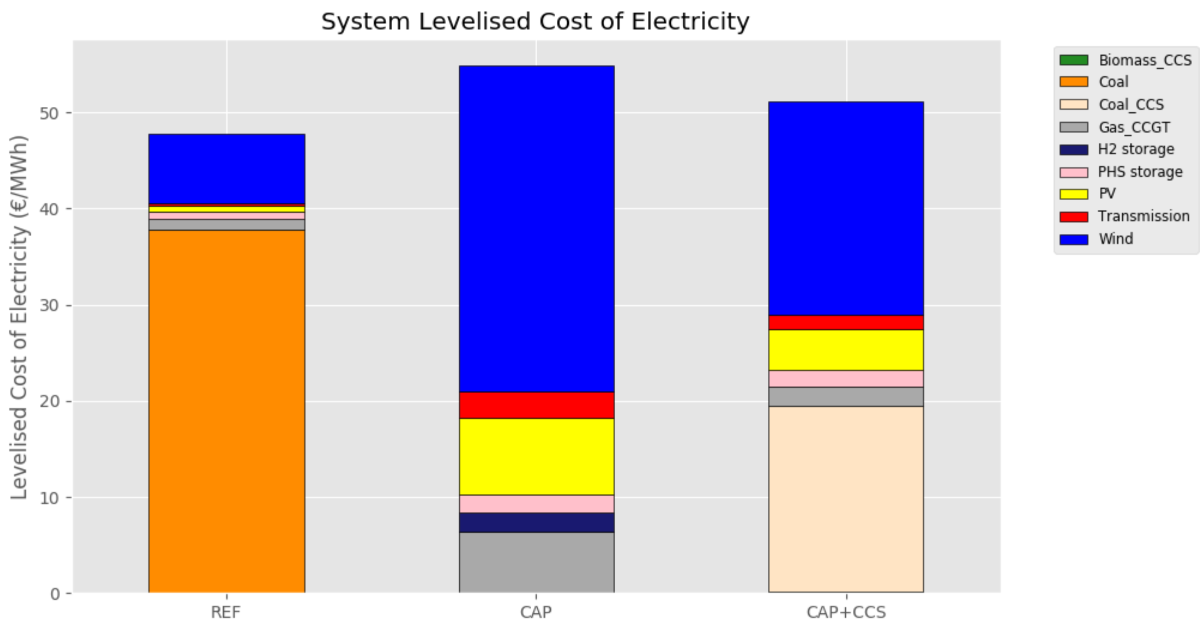

Figure 5.1: *This figure shows the System levelised cost of Electricity (LCOE) for all three scenarios considered. The reference scenario (REF), unconstrained, is shown left. The emission constraint is implemented with the same technology parameters (CAP), and the results are shown in the middle. The results for the option of CCS implemented (CAP+CCS) are shown on the right. The total costs are divided by the total amount of electricity produced; the results are in €/MWh. The results are obtained with I-E-Energy.*

both from solar PV and wind. The flexbility requirement is increased, which leads to installation of transmission capacity, pumped hydro storage and hydrogen storage. The scenario with the cap and CCS implemented requires more transmission and more storage than the reference scenario, but less than a scenario without CCS. Since less storage is required, pumped hydro storage is sufficient to fulfil that function. This is congruent to costs allocated to renewable energy, which is more than the reference scenario, but less than the cap without CCS scenario.

In an energy system where CO_2 is captured through CCS, a large chunk of the costs will be allocated to fuel costs for coal. The negative emissions from biomass are used to offset CO_2 emitted by coal. However, this effect is quire small. Also, a significant amount of costs allocated to gas are now allocated to coal with CCS. The emission of coal with CCS is significantly lower compared to regular gas, allowing for more coal CCS plants to be installed and/or used. This reduces the flexibility requirements while respecting the CO_2 constraint.

5.1.2 System Installed Generation Capacity

The installed generation capacity of the system under different scenarios is shown in figure 5.2. This figure shows only the units capable of delivering electricity. Storage, conversion and transmission are elaborated on in the sections that follow.

Figure 5.2 shows that an optimal system design under a carbon emission constraint requires a large amount of installed renewable energy capacity, compared to the reference scenario. However, when carbon capture storage is included in the optimisation, the total installed generation capacity is reduced significantly. This means that fulfilling the demand using renewable energy requires a larger amount of installed generation capacity then if it is fulfilled with coal in com-

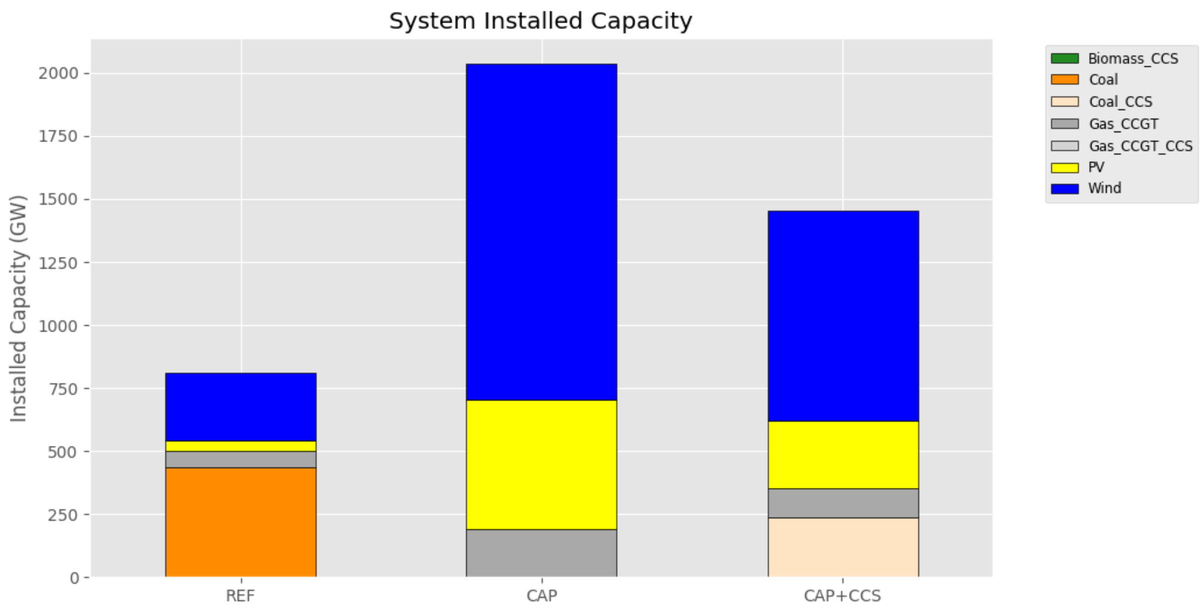

Figure 5.2: *This figure shows the generation capacity (LCOE) for all three scenarios considered. The reference scenario (REF), unconstrained, is shown left. The emission constraint is implemented with the same technology parameters (CAP) and the results are shown in the middle. The results for with the option of CCS implemented (CAP+CCS) is shown on the right. The installed capacities are shown in GW.*

bination with CCS.

This effect can be explained by the capacity factors for renewable energy. During long periods without sun and wind across the whole continent drain the storage units. By the time that they are empty, there is either the option of using conventional plants or biomass. Since biomass requires large investments and has high operational costs, the model does not consider this a viable option. The emission constraint prevents further utilisation of conventional plants. Hence, it is cheaper to install renewable energy units. The production capacity during that particular period is dependent on the capacity factor, which is low if there is no wind or sun. Therefore, yield (generated power) is low as well. In order to satisfy the hourly load regardless, a large amount of generation capacity needs to be installed.

5.1.3 Installed Transmission Capacity

Figure 5.1 shows that part of the costs for electricity is attributed to the to be built transmission network. This subsection further elaborates on the amount of transmission capacity constructed between the regions of the model and the location of the lines. Figures 5.3 , 5.4 and 5.5 show the transmission capacity that will be installed for the REF, CAP and CAP+CCS scenario respectively.

Figure 5.3 shows that for an unconstrained future energy system, only small transmission lines are constructed. Electricity demand can be met without any constraints and coal is the cheapest option. Coal can be installed in all countries at the same price and electricity demand can be met without any constraints, so there is no incentive to transport electricity. The small amounts are reserved for moments when unused capacity in one region can be used in another.

Figure 5.3: *Map of Transmission lines between regions, Reference Scenario. The lines represent the installed transmission capacity between the geographical centers of the regions, according to the copper plate model.*

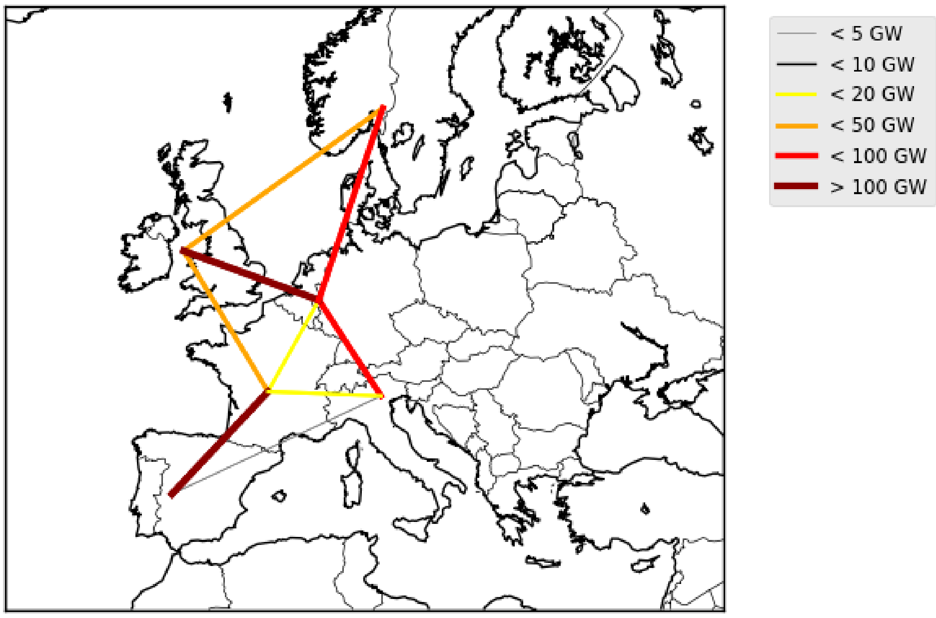

Figure 5.4: *Map of Transmission lines between regions, CO_2 constraint implemented, no CCS. The lines represent the installed transmission capacity between the geographical centers of the regions, according to the copper plate model.*

The CAP scenario (figure 5.4) requires a significantly larger transmission line capacity. The flexibility required to balance variable renewable energy is the most important reason for the requirements. Also, the largest transmission capacity lines are built for the areas with the most renewable energy: the Iberian Peninsula and the British Isles. Furthermore, transmission lines

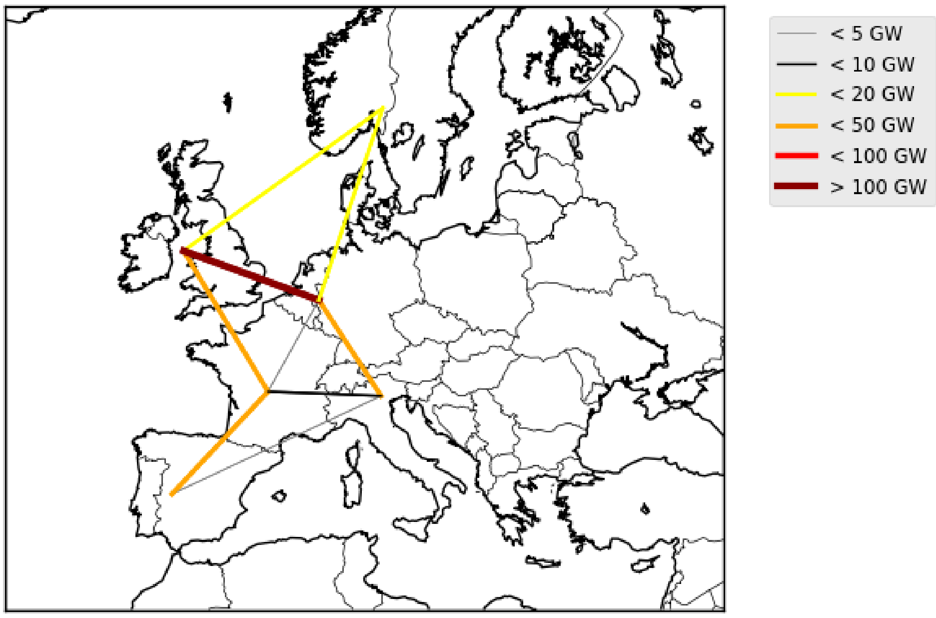

Figure 5.5: *Map of Transmission lines between regions, CO_2 constraint and CCS implemented. The lines represent the installed transmission capacity between the geographical centers of the regions, according to the copper plate model.*

are constructed along all possible connections.

In parallel with the required renewable energy generation capacity, transmission plays a smaller role in the CCS scenario. For the Levelised cost of electricity, the transmission account for a reasonably small amount, but figure 5.5 shows transmission installed, although less capacity is installed than in the CAP scenario.

In general, the transmission capacity requirement is linked to the deployment of renewable energy sources. Transmission increases the flexibility of the power system, increasing its ability to account for intermittent energy production patterns.

5.1.4 Installed Storage and Storage Conversion capacity

From figure 5.1 shows that a segment of the costs is attributed to investments in storage capacity. The size of these storage units is further illustrated by figure 5.6. The conversion capacity and storage reservoir capacity are shown in separate subfigures.

(a) The conversion capacity *(b) The capacity of the storage reservoir*

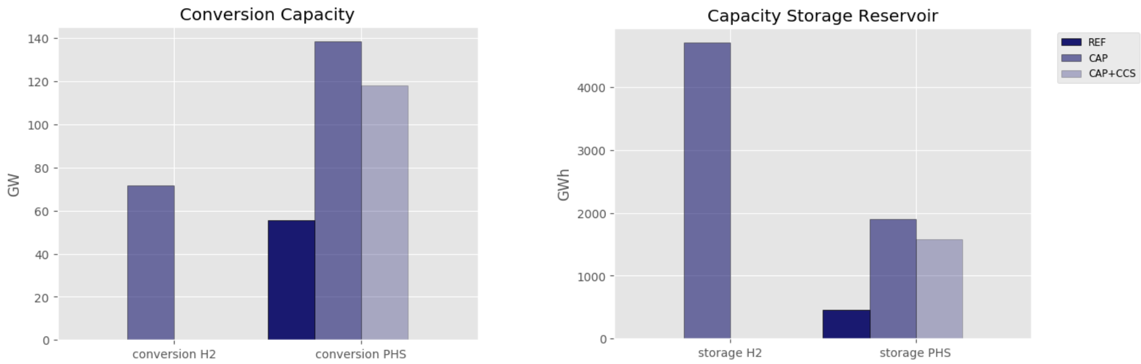

Figure 5.6: *Storage Capacities of the charger/discharger and the storage reservoir. Both considered storage options are shown hydrogen storage (H2) and pumped hydro storage (PHS). Both options are shown for three scenarios: the reference scenario (REF), the scenario with the emission constraint (CAP) and the scenario with the emission constraint, with CCS added as an option.*

Figure 5.6 an outcome that is consistent with figure 5.1: the reference scenario requires a small amount of storage capacity. The largest storage capacity, both conversion and reservoir capacity can be found in the cap scenario. As expected, both storage and transmission capacity is required to cope with the influx of intermittent power. Restrained by the emission constraint, the cheapest option of coal-fired generation is excluded. The cheapest storage option (pumped hydro storage) is fully exploited (until the technical limit is reached) and as a consequence, additional Hydrogen storage is installed.

Introduction of carbon capture and storage reduces storage requirement. This is an expected outcome: thermal generation in combination with CCS can be turned on at will (as long as other constraints are respected), meaning that it can substitute for stagnating renewable energy production as a result of weather patterns. The requirement for storage follows the same pattern as the transmission capacity across all three scenarios, for the same reason: to account for variable renewable energy sources.

5.2 Results Distributed Per Region

This section further elaborates on the results of all three scenarios presented how each region is affected. Subsection 5.2.1 discusses the fixed and variable costs distributed per region and section 5.2.2. Further elaboration into storage and transmission usage is discussed in the next section.

5.2.1 Fixed and Variable Costs Per Region

The levelised cost of electricity that is presented in subsection 5.1.1, consists of both fixed and variable costs. Figure 5.7 shows the fixed and variable costs for all three scenarios, distributed per region.

In terms of fixed and variable costs, there is a similarity between the reference scenario and the CCS scenario in the regions of France, Germany and Benelux and in to a lesser extend in Scandinavia. A similar division of fixed and variable costs can be observed. The CAP (middle) scenario in each region, shows little to no variable costs since most of the generation capacity is

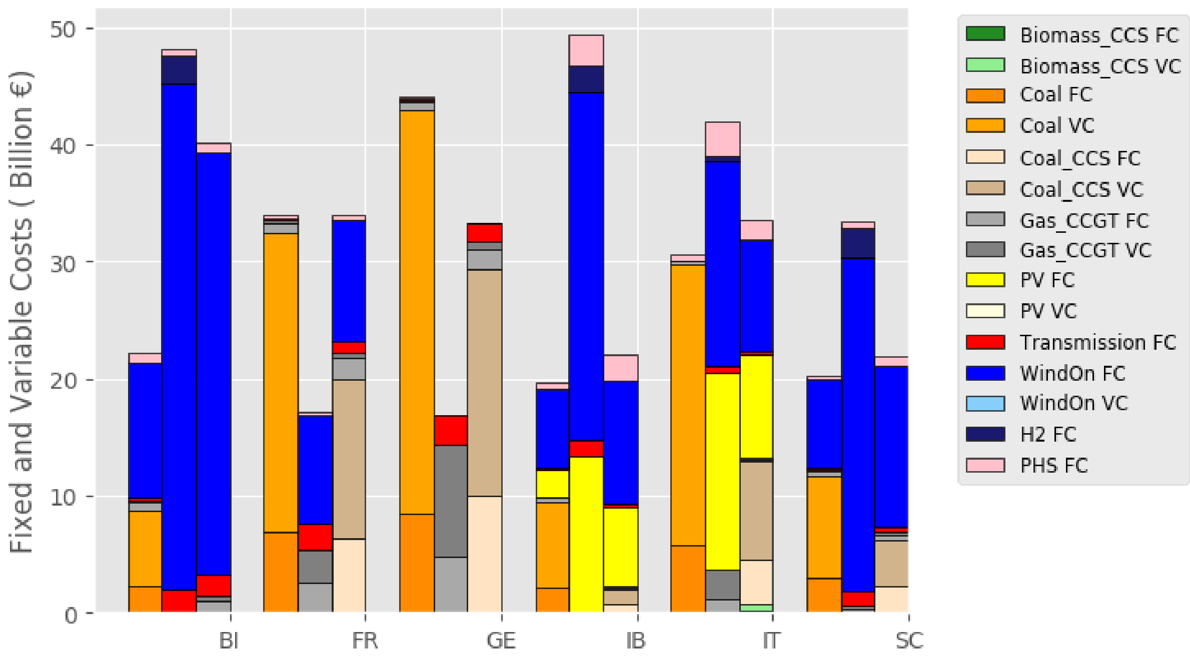

Figure 5.7: *Fixed and variable costs for each scenario, distributed per region. For each region, three bars are shown. Each bar represents the outcome for one scenario for that particular region. The reference scenario (REF) is shown left, the scenario with the emission constraint (CAP) is shown in the middle, the scenario with emission constraint and CCS (CAP+CCS) is shown right.*

attributed to wind and solar PV. Investment in transmission capacity is fairly limited and only plays a role in a low carbon regime without CCS (CAP scenario). Most flexibility (conventional generation, transmission and storage) is situated in the regions France and Germany. This is in line with the expectation: the more central nodes need to offer more flexibility. They, inhibit the highest variable costs. A tiny amount of the costs are attributed to biomass with CCS. Remarkably, the ratio between the fixed and variable costs for biomass with CCS is in favour of variable costs. This means that the biomass CCS plant is turned on. One could speculate that the biomass plant is turned on purely to offset CO_2 emissions, not necessarily to deliver electricity.

5.2.2 Distribution of Generation capacity per Region

Figure 5.8 shows the distribution of generation capacity over the different regions, for scenario REF, CAP and CAP+CCS (depicted from left to right in the figure).

For the reference scenario, generation capacity is mainly coal and is distributed fairly evenly among the different regions. The most generation capacity can be found in France and Germany. The Northern regions have wind power installed, but this amount is limited compared to the other two scenarios. The only region that has solar power is the Iberian Peninsula.

For the CAP scenario, solar PV and wind form the CAP largest contributors to the generation capacity. Solar energy is mainly situated in the southern regions, the Iberian Peninsula and Italy and the Alpine States. Wind energy is situated mostly in the Northern regions, the British Isles and Scandinavia. Remarkably, a fairly large share of wind energy situated on the Iberian Peninsula, while the capacity factor for wind in the Northern regions is higher. This can be explained by the fact the Iberian Peninsula forms an outlier, compared to for example Germany.

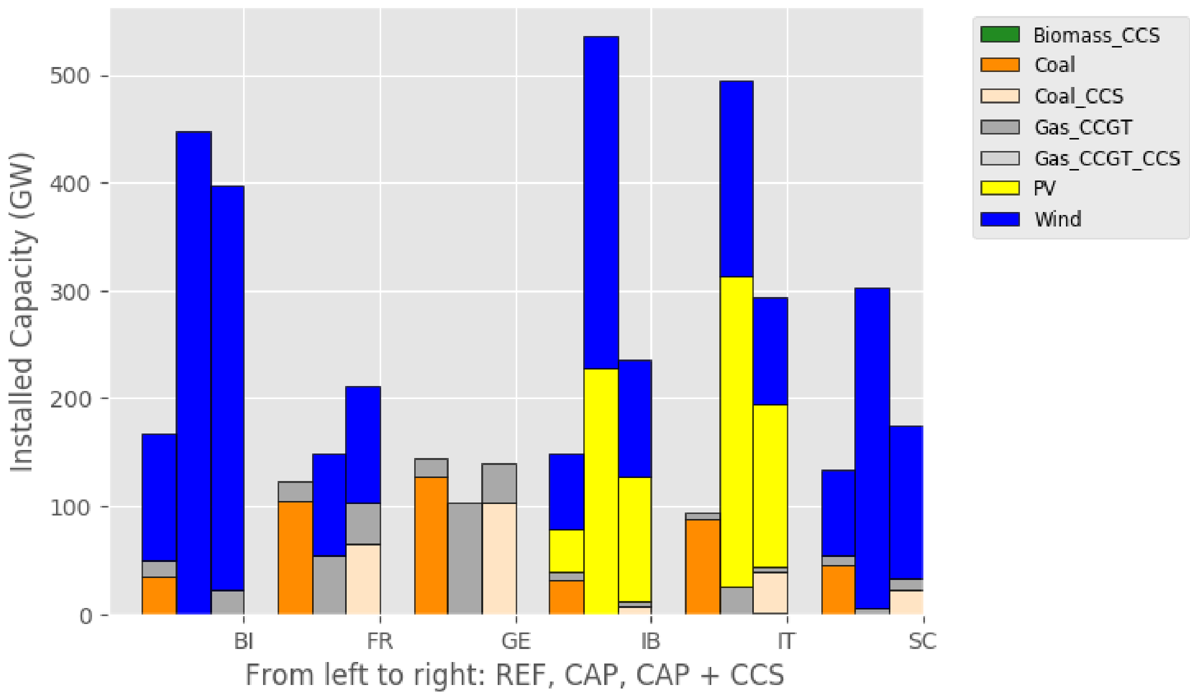

Figure 5.8: *Installed Generation Capacity for each scenario, distributed per region. For each region, three bars are shown. Each bar represents the outcome for one scenario for that particular region. The reference scenario (REF) is shown left, the scenario with the emission constraint (CAP) is shown in the middle, the scenario with emission constraint and CCS (CAP+CCS) is shown right.*

The consequence is that significant investment in transmission capacity is required to access electricity from northern regions. Taking into account transmission losses, this might offset the increased production of wind in the northern regions. In the CAP scenario, most conventional generation capacity is installed in the most centrally positioned nodes, Germany and France. These are the regions that are able to offer the most flexibility.

The CAP+CCS scenario yields similar results. Compared to the CAP scenario, less extreme amounts of generation capacity are required, but the observed trends are similar: mainly solar in the southern regions, wind in the northern regions and conventional generation (in this case with CCS) in Germany and France.

5.3 Model Comparison on a System level

This section discusses the results of the comparative analysis performed through simulation with I-E-Energy and Powerfys. The systems operational costs are compared in subsection 5.3.1, the total electricity generation is compared in subsection 5.3.3. Subsection 5.3.4 shows the CO_2 generation of both models.

5.3.1 Operational Costs

The system operational costs are shown in figure 5.9. The operational costs of the whole system for all three different scenarios are represented in this figure. The chart shows the results for I-E-Energy (left) and the results for the Powerfys model (right).

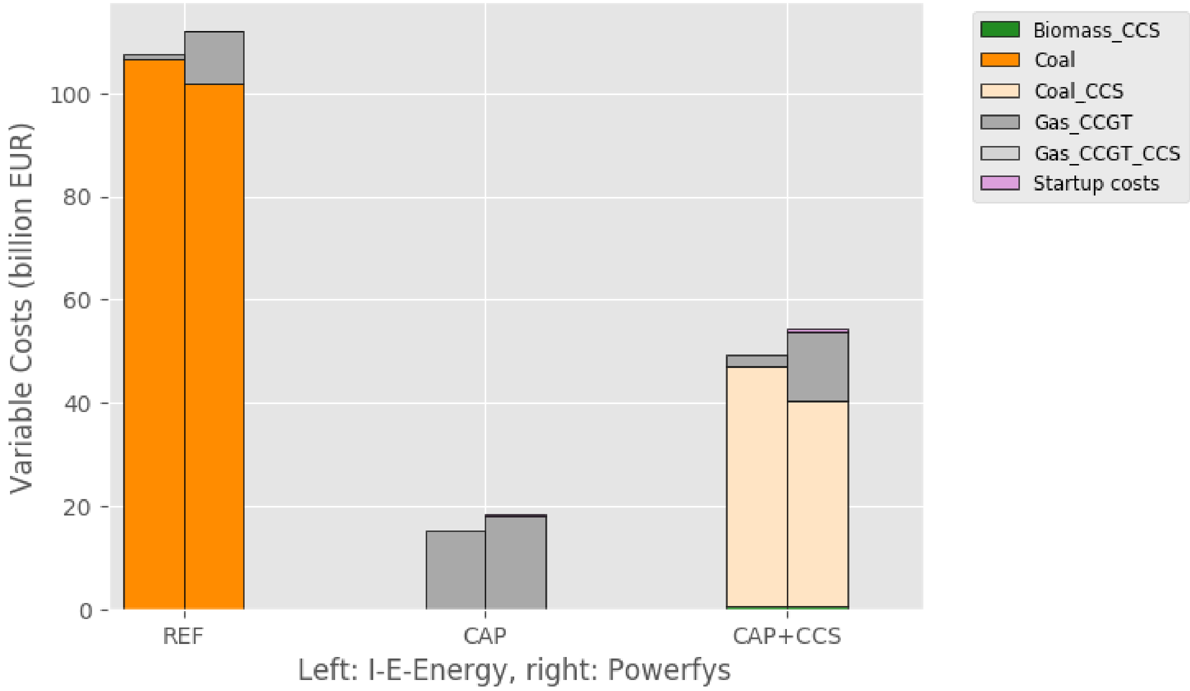

Figure 5.9: *System operational costs in 2050, under three scenarios, showing the system operational costs for I-E-Energy (left), and Powerfys (right)*

In all three scenarios, a run for a whole year performed with Powerfys results in increased operational costs. The operational costs increased by 4.3 %, 19.3 % and 10.3% for the three scenarios, respectively. These cost increases are mainly attributed to two effects: an increase in the use of gas-fired power plants in regard to coal-fired plants and start-up costs. In scenario one (REF), Powerfys allocated more costs to dispatching gas power plants. In scenario two (CAP), Powerfys allocates more costs to dispatching gas power plants. In scenario three (CAP+CCS), the costs are slightly shifted from coal with CCS to Gas with and without CCS. Startup costs can be observed in both the CAP and the CAP+CCS scenario. However, compared to the total variable costs of the system these seem to be marginal.

5.3.2 System levelised Cost of Electricity Comparison

The results of modelling with Powerfys are presented in figure 5.10. The chart shows the The levelised cost of Electricity for the whole system for all three different scenarios are represented in this figure. The chart shows the results for I-E-Energy (left) and the results for the Powerfys model (right).

Congruent to figure 5.9, the end result is an increase in costs for all three scenarios. While the increase in marginal costs for Powerfys can be substantial (almost 20% in the cap scenario), this comparison shows that on a system level, the results do not lead to large changes. The increase in levelised cost of electricity when technical constraints are taken into account are 2.59 %, 1.15 % and 2.40 % respectively.

5.3.3 Total Electricity Generation and Load Balance

Analogous to figure 5.3.1, the generation mix and the load balance of all three scenarios are represented in figure 5.11 and 5.12 respectively. Figure 5.11 shows the total electricity used by

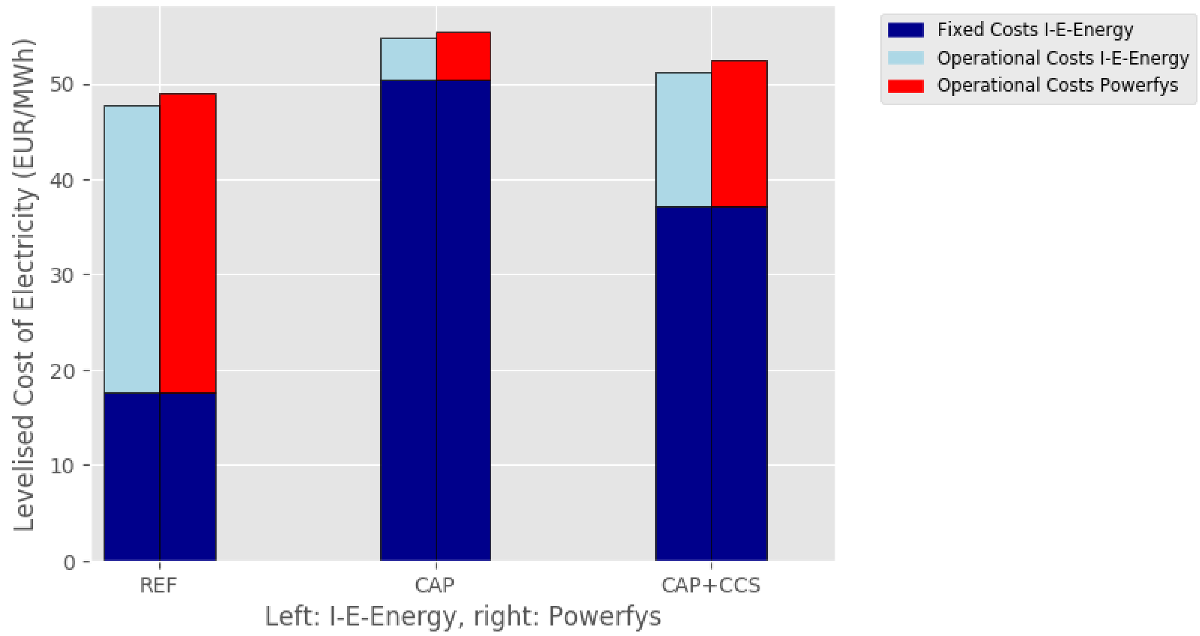

Figure 5.10: *Levelised Cost of Electricity for I-E-Energy in combination with Powerfys. The fixed costs are calculated with Powerfys, the variable costs are calculated with I-E-Energy and Powerfys*

both models to fulfil the demand. Figure 5.12 gives more insight into the distribution of the available electricity, including transmission losses, storage losses and curtailment of renewable energy.

The generation mix in figure 5.11 shows how the generation profile corresponds to the variable operational costs. Total generation of power is almost equal in both models in scenario REF. Slightly more power generation can be observed by I-E-Energy. Scenario CAP shows that I-E-Energy generates more electricity than Powerfys. In scenario CAP+CCS, I-E-Energy also generates (slightly) more electricity. The increased costs for gas-powered electricity generation in scenario REF and CAP+CCS are connected to the increased generation.

Figure 5.12 gives more insight into the allocation of electricity generation. From figure 5.11, the increased electricity generation also surpasses the electricity demand, which begs the question, what the destination is of this generated power. The demand (red line) is fulfilled in all three scenarios. The renewable energy that is available, is partly curtailed, and partly attributed to storage and transmission losses.

In the CAP scenario, I-E-Energy uses more storage capacity than I-E-Energy. The load balance in figure 5.12 shows how both models deal with that difference, Powerfys curtails this excess energy. Furthermore, a preference towards gas-fired generation can be seen in Powerfys. This can be partly related to stricter constraints for coal generation than gas power generation: Gas fired power plants have lower start-up costs, lower minimum generation, and lower on-times. These constraints are not taken into account by I-E-Energy and lead to higher overall costs. This effect occurs for individual generation units. However, there are internal differences in both models that cause disturbances of the results: the effects of turning a CO_2 cap into a price, the inability of Powerfys to model seasonal storage and the absence of transmission losses influence the model outcome. Therefore, more research is required to isolate these differences and study their individual effects. Nevertheless, transmission losses and storage usage are

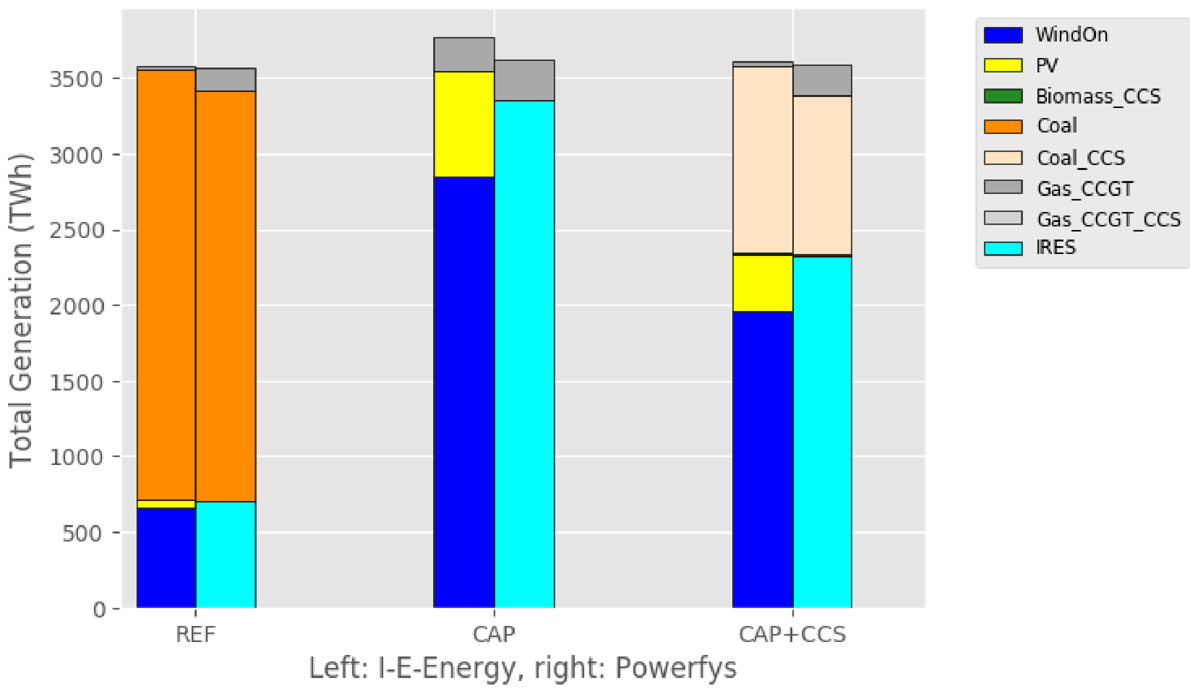

Figure 5.11: *Comparison of Generation mix in 2050, under three scenarios, showing the total generation per generation technology, with the left bars representing the outcome generated by I-E-Energy, the right bars showing the Powerfys results. IRES= intermittent renewable energy sources, which is the defined as the total available renewable energy (solar PV + Wind) minus the curtailment.*

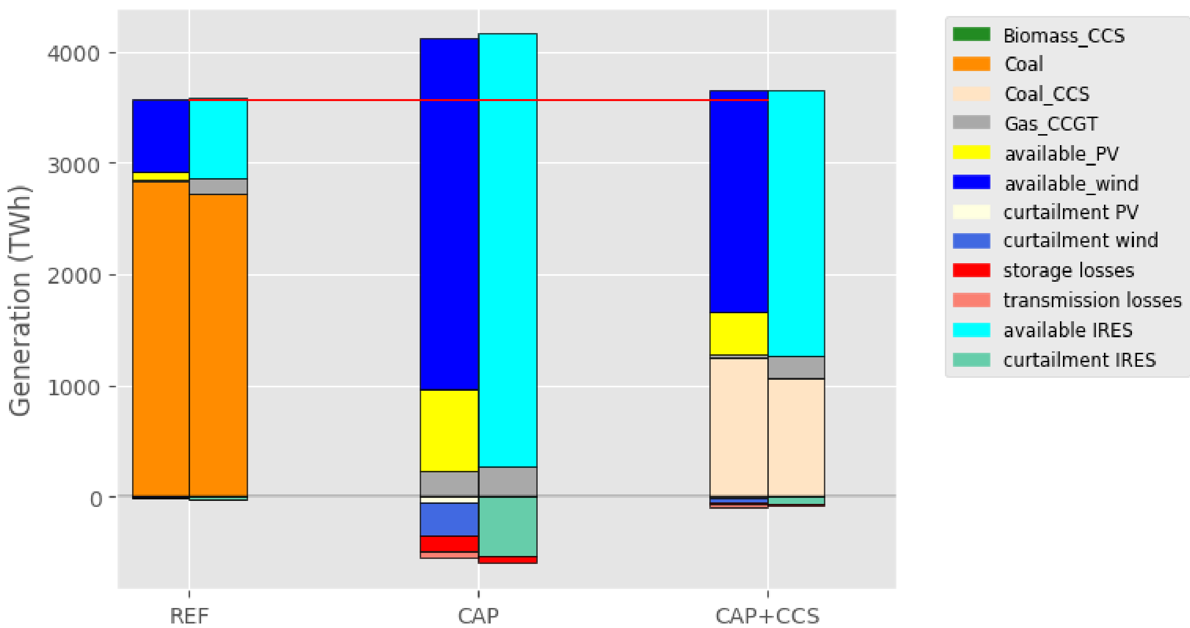

Figure 5.12: *The total load balance in 2050, under three scenarios, with the left bars representing the outcome generated by I-E-Energy, the right bars showing the Powerfys results. The figure shows the demand (depicted by the red horizontal line) the contribution of energy carriers to fulfil that demand. Everything above the red line is either an efficiency loss or curtailment of renewable energy, offset by the entities shown below the grey horizontal line (depicting zero)*

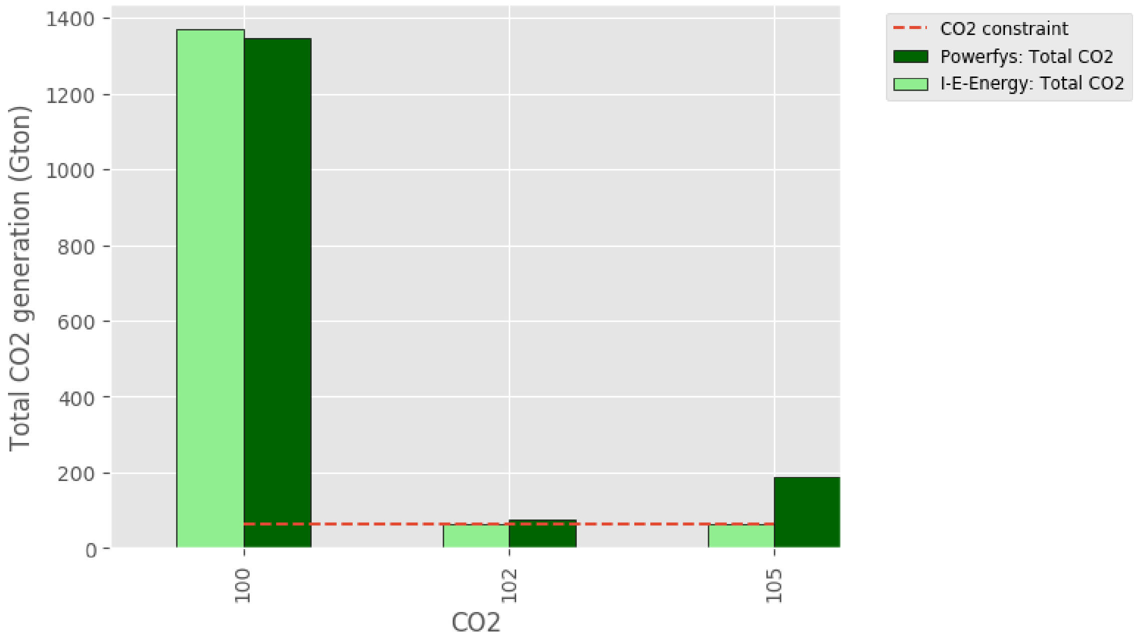

Figure 5.13: *In this figure, the total CO_2 generation can be observed, for three scenarios. From left to right, the reference scenario (REF) is not subjected to the CO_2 constraint, it is implemented in the CAP scenario and also in the scenario where CCS is implemented as an option (CAP+CCS). The total CO_2 emission that is allowed is determined through multiplication of the carbon intensity with the total generation of that particular scenario.*

a much smaller part of the total generation. Especially in the reference scenario, where both effects are minimal, the share of gas fired generation in the generation mix is significantly larger, which suggests that gas fired generation is required regardless of storage and transmission losses.

5.3.4 CO_2 generation

The total generation of CO_2 (in Gtons) is shown in figure 5.13. The reference scenario, of course, is not subjected to the constraint, so through coal-fired electricity generation, a huge amount of CO_2 is emitted. In the CAP scenario, the CO_2 constraint is slightly violated by Powerfys. For the run with CCS implemented, the CO_2 emission is not kept to the same minimum. Powerfys exceeds the emission constraint significantly.

5.4 Results of Model Comparison Distributed per Region

Following the results on a system level, this section further elaborates on the results per region. In subsection 5.4.1, the results of the regional distribution of electricity generation are compared for both models. Subsection 5.4.2 discusses the power transfer between regions and subsection 5.4.3 further elaborates on the storage usage of every region.

5.4.1 Electricity Generation per Region

Generation of electricity is distributed per region. The installed capacity that was determined in figure 5.8 shows varying capacities for all regions. Figure 5.14 shows how electricity generation is distributed across regions and how this distribution changes when the run is performed by Powerfys.

The renewable energy depicted in figure 5.14, is defined as the total available electricity minus curtailment. In general, the generation patterns are alike for both I-E-Energy and Powerfys. The most resemblance can be found in the reference scenario. The cap scenario and the scenario with CCS implemented show some differences. In the CAP scenario, a smaller share of electricity from renewable energy sources is curtailed. In this scenario, I-E-Energy utilises more transmission capacity and more storage capacity, meaning that the electricity generated is subjected to both transmission and storage losses. To account for these losses, I-E-Energy uses electricity that would otherwise be curtailed. In the CAP+CCS scenario, coal generation with CCS is used more than in Powerfys. This can be attributed to the technical constraints that are stricter for coal plants compared to gas fired plants.

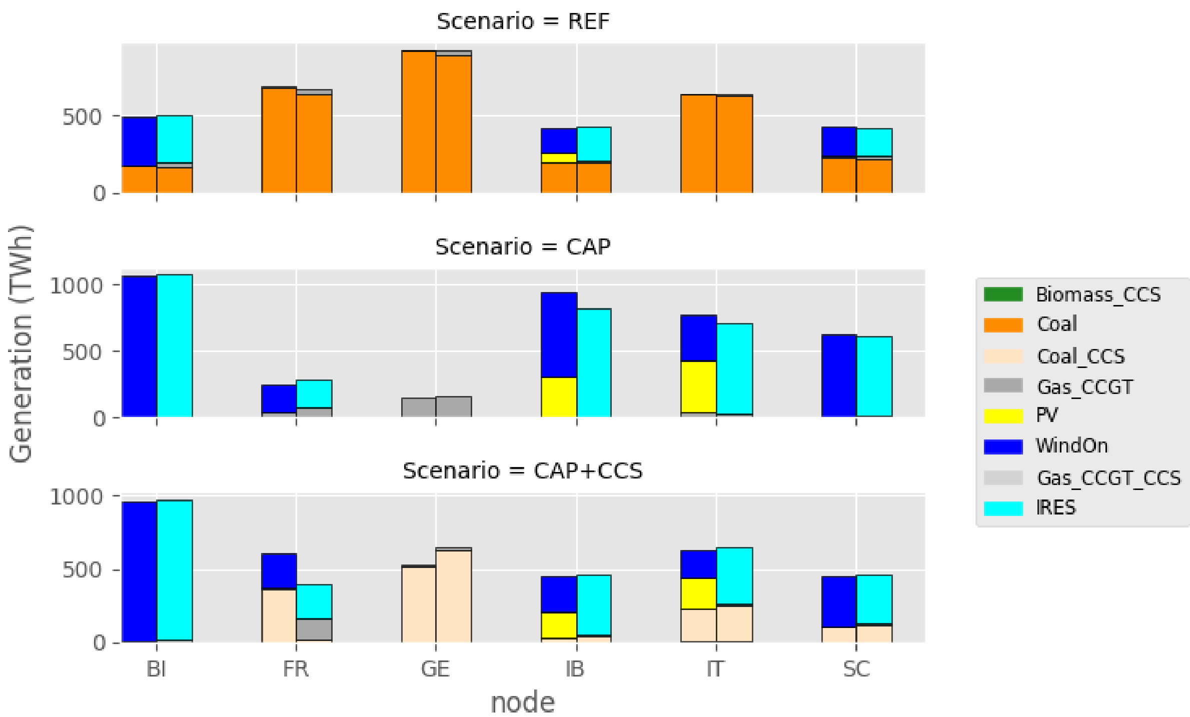

Figure 5.14: *This figure shows the distribution of electricity generation of Powerfys (all the left bars, recognised by the presence of IRES (Intermittent renewable energy sources) and I-E-Energy (all the right bars, recognised by the presence of PV and WindOn (= Wind). IRES in Powerfys is equivalent to the sum of wind and solar PV in I-E-Energy. The results are shown for the reference scenario (REF), the emission constraint implemented (CAP) and the emission constraint implemented with the option of CCS (CAP+CCS). From left to right, the bars show the 6 regions considered: BI = British Isles, FR = France, GE = Germany and Benelux, IB = Iberian Peninsula, IT = Italy, Croatia and the Alpine States, SC = Scandinavia.*

5.4.2 Power Transport between Regions

The power transfer between the regions was compared for both models. In figure 5.15, the total imported power and total exported power per region is shown. In figure 5.16, the net power transfer is shown (import-export). The regions that have a positive net power transfer, import power and vice versa.

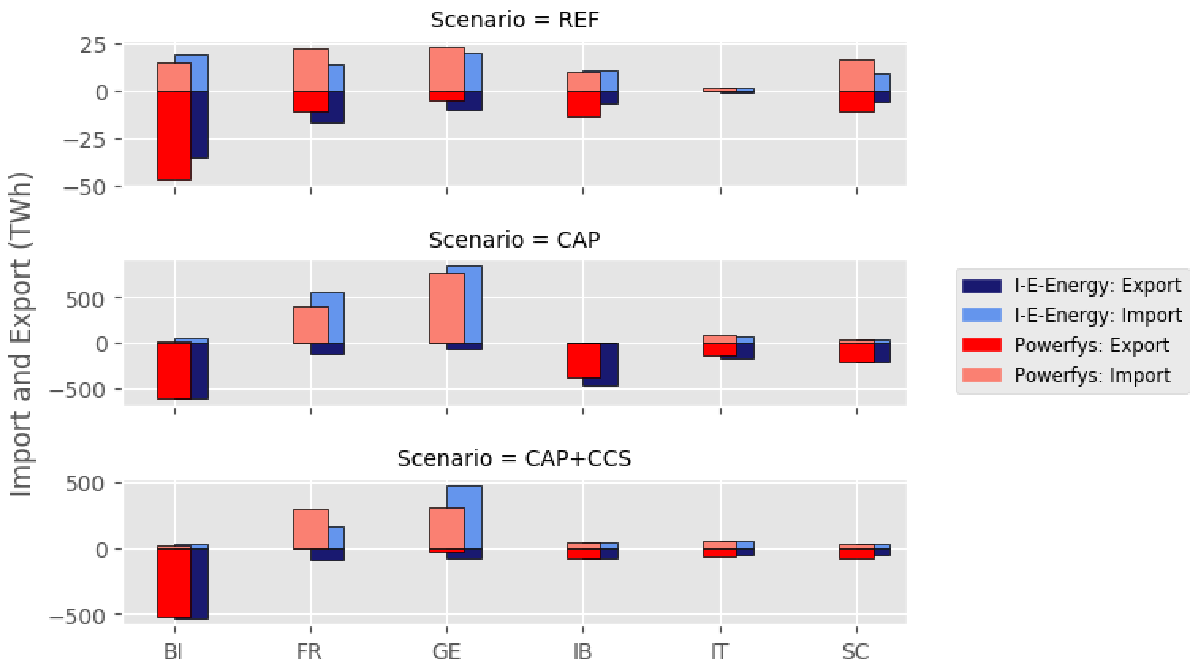

Figure 5.15: *Comparison of import and export betweenthe regions for all three scenarios, comparing Powerfys (red bars) and I-E-Energy (blue bars). From left to right, the bars show the 6 regions considered: BI = British Isles, FR = France, GE = Germany and Benelux, IB = Iberian Peninsula, IT = Italy, Croatia and the Alpine States, SC = Scandinavia.*

All three scenarios show import and export of power between the regions. However, some differences between the scenarios can be observed. Scenario REF shows little power transfer, while scenario CAP and scenario CAP+CCS show about a ten-fold increase in total import, as well as export. Congruent to the transmission maps in section 5.1.3, there is the most power import in the middle (cap) scenario, followed by the CAP+CCS scenario and the smalles power transfer can be observed in the reference scenario.

Both models follow similar import-export patterns, for all three scenarios. Overall, I-E-Energy imports and exports more power than Powerfys. Especially in the centrally located nodes, there is more import and export of electricity. This is remarkable since Powerfys does not include transmission losses. I-E-Energy uses more inefficient transmission capacity than Powerfys.

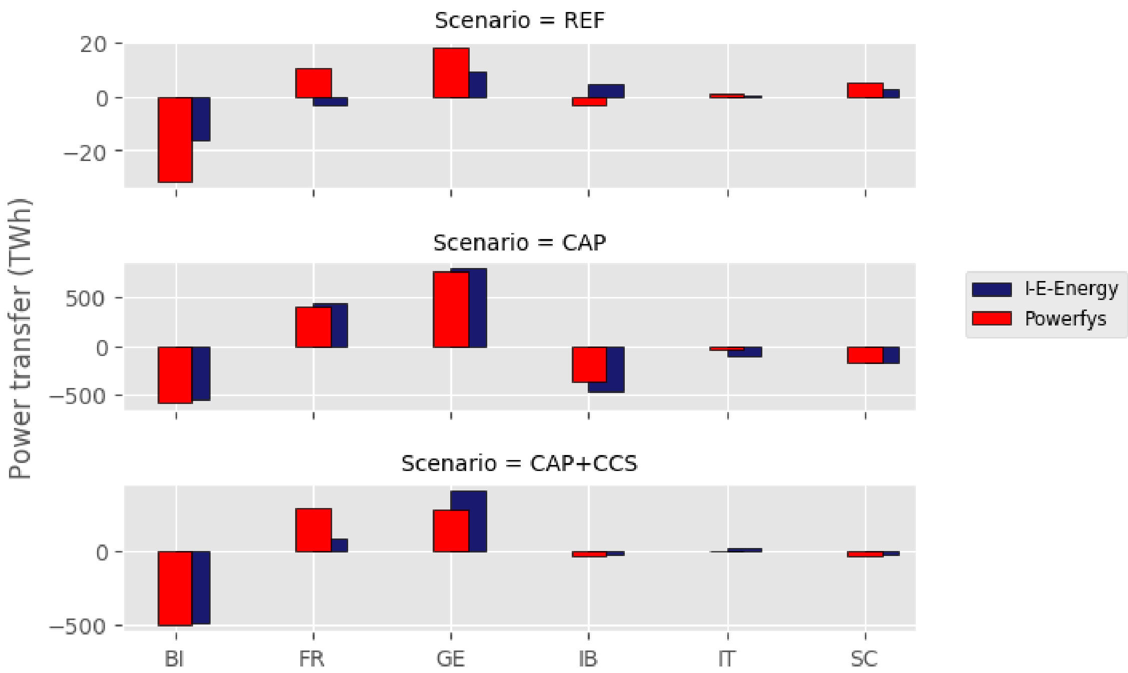

Figure 5.16: *Comparison of Power Transfer between the regions for all three scenarios, comparing Powerfys (red bars) and I-E-Energy (blue bars). From left to right, the bars show the 6 regions considered: BI = British Isles, FR = France, GE = Germany and Benelux, IB = Iberian Peninsula, IT = Italy, Croatia and the Alpine States, SC = Scandinavia. Positive bars mean that the region is a net importer of electricity, the negative bars show that the region is a net exporter.*

With some exceptions, power transfer follows a similar pattern for both the CAP and CAP+CCS scenario. The scenario that shows the most irregularities is the reference scenario. This scenario also has the smallest total power import and export. The irregularities are large in relative numbers, but small on an absolute scale. The relative differences of the reference scenario could be attributed to a certain level of randomness: the main part of the power is generated by unconstrained coal-fired power plants, operating under the same cost regime in all regions. This means that there is no reason to install coal power at a certain location (a reason would be a higher average capacity factor for renewable energy compared to another country).

For scenario CAP, the main differences between Powerfys and I-E-energy are found in the Iberian Peninsula and the British Isles. In I-E-Energy, the Iberian Peninsula has a larger role as power exporting entity than in Powerfys. This is offset by the British Isles that export more power when simulated in Powerfys. Slightly larger differences can be found in scenario CAP+CCS. While the profile of importers and exporters of power are similar, I-E-Energy transfers more power from the central hub Germany, but less from France. The rest of the net power transfer is almost equally distributed over the regions. Figure 5.15 shows that I-E-Energy transfers more power but this does not show in the net power transfer. When the total import and export profile is taken into account, I-E-Energy transports less power.

For large transmission capacities, both models converge to similar power transfer patterns. When more randomness is introduced to the system, this shows in the results: both models find more random solutions. For the reference scenario, the power transfer realised is rather small, therefore inconclusive. As the transmission capacity increases so does the relative similarity between both models.

5.4.3 Storage Charging and Discharging per Region

The total power that is committed to charging and discharging of storage units, is compared for both models. Figure 5.17 the total charging and discharging of all storage units aggregated per region is shown.

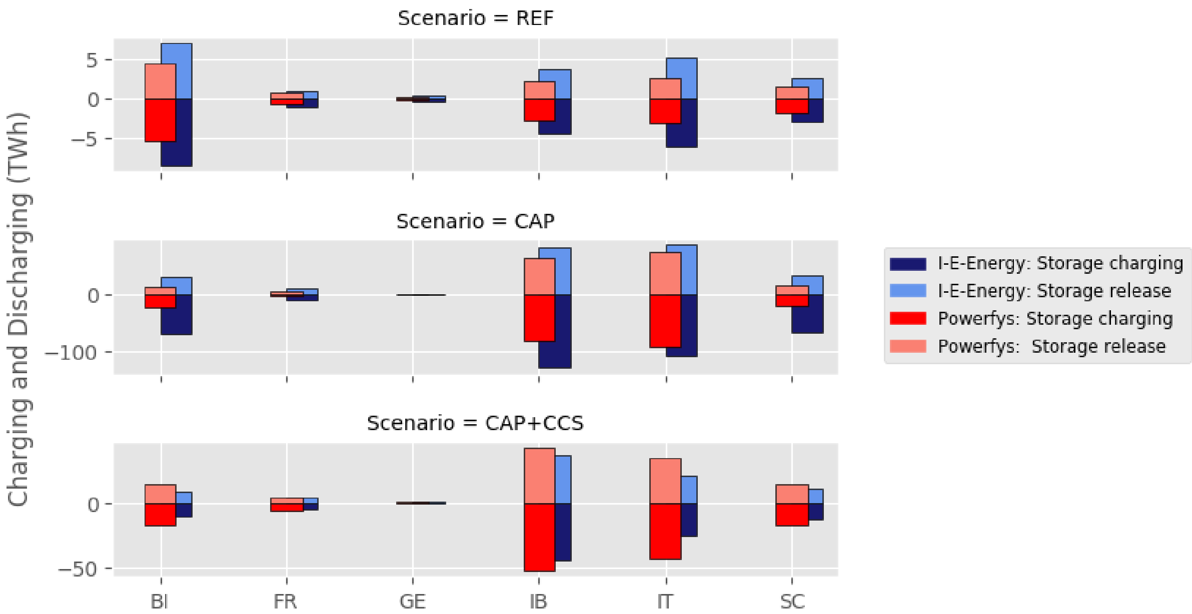

Figure 5.17: *Comparison of Power storage charging and storage discharging for all regions for all three scenarios, comparing Powerfys (red bars) and I-E-Energy (blue bars). From left to right, the clustered bars show the 6 regions considered: BI = British Isles, FR = France, GE = Germany and Benelux, IB = Iberian Peninsula, IT = Italy, Croatia and the Alpine States, SC = Scandinavia.*

Congruent to the installed capacity represented in figure 5.6, the reference scenario has limited storage capacity. Hence, limited power is charged or discharged. I-E-Energy uses more storage capacity in the reference scenario, as well as in the CAp scenario. In the CAP+CCS scenario, slightly more storage charging and discharging is done by Powerfys.

Regarding regional distribution, both models follow similar patterns. This holds for all scenarios. The differences in the region are proportional to the overall difference in storage use (e.g. in the CAp scenario, the British Isles charge and discharge less power with Powerfys, but this is true for all regions).

Validation And Sensitivity

The answer to the question whether the simulation model and its results are correct is assessed through verification and validation (Sargent, 2004). In chapter 3, the model was verified. Validation is the activity of checking the accuracy of the model's results with respect to the real world situation. The question associated with validation is: Did I build the right thing? This chapter further elaborates on the validation process. The results obtained in chapter 5 are evaluated for their credibility in section 6.1. Additionally, a sensitivity analysis is conducted to test the influence of several input parameters on the model outcome, in section 3.5.

6.1 Model Validation

To answer the question: "Did I build the right thing?" a model validation is carried out. Sargent (2004) defined several validation methods, two of which are deemed relevant for this research: historical data evaluation and comparison to other models. The most accurate model validation is to test its ability to reproduce a real-world system, using historical data. However, I-E-Energy simulates a future system. Hence, it is not possible to compare to real-world data. Another possibility is a comparison to other model outcomes, but this decreases the level of accuracy. Therefore, both methods are applied here. By altering the initial parameters to fit current data and by relaxing the emission constraint, a real-world projection is made, validating the model's equations. The model outcome is then compared to real-world ENTSO-E data. Subsequently, the model outcome of the scenario run is compared to other model projections, validating the results of the scenario runs. There are three main elements of the model that need to be validated:

1. The model's ability to determine the levelised cost of electricity;
2. The model's ability to determine the optimal installed capacity;
3. The model's ability to determine the optimal generation mix.

Some simplifications that have been made for this model are significant. Therefore, the outcomes are not expected to be completely similar. To achieve highe accuracy, the model is compared to both real-world data and other models. Additionally, generation mixes are expected to be less accurate than installed capacities, because of accumulating inaccuracies. For example, if I-E-Energy overestimates optimal coal power capacity, more coal power will be installed. If coal generation is overestimated, the effect is amplified by the ability to utilise all previously installed capacity.

6.1.1 Validation of Levelised Cost of Electricity

The system's LCOE should be similar to real-world LCOE when the model is run with current parameters. The system's LCOE projection for 2050 should be similar to other model projections. To represent a run for the current electricity system, the model run is performed with techno-economic parameters for current generation, transmission and storage parameters and fixed transmission capacities. These inputs can be found in B.5. The results are then compared to average estimated wholesale electricity prices for Europe (aleasoft, 2012) and an average of the five leading European spot market prices (DG-Energy, 2012a,b; Energy, 2012), the specific spot market and wholesale prices can be found in appendix C. To validate the 2050 LCOE, two

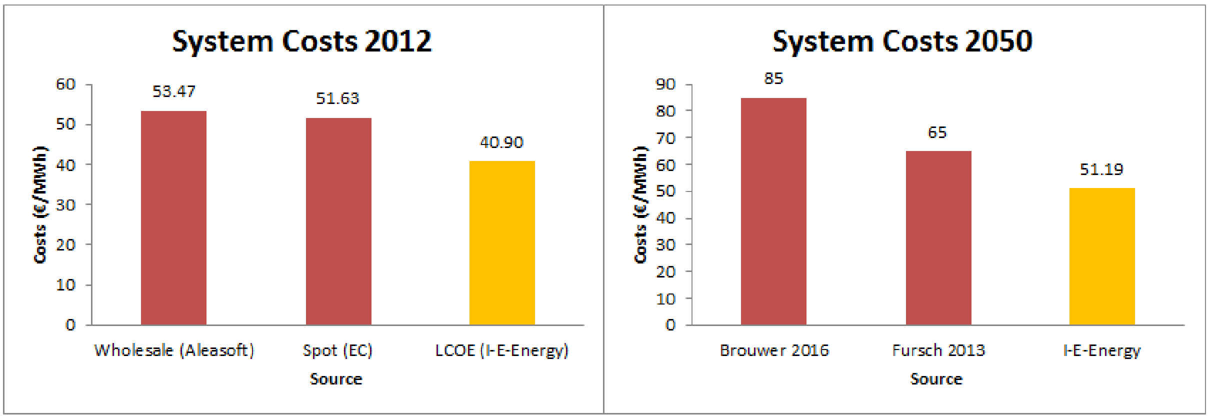

Figure 6.1: *Comparison of LCOE between wholesale and spot market electricity prices and I-E-Energy for 2012 and model projections for 2050. The left bar chart represents LCOE calculated by I-E-Energy and compared to the average wholesale price and average spot market prices for five leading European markets. The right bar chart represents the LCOE calculated by I-E-Energy for 2050, compared to two other studies that consider projections of future electricity systems. Brouwer et al. (2016) considers an 80% renewable electricity system for Western Europe, Fürsch et al. (2013) considers a future electricity system with a* CO_2 *target of 80% below 1990 levels.*

studies are evaluated that reflect this study as closely as possible. Analogous to comparisons to real-world data, the studies yield different results, with different causes, rooted in intra-model differences instead of simplifications of the real world. One study (Brouwer et al., 2016) models the same area (Western Europe), but uses a different modelling approach. The other study (Fürsch et al., 2013), uses a similar model approach that incorporates an investment decision, but considers a pathway starting from the current electricity system.

In both the 2012 and 2050 case, I-E-Energy results in lower system costs than its equivalents. Considering the real world data, there are several reasons why.

This model claims perfect foresight. The model finds a cost-optimal solution based on a known demand, with a known series of renewable energy production potential. It is, therefore, able to optimally use all its installed capacity and does not require any reserve flexibility. Real world systems always need a certain level of reserve capacity in case the demand suddenly becomes higher, or renewable energy produces less power than anticipated on before.

I-E-Energy simplifies technical detail. I-E-Energy models a reduced number of nodes, models a reduced number of technologies and exempts several technical constraints. These simplifications result in a more efficiently used model. The consequences of these technical differences are elaborated on in section 6.1.2, where it can be seen how coal (the cheapest source of electricity) dominates the generation mix. This results in a lower LCOE as well. The use of the copper plate principle also leads to lower costs, since electricity can flow freely within a region. The larger the region, the more optimistic the model becomes.

A green-field model does not take into account inefficiencies caused by government policy, social implications and any lock-in situation from prior power sector investments. I-E-Energy starts from a situation where there is no existing power sector, and everything can be built from scratch (hence the "green-field" analogy). Operating from the assumption that a single planner can determine everything, the optimal solution is the most efficient technology mix that can fulfil the electricity demand and respect the technical constraints. In real life, prior situations greatly affect the composition and therefore the system costs of the electricity system. Also, government policy changes over time and society sometimes protests certain changes (for example a bird watching organisation that delays construction of wind parks, causing inflated costs or reduced output). Lastly, the implication of a single planner that decides on the whole construction process of the energy system greatly improves efficiency, leading to lower system costs.

The 2050 projection also underestimates the system costs, compared to other models projections. This is not the result of the reasons mentioned before (the other models operate under similar assumptions) but the result of intra-model differences.
Both other models incorporate CO_2 prices in their system costs prediction. These both result in higher total system costs. I-E-Energy only incorporates an emission cap. The CO_2 that is emitted until this cap is reached results in a higher system costs for both Brouwer et al. and Fürsch et al..

Brouwer et al. (2016) pre-defines the installed capacity, which rules out an efficient solution through altering the composition of generation capacity. (Fürsch et al., 2013) does allow capacity changes but considers a pathway starting from a current fixed configuration. Both studies impose more restrictions than I-E-Energy, thereby increasing the LCOE.

6.1.2 Validation of Installed Generation Capacity

To further investigate differences between the installed generation capacity that is determined by I-E-Energy and its comparison to real-world data for 2012 and other model projections for 2050, the installed generation capacity is compared. Since the model outcome of the comparable study does not consider the same area, results are compared on a relative basis instead of absolute numbers. The previous section elaborated on the total system costs, this section further analyses how these cost differences are reflected in the determined generation capacity. Some of the differences observed are obvious, such as the absence of nuclear power in I-E-Energy. Nuclear power was not included as an input parameter. Therefore, close attention was paid to the ratio between baseload plants (such as coal, nuclear, hydro-run-of-river, lignite) and peak plants (gas, gas-CCS). Another aspect that was evaluated is the ratio between conventional (with and without CCS) and renewable energy technologies. Furthermore, the amount of installed PV capacity was compared to the installed wind power capacity, elaborating on both real-world data and the model comparison. Figure 6.2 shows the results.

I-E-Energy underestimates peak power requirements When looking at the comparison of real data versus I-E-Energy for 2012 parameters, the ramifications of simplification become more clear. The run has been performed unconstrained, which means that the cheapest technology will be dominant. The large variety of real world installed capacity versus the limited amount of technologies incorporated in I-E-Energy induces a large overestimation of coal-fired power. This overestimate is significantly reduced when the comparison is made based on base-load generators compared to peak plants. However, its is still clear that I-E-Energy underestimates peak power generation. For both the current (2012) run and the future (2050) projection, this trend is seen. The explanation is twofold:

- The regional setup favours base plants: countries that need to balance their load, call upon gas-fired power plants (low fixed, high variable costs) to cover for peaks in energy demand that occur only a small amount of hours per year. If several countries are combined into one node, a larger part of the hourly load can be fulfilled by a base-load (coal)

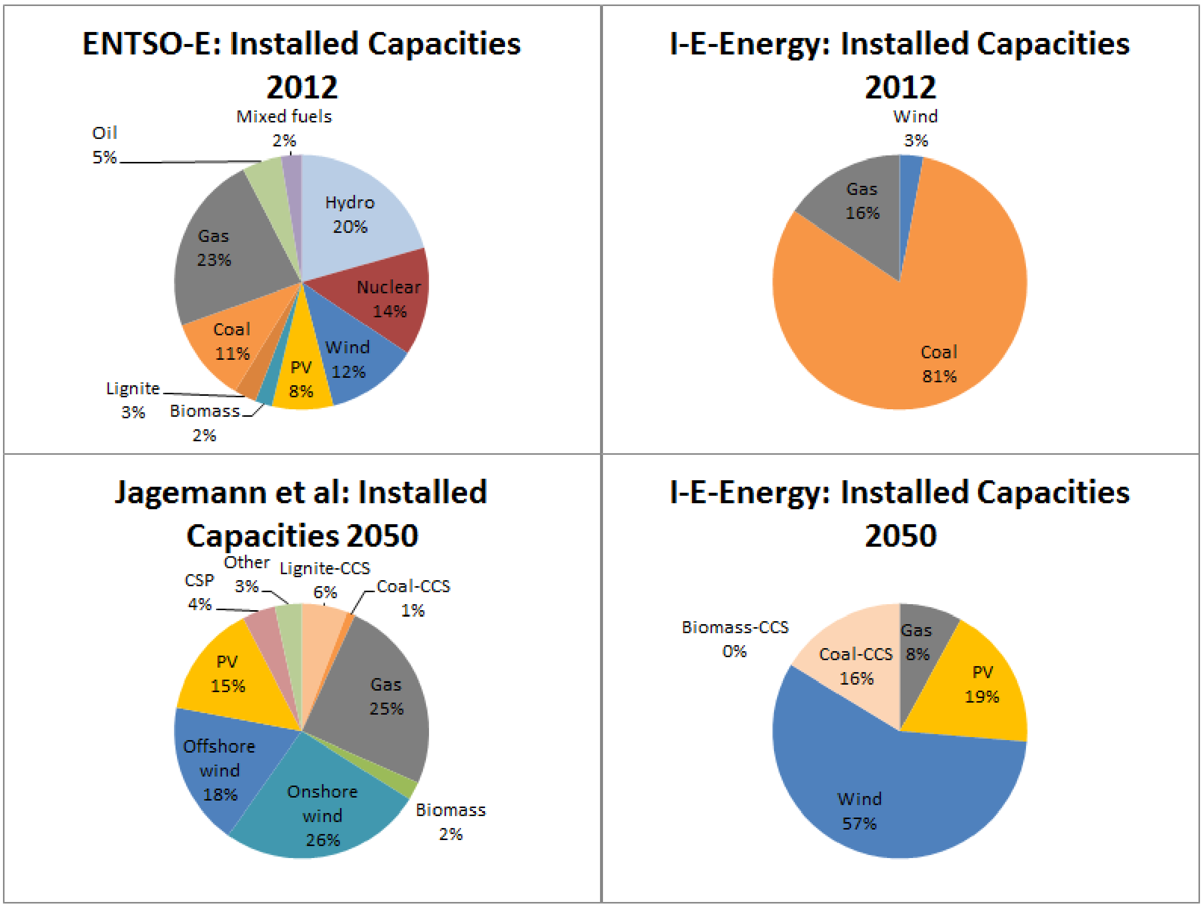

Figure 6.2: *Comparison of installed Generation capacity between real-world ENTSO-E data and I-E-Energy for 2012 and a comparison of projections for 2050. The upper left pie chart represents the installed capacity for 2012 based on ENTSO-E (2015), the lower left pie chart represents the installed capacity found by Jägemann et al. (2013). The upper right and lower right pie chart represent the installed capacity found by I-E-Energy for 2012 and 2050, respectively.*

plant. Hence, the copper plate renders the role of power generation as peak plants partly obsolete. This explains the relatively increased preference for coal over gas in the current electricity system.

- The future electricity system allows for an unconstrained flow of power between regions. On top of the copper plate effect, the remaining peak power of all regions combined can be supplied by a plant in one country. The peak demand suddenly becomes more regular and higher investments become more profitable. As a result, a larger amount of coal-fired power is installed.

Under current economic parameters, I-E-Energy underestimates the total amount of installed renewable energy capacity. This is purely based on investment costs for renewable power. The current emission levels do not restrict the power system enough to force the building of renewable energy capacity. Europe's current fleet of renewable energy power is built mostly on subsidies and renewable energy capacity requirements, which are not taken into account in this model. This is one example of the point made in subsection 6.1.1 on government policy. When the future installed capacity is considered, the amount of renewable energy installed is higher than in the comparable study by Jägemann et al. (2013). The future installed capacity shows a higher degree of similarity with this model. The renewable energy capacity is still slightly overestimated, which can be explained by the stricter CO_2 target set in this research.

Relevant only to the future model prediction, the share of coal with CCS built with I-E-Energy is significantly larger than was constructed by Jägemann et al.. Again, this is slightly balanced when the comparison is made based on base-load instead of a single technology (lignite with CCS would be substituted by coal with CCS). In part, the gas-fired power is replaced by renewable energy as a consequence of stricter CO_2 targets. Additionally, the previously mentioned lower node resolution favours coal over gas, which constitutes, in this case, to favour coal with CCS over gas without CCS (coal without CCS is omitted in both cases because of its high emission levels).

6.1.3 Validation of Generation Mix

The last validation considers the total amount of electricity generated by I-E-Energy, compared to the generation mix in the real world (2012) and a projection using the same model by Jägemann et al.. Results show patterns similar to subsection 6.1.2 but are amplified: the scenario with current parameters is almost completely dominated by coal-fired generation. This is partly a result of a recurring error, amplified through the model setup: I-E-Energy considers a green field situation and constructs large amounts of coal-fired power generation capacity, gas-fired generation is only needed in rare situations. Subsequently, the generation mix is overestimated for the same reasons as the installed generation capacity: the model setup (zonal grid, transmission network) favours coal-fired generation in a situation where construction of coal-fired power plants is already favoured. As a result, generation by coal becomes more dominant.
This effect does not occur to such an extent in the future generation mix. The CO_2 target forces the installed capacity and generation mix into a more balanced mix. For the same reasons as mentioned before, coal-fired generation is favoured over gas, but the overall picture shows a fairly similar generation mix.

Considering all three aspects, I-E-Energy provides an accurate picture of the future electricity system, suitable for the experiments that have been conducted with it. The gravest concern (the gross overestimation of coal-fired power) is offset through the CO_2 target set in the future scenario. The conclusion that can be drawn is that I-E-Energy is validated.

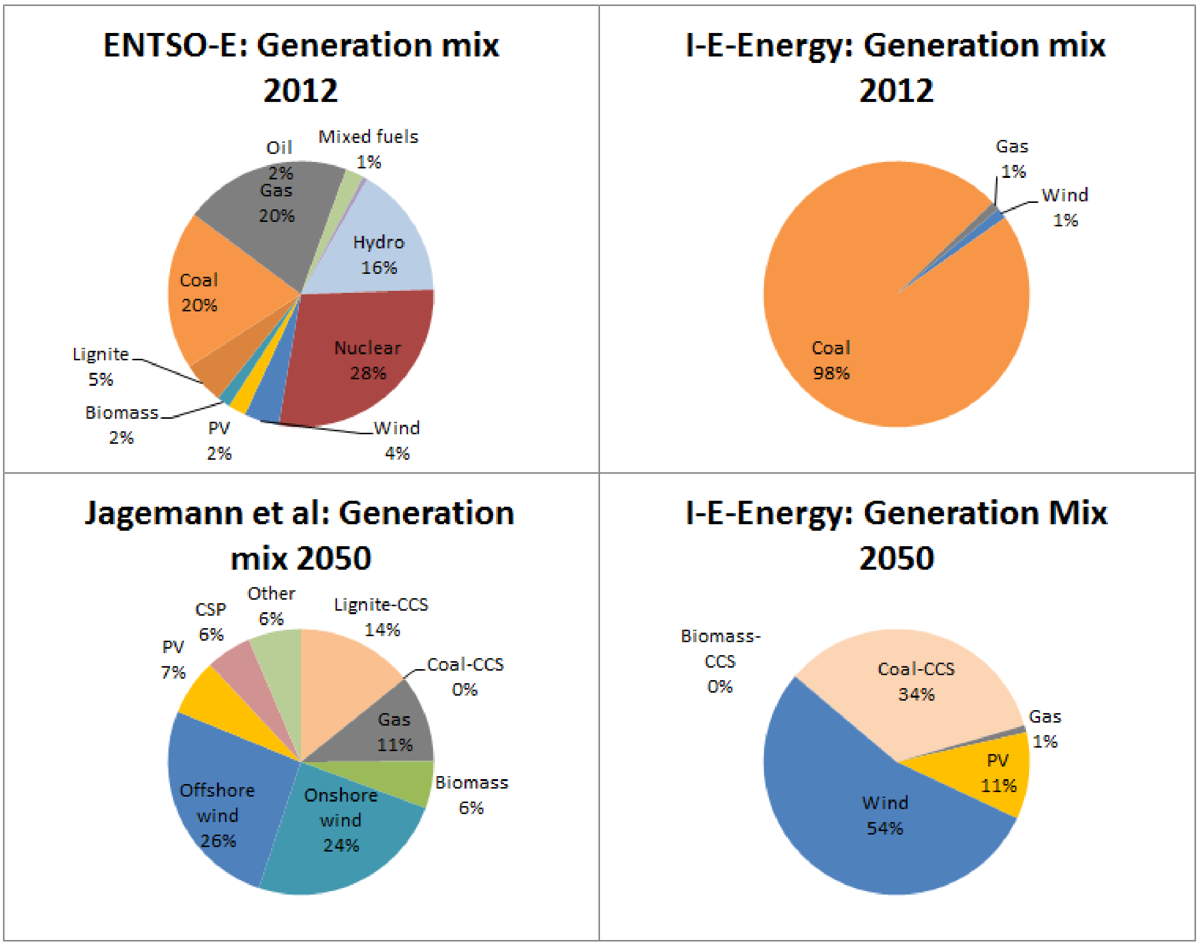

Figure 6.3: *Comparison of the generation mix between real world ENTSO-E data and I-E-Energy for 2012 and a comparison of projections for 2050. The upper left pie chart represents the generation mix for 2012 based on ENTSO-E (2015), the lower left pie chart represents the installed capacity found by Jägemann et al. (2013) for 2050. The upper right and lower right pie chart represent the generation mix found by I-E-Energy, for 2012 and 2050 respectively.*

Parameter	Technologies	Range
CAPEX	Renewable energy, conventional, CCS and storage	from -50% to +50%, steps of 25%
OPEX	Conventional, CCS	from -50% to +50%, steps of 25%
CO_2 emission	Conventional, CCS	from -50% to +50%, steps of 25%

Table 6.1: *The parameters that were varied for the Sensitivity analysis. Renewable energy = Wind and Solar PV, Conventional = Coal, gas and biomass, CCS = all techs with CCS, storage = PHS, H2 and flow batteries*

6.2 Sensitivity Analysis

The techno-economic parameters that serve as input parameters for this research are based on parameters found in several literary sources. Especially for future projections, it is hard to determine accurate costs. As a result, large differences between different studies are found. Additionally, several test runs showed the models dependence on those input parameters. To gain insight into the impact of these highly disputed input parameters on the model outcome, a sensitivity analysis was conducted. The setup and varied parameters are explained in subsection 6.2.1. The results are presented in subsection 6.2.2, subsection 6.2.3 and subsection 6.2.4.

6.2.1 Setup of Sensitivity analysis

The costs of solar PV and wind energy have decreased further and faster than many had anticipated on (REN21, 2016). The chances are that future costs predictions for these two technologies are too conservative. Furthermore, both capital costs and operational costs for carbon capture and storage technologies have been subjected to debate. For example, a comparative literature study on coal-fired power plants with CCS show capital expenditures ranging from 1615 €/kWh to 2950 €/kWh (Lohwasser and Madlener, 2012). Some studies take into account the storage and transport of CO_2, whereas others do not. This can affect the model impact significantly. A study by Schröder et al. (2013) shows how these costs can double the variable costs. Gough and Upham (2011) incorporates these costs as fixed operation and maintenance costs, but the choice between these two approaches has far-reaching implications for the model results. The novelty of CCS not only causes cost uncertainty but also regarding the efficiency of CO_2 capturing. These debated issues are treated in the sensitivity analysis. Table 6.1 gives an overview of the parameters that are tested. Some variables (such as CCS and renewable energy) are grouped. The effects mainly concern the relation between these groups, rather than individual effects. All parameters were only tested in the scenario with the CO_2 constraint implemented and the possibility to install CCS: the main reason for this analysis is to understand the dynamics between CCS and renewable energy. The scenarios are named TechnologyX_sign,deviation (e.g. RES_min50: technology = "renewable energy", sign = minus, deviation = 50%).

6.2.2 Sensitivity to Investment Costs

The sensitivity to investments for technologies is analysed for three main categories: the deviation from system LCOE (figure 6.4), the installed capacity changes (figure 6.5) and total electricity generation changes (figure 6.6). The levelized cost of electricity behaves as expected when subjected to capex variations: lower investment costs induce lower LCOE, and higher investment costs result in higher LCOE's. The highest spread can be found for renewable energy, followed by carbon capture storage. Electricity storage and conventional generation show similar results. This corresponds to their capacity share in the energy system configuration. Figure

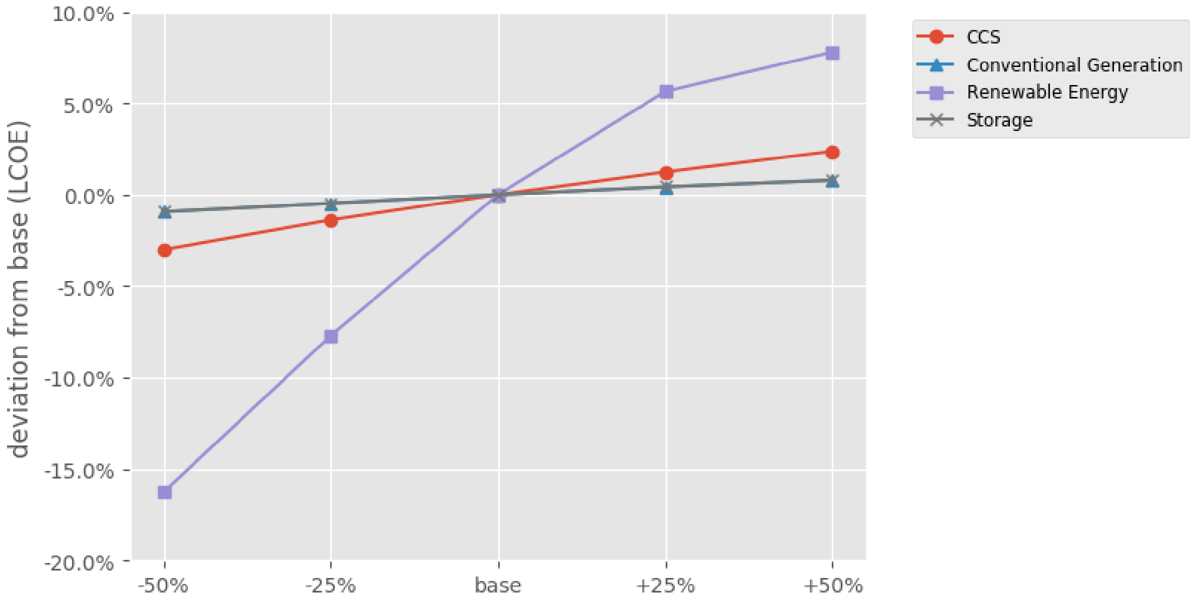

Figure 6.4: *The results of the Sensitivity analysis: Sensitivity of LCOE as a result of changing investment costs, in percentage deviation from the system LCOE. The y-values represent the deviation from the original run (Scenario with emission cap and CCS implemented), the x-values the percentage variation in capital expenditures.*

6.5 shows how changing investment costs has various effects on the capacities of the electricity system. As investment in specific technologies becomes cheaper, their capacity shares increase. Generation profiles (depicted in figure 6.6) behave according to the same patterns as installed capacities. For all scenarios, there is a clear dominance of one technology CCS, with the exception of cheaper renewable energy.

6.2.3 Sensitivity to Operational Costs

Analogous to subsection 6.2.2, the deviation of LCOE, installed capacities and generation mix from the original scenario as a result of variable operational costs changes is analysed. The absence of variable operational costs for renewable energy and storage made rendered simulation runs for these two technology groups obsolete.

Changing CCS operational costs has a significant impact on system LCOE. Especially when lowering the costs, the total system costs drop by 30%. Increasing the operational costs results in an increase of 7% as well. This effect is reflected in the capacity share. It shows that renewable energy sources are almost completely replaced by coal in combination with CCS. It must be stated that this is only possible by increasing the share of biomass with CCS and its negative emissions. On the other hand, a slight increase in operational expenditures for CCS results in a significant increase in renewable energy, transmission and storage capacity, compared to the reference scenario. This effect is reflected in the generation mix, where the CO_2 emission increase of coal with CCS in the low-cost scenarios is offset by increased generation off biomass with CCS.

Operational cost changes of conventional generation technologies do not influence the LCOE as much as CCS. The spread resulting from a 50% decrease is around 2%, and a 50% increase

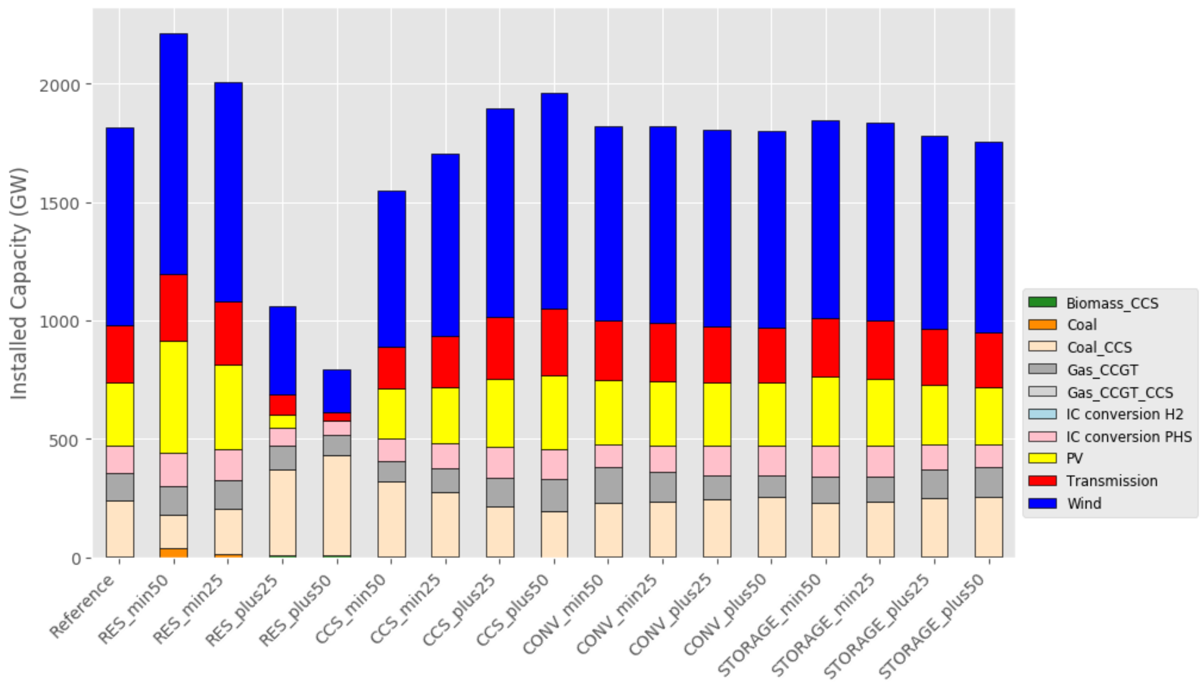

Figure 6.5: *The results of the Sensitivity analysis: Sensitivity of Installed Capacity as a result of changing investment costs, in GW. The first scenario represents the original run (Scenario with emission cap and CCS implemented), the*

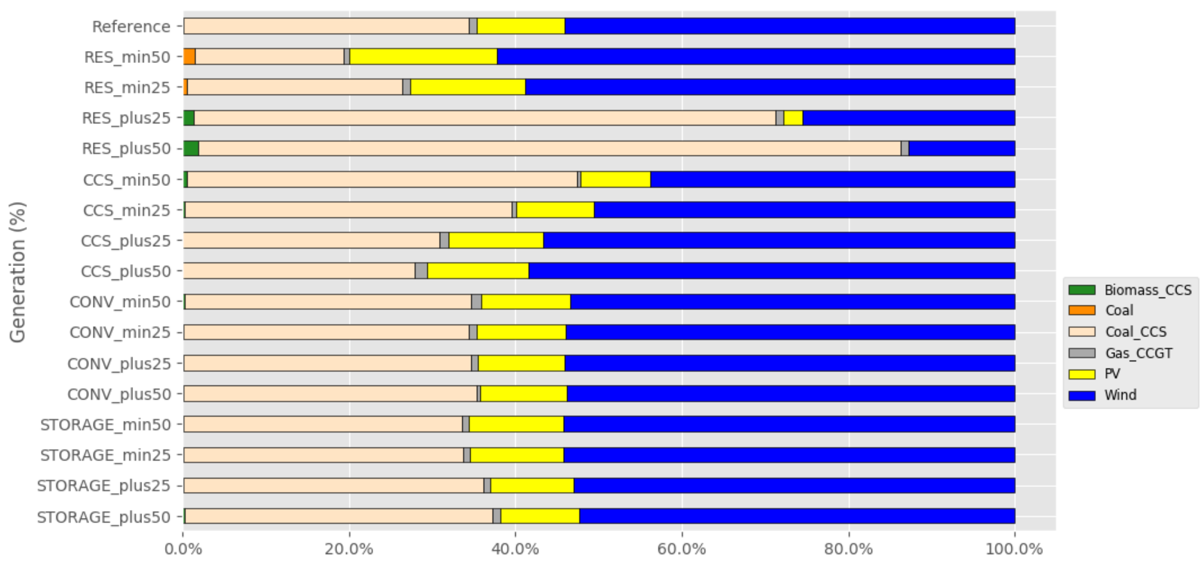

Figure 6.6: *The results of the Sensitivity analysis: Sensitivity of total generation mix to changing investment costs. The horizontal bars each represent a scenario, as a percentage.*

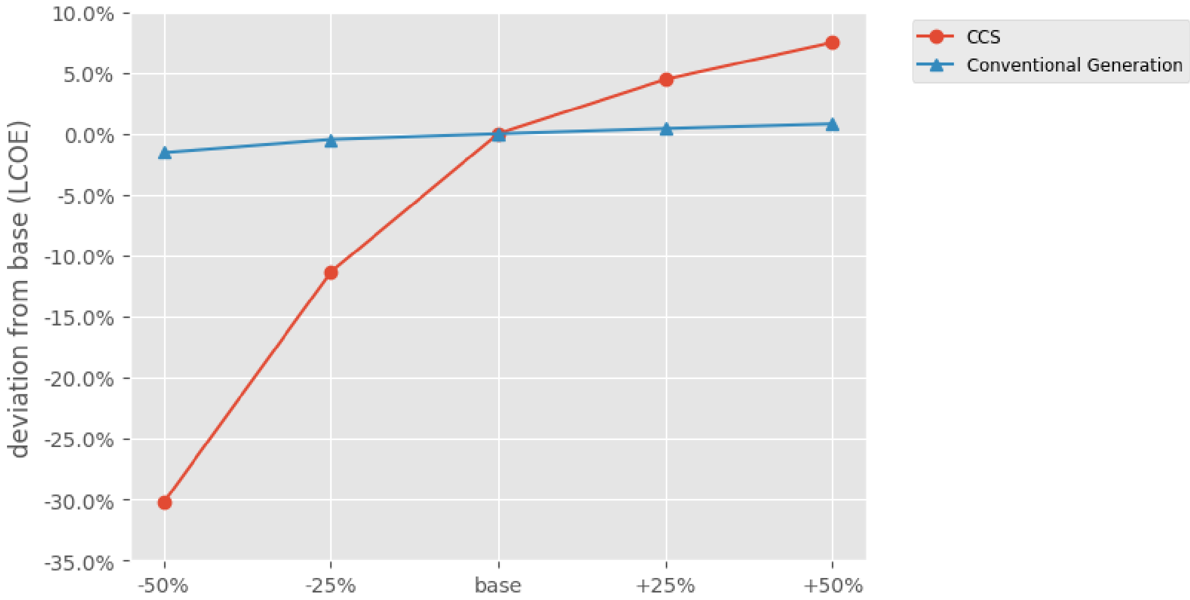

Figure 6.7: *The results of the Sensitivity analysis: Sensitivity of LCOE as a result of changing investment costs, in percentage deviation from the system LCOE. The y values represent the deviation from the original run (Scenario with emission cap and CCS implemented), the x values the percentage variation in capital expenditures.*

results in a less than 1% increase. The capacity shares also remain largely unaffected by these changes. The only significant effect that can be observed here is a shift from coal with CCS towards gas when operational expenditures are lowered by 50%. Increasing this gas share in a strict emission cap regime is made possible by increased generation of biomass with CCS, which can be observed from the generation mix.

6.2.4 Sensitivity to CO_2 Emission Parameters

The last parameters that were varied are CO_2 emission parameters. As for the cost parameters, the CO_2 emission parameters for carbon capture and storage are highly uncertain. Therefore, the emission parameters for coal with CCS, gas with CCS and biomass with CCS are varied from -50% to +50%.

Gas in combination with CCS does not play a role in the future electricity system. Increasing or decreasing the CO_2 parameter did not change that model outcome. Biomass in combination with CCS only slightly affects the system LCOE, which becomes less than 0.25% lower as a result of decreasing the CO_2 emission. The largest change can be found for coal in combination with CO_2. However, a 50% change results in a less than 1% change in LCOE, so the effect is marginal.

6.2.5 Discussion of Sensitivity analysis

The variation of capital expenditures, ranging from -50% to + 50%, shows lower variation in LCOE (less than 12% max variation). This means that by changing the system configuration, the model is able to compensate for higher investment costs of specific technologies (or groups of technologies). In all three sensitivity analyses, this holds up. The largest relative impact that can be observed is by altering the operational costs of carbon capture and storage. Furthermore, the results show a negative correlation between renewable energy investment cost and the total

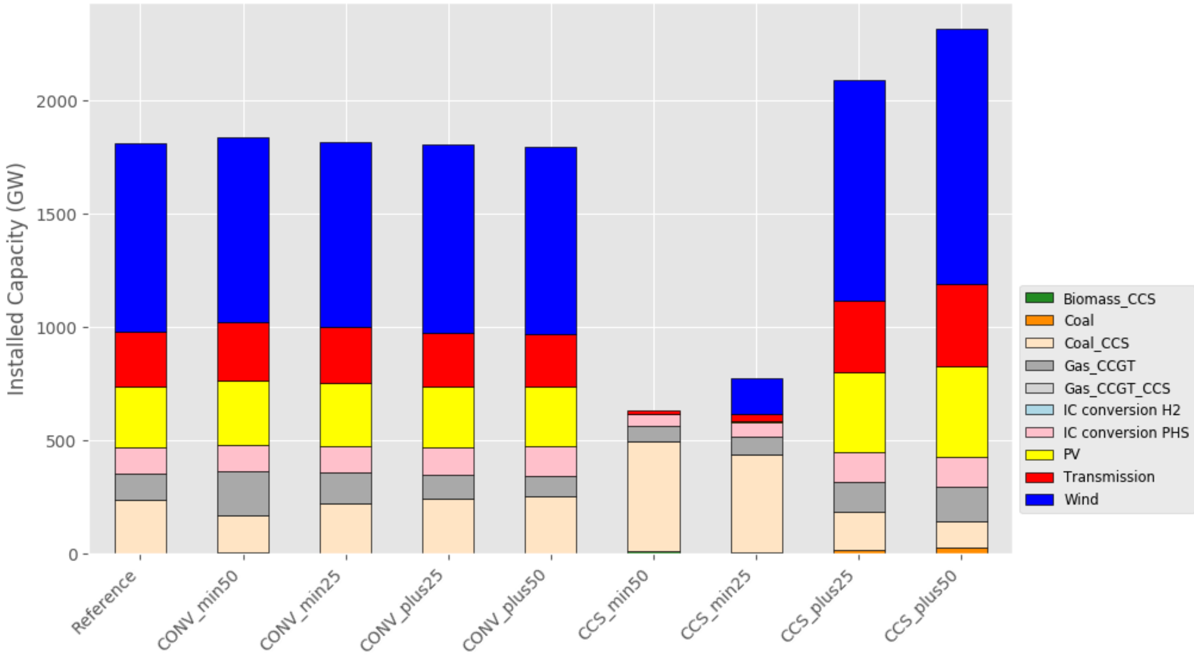

Figure 6.8: *The results of the Sensitivity analysis: Sensitivity of Installed Capacity as a result of changing investment costs, in GW. From left to right: the first scenario represents the original run (Scenario with emission cap and CCS implemented), the next 8 are the results of varying OPEX of conventional generation (coal, gas, biomass) by -50% to +50% and OPEX of CCS technologies (coal with CCS, gas with CCS and biomass with CCS, respectively.*

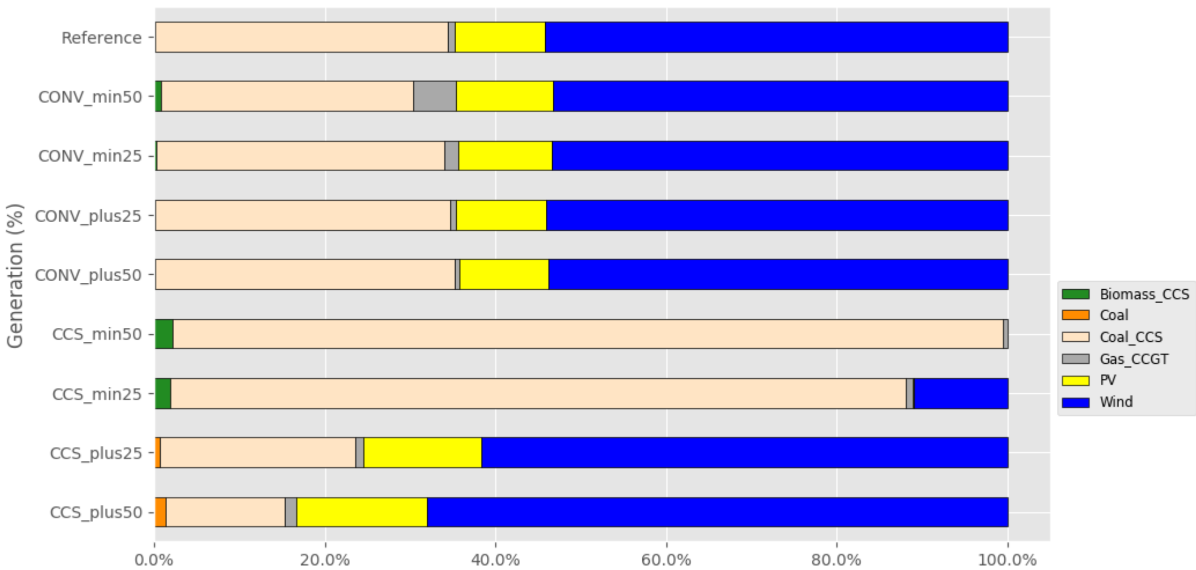

Figure 6.9: *The results of the Sensitivity analysis: Sensitivity of the generation mix as a result of changing operational costs, in percentage of total generation. From top to bottom: the first scenario represents the original run (Scenario with emission cap and CCS implemented), the next 8 are the results of varying OPEX of conventional generation (coal, gas, biomass) by -50% to +50% and OPEX of CCS technologies (coal with CCS, gas with CCS and biomass with CCS, respectively.*

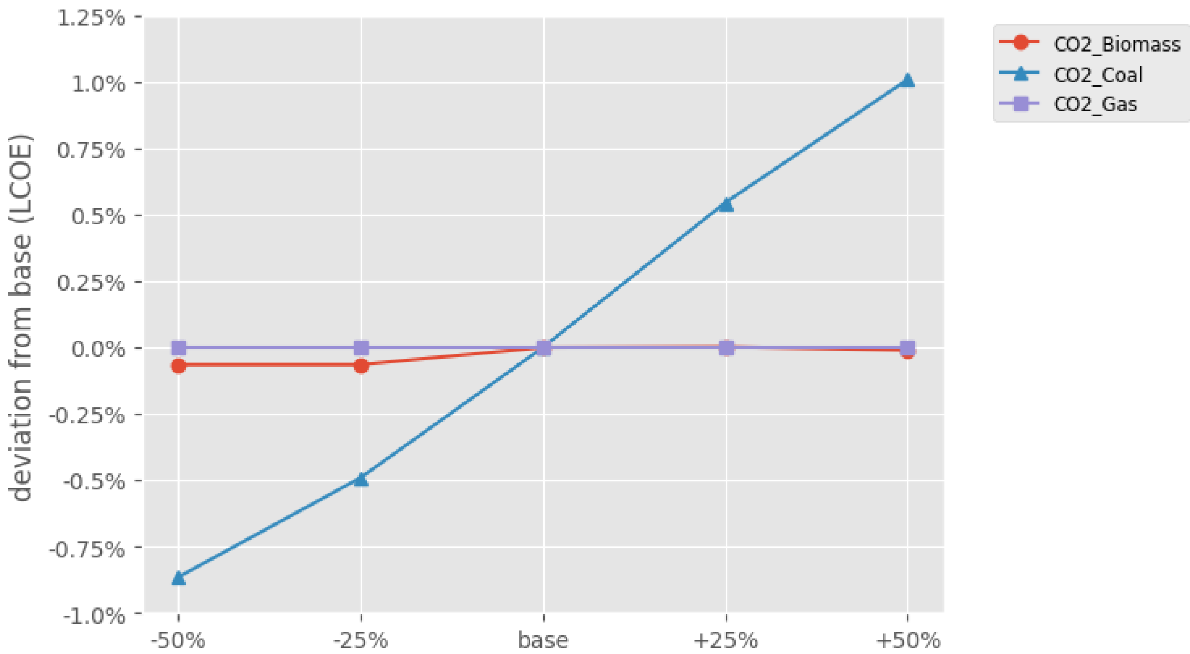

Figure 6.10: *The results of the Sensitivity analysis: Sensitivity of LCOE as a result of changing CO_2 emission parameters, in percentage deviation from the system LCOE. The y values represent the deviation from the original run (Scenario with emission cap and CCS implemented), the x values the percentage variation in CO_2 emission.*

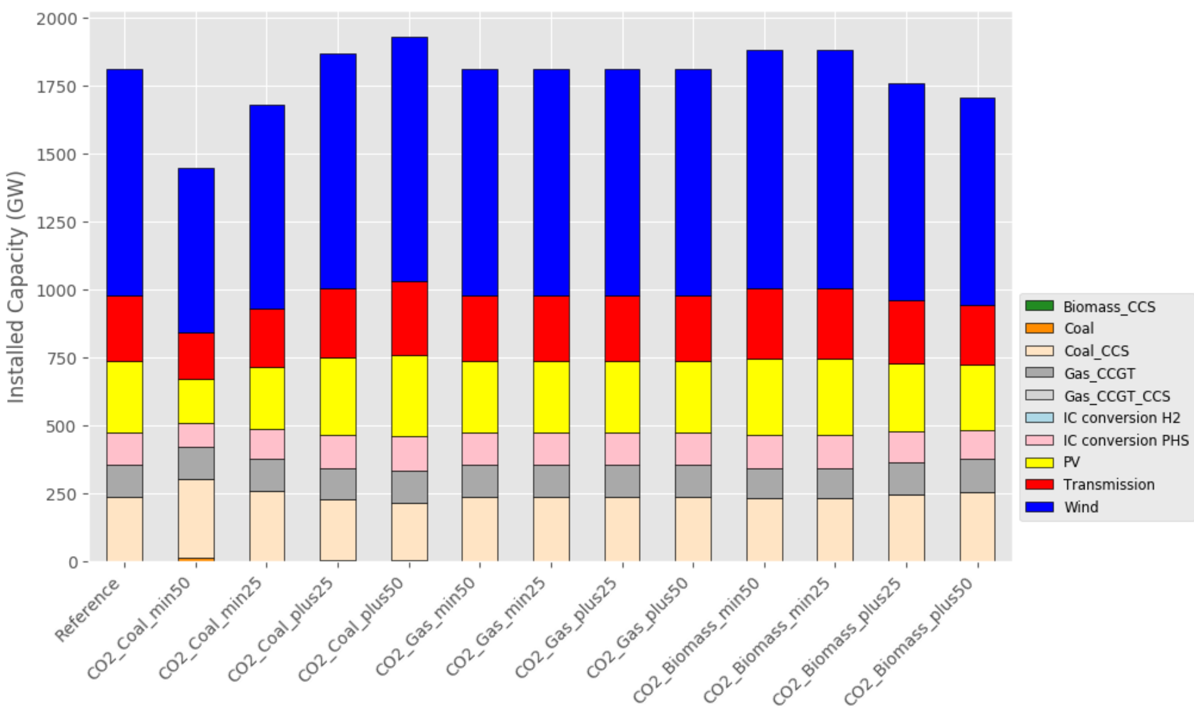

Figure 6.11: *The results of the Sensitivity analysis: Sensitivity of Installed Capacity as a result of changing CO_2 emission parameters, in GW. From left to right: the first scenario represents the original run (Scenario with emission cap and CCS implemented), the nexts scenarios are the result of varying CO_2 parameters for coal, gas and biomass (all with CCS) by -50% to +50%, respectively.*

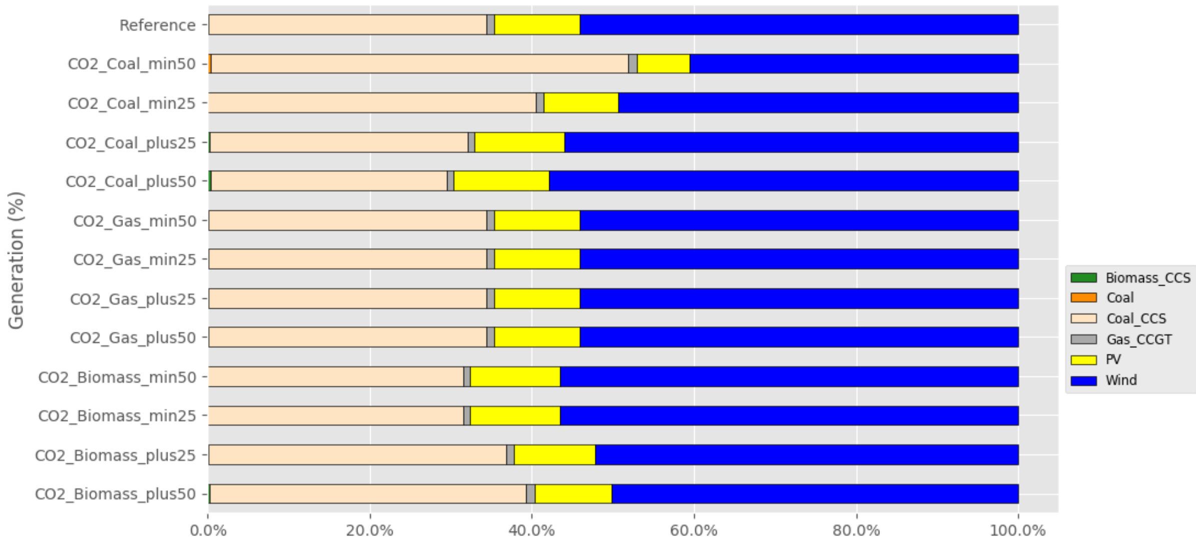

Figure 6.12: *The results of the Sensitivity analysis: Sensitivity of the generation mix as a result of changing CO_2 emission parameters, in percentage of total generation. From top to bottom: the first scenario represents the original run (Scenario with emission cap and CCS implemented), the next scenarios are the result of varying CO_2 parameters for coal, gas and biomass (all with CCS) by -50% to +50%, respectively.*

installed capacity: cheaper renewable energy leads to larger installed capacities. The largest system changes are achieved by either increasing the investment costs for renewable energy, or decreasing the operational costs of CCS. These two technologies function as substitutes. Additionally, renewable energy capacity is accompanied by transmission and storage capacity. Availability of cheap CCS technologies render transmission obsolete.

Discussion

A model is always a simplification of a real-world situation. A model can therefore never be a 100% accurate. Throughout this research, numerous modelling choices have been made, based on assumptions and problems have been simplified, reducing the scale into a workable modelling problem. This chapter aims to provide more insight into the consequences of those decisions and the shortcomings associated with it. Section 7.1 discusses the implications of this research in the larger context. Section 7.2 discusses both models, section 7.3 discusses the input data.

7.1 Social Economic and Environmental Implications

In the larger context, a techno-economic research is not all-encompassing. Not surprisingly, any research should have a well-defined scope, inevitably excluding sectors, actors and factors of influence. It is important to place the results of this research in the larger context and reflect on the political, economic and environmental implications that the proposed solution to the research questions might have.

A cost-optimal solution does not take into account regional or country-specific interests. For example, a significant amount of installed capacity for wind and solar PV is placed in the Iberian Peninsula, but also on the British Isles. At certain periods, surrounding countries become dependent on these countries for their energy supply. Recent developments in the current political landscape in Europe, such as the Brexit, are causes for concern and distrust between nations of the European Union. With disintegrating political trust, policy makers might hesitate to outsource their control over their energy generation supply. Furthermore, grid stability is not considered equally important in every country. For example, the Dutch grid is considered one of the most reliable in the world. Amongst other reasons, it is the result of large infrastructure investments and careful monitoring. If energy supply were to be outsourced, grid stability and security of supply would be as well. Both for political and technical reasons, some countries might have their reservations about integrating the European grid to the extent that the optimal solution proposes.

This model minimises system costs without taking into account market implications. However, our current electricity market is one of the main reasons for the stagnating growth in renewable energy capacity. Electricity is sold in power exchanges through a daily auction, which causes energy suppliers to sell their energy at marginal costs. Renewable energy sources have zero marginal costs, which causes the overall price of electricity to drop. This leads to increased price volatility. Renewable energy sources require significant investments, which require a stable investment climate to estimate the profit that can be made. In short, an increase in renewable energy capacity leads to an unfavourable investment climate for new renewable energy capacity. These market effects are not taken into account in this study, but could change the whole configuration of the power system.

As stated earlier, this model operates from a green-field perspective. This means that the energy system is pretended to be non-existent and everything can be installed at once. As stated in section 2.1, the current electricity system is the result of an environment that evolved over multiple decades with lock-in situations, sunk costs and entangled institutions. The reliability of any such models should be questioned. In real life, the energy system changes are incremental, adding a little bit of low-carbon technologies to an existing power system. When the current situation is taken into account, the results might differ. For example, it might turn out to be cheaper, in the long run, to retrofit existing natural gas or coal plants with post-combustion CO_2-capture options.

I-E-Energy operates on the assumption that a single planner is able to determine all elements of the electricity system. The cost-optimal solution is only reached if all actors in the system work towards the same goal. The more power is in the hands of a single willing entity (e.g. a government), the easier such a transition can be realised. In contrast, the European power sector has been liberalised through a series of directives from the European Union, distributing control and distribute over may actors. This makes realising a cost-optimal solution even harder.

From an Industrial Ecologist's perspective, the results should be placed in a larger context as well. There are certain definite shortcomings to the model assumptions that need to be reflected on. Industrial Ecology takes pride in its systems approach and life cycle thinking, taking into account the total impact of a certain product, from its origin to its demolition. From this perspective, large amounts of installed generation capacity (such as renewable energy capacity) might have larger effects on the environment than the effectsincorporated in this research.

Another argument can be made against the use of carbon capture and storage. One might ask himself the question, is storing large amounts of carbon dioxide underground responsible? From a life-cycle perspective, storing CO_2 underground displaces the current problem to future generations. Furthermore, the places that exist to store CO_2 are finite as well, which makes this technology into another temporary solution. Industrial Ecology aims to mimic ecosystems and close the material or energy cycle permanently, instead of looking for ad-hoc solutions that create future problems.

To conclude, there are technical, political, economic and environmental considerations that come into play when the model outcome is placed in the larger context. This confirms the theory in section 2.1.3, which states that the electricity system is a socio-technical system that should only be viewed in context with its environment. The cost-optimal solution to a power system that abides by the Paris agreements is completely different from our current system. To implement this solution, major technical changes are required, such as the integration of the grid and full-scale deployment of renewable energy sources. Lack of economic incentives complicate these transitions. Perhaps the only way to successfully pull of one of the largest systems transitions is through government control on a European scale. And even then, the environmental impacts that are ignored in this research might lead to a failure to reach the climate agreements.

The combinations of these factors influence the model outcome of this study heavily. Nevertheless, the results are still useful as knowledge of what the optimal system should look like. It can serve as a desirable future to strive for and to provide guidance onwhether policy choices will approach the cost-optimal solution. Interpreted as such, this research provides sufficiently relevant value for actors in the power sector.

7.2 Discussion of Model design

In an ideal world, modelling the energy system would include all nodes of the real transmission system, all possible technologies, all constraints and a per second time resolution for the past 50 years and the 100 to come. Unfortunately, this would require enormous computational power and enormous brain capacity to run such a model and interpret its results. Consequently, there is a trade-off to be made between temporal, spatial and technical resolution and computation time. To solve this issue in this particular case, two models are deployed: I-E-Energy, which sacrifices technical detail for a high temporal resolution and Powerfys, which sacrifices temporal resolution for technical detail. By integrating the two models, an attempt is made to provide a complete image with a high technical detail and a high temporal resolution. However, the models are only compared, the outcome is not an integral solution. The technical constraints from Powerfys are not taken into account to determine installed capacity: its preference for gas-fired power could have impacted the configuration of installed capacity. However, this succession of models is as accurate as possible within the confinements of this research.

The linear cost optimisation by I-E-Energy has the advantage of being able to model both investment decisions and operational costs over a long period of time. This is advantageous to accurately model renewable energy generation capacity. Investment decisions for generation capacity in a system where demand is always satisfied, are determined by the maximum amount of power that the separate units are going to provide at a certain time. Small fluctuations in wind and solar energy have some impact on hourly loads of thermal generation units, but large discrepancies are caused by longer periods of extreme weather conditions. Ecofys has dubbed the phrase "windless winter weeks", referring to a longer period with low solar radiation, where large parts of Europe are without wind. It is during those times, that maximum capacities expanded to fulfil satisfy demand on an hourly basis. It is during those times that system costs are increased. The advantage of the linear optimisation model is the possibility to model large consecutive hourly time series, through which those windless winter weeks are accounted for.

The disadvantage is two-fold. First, generation units are confined to large per-region aggregated units, since the available number of variables are consumed by a multiplication of generation technologies, hours and regions. Secondly, technical constraints such as ramping, minimum generation, on/off-times and startup - and shutdown costs are ignored: the level of detail is sacrificed to enable modelling of longer time periods. The reason for this necessary cutdown can be found in complicating constraints and variables. An investment decision is based on information for the whole year. Additionally, the energy level of the storage units is determined based on the energy level of the previous hour. As such, the optimisation problem is connected for all hours of the year. The problem to optimise grows quickly if longer time periods are modelled. Therefore, the number of regions and technical details need to be kept to a minimum for I-E-Energy to still find a solution.

Powerfys also solves the optimisation problem on an hourly basis. However, this model considers a maximum of 36 hours at once. The dispatch is solved for a whole year but on a step by step basis. The model does take a considerable amount of time, but the computational power required is moderate. The disadvantages are the exact opposite of I-E-Energy: the inability to model investment decisions and seasonal storage.

7.3 Discussion of Input Data

The demand and renewable energy production data for this model, which were based on country-wide averages, are a gross simplification of the real world situation. On top of this, the countrywide averages are averaged to region-wide demand and renewable energy production data. Both these simplifications positively affect modelling time, but sacrifice on accuracy. Most model inaccuracies can be attributed to this "Copperplate" principle.

Electricity consumption is a quantifiable unit, which is carefully monitored by the European network of Transmission system operators. The aggregated demand for regions is represented by the sum of the hourly load all countries within that region. This input parameter can, therefore, be considered accurate. However, future demand predictions are inherently uncertain. The assumption that demand is increased by 40% in 2040 only affects the magnitude of demand, but not the daily and seasonal patterns. The phase shift from gas to heat pumps probably adds more demand at peak hours. For electric charging, this can be flattened using controlled charging, but the technology adoption of this is still uncertain. To properly model the future demand, possible changes in peaks and valleys should be taken into account as well.

To summarise all data for a country in one node is a simplification that neglects supply and demand changes within the country. Transmission losses and constraints, generation constraints and other effects that occur on a lower level than the chosen country are not taken into account. This effect is amplified by enlarging the country to a region that incorporates multiple countries. As a result, the model underestimates the costs associated with balancing the grid at every hour. Moreover, the model underestimates grid balancing and congestion management costs in minute and second time intervals, but these are a result of modelling hourly time-series.

Renewable energy production is subjected to more irregular supply when a higher spatial resolution is considered. Due to the copper plate model that is applied to IRES production, the model simulates the sun having the same weather pattern in one region and equal hourly wind speeds everywhere within a region. As a consequence, renewable energy productions reliability of supply is overestimated.

Besides simplification of the variability of renewable energy, another factor is simplified for modelling purpose. The decision to invest in IRES capacity is rooted by assuming perfect foresight. Not taking into account unpredictability overestimates the flexibility of the grid and overestimates the functionality of renewable energy production. A higher share of renewables induces higher grid balancing costs which are not taken into account in this model.

The input parameters of different technologies determine to a large extent the model outcome. Literature does not provide unified numbers for fixed and variable costs, neither for power plant efficiency, CO_2 emissions and carbon intensities for a 2°C scenario. The sensitivity analysis shows how a completely different outcome can be achieved if a set of input parameters is changed.

Renewable energy production data is based on capacity factors that are obtained by dividing the current installed capacity by the current production. Given that the capacity factors at sea generally are higher than on land, the share of currently installed capacity on land vs on sea influences the height of the capacity factor. This also means that if that ratio were to change, this would affect the height of the capacity factor. For example: 80 MW on land producing 16 MWh yields a capacity factor of 0.2. 20 MW at sea producing 8 MWh results in a capacity factor of

0.4. The weighted average would be 0.8 * 0.2 + 0.2 * 0.4 = 0.24. If the share of wind capacity increases with 20 MW, the capacity factor increases to (80 * 0.2 + 40 * 0.4)/120 = 0.267. The model finds higher shares of wind, which in reality will mostly be constructed at sea. Using this capacity factor for generation expansion planning at sea, underestimates the production capacity.

Analogous to the capacity factor, the cost parameters for wind capacity are an aggregated weighted average of costs for wind on land and wind at sea. The ratio is the same as the ratio of the capacity factors (0.91 over 0.09 for land and sea respectively).This ratio will likely change as future wind parks are mostly planned at sea. Future cost parameters for wind, therefore, underestimate the costs. This effect is partly offset by underestimating the production capacity, but not entirely. However, this is the most accurate method that fits within the scope of this research. To model this effect more accurately, offshore wind and onshore wind should be modelled separately, and increasing capacity factors from technology improvement should be taken into account.

Taking into account all of the shortcomings stated in this chapter, the model provides a comprehensive analysis of a European electricity system, whereby carbon capture and storage is carefully modelled. Important to note here is that this is not an attempt to predict a future, but merely a possible future outcome under the assumptions made in this research. Consequently, this research should serve to provide guidance, rather than be viewed as an absolute truth.

Conclusion and Recommendations

In the course of this research, a coalition of Dutch Political parties with varying political opinions and interests has been negotiating. Towards the end of this research, their coalition agreement was finished and presented. Remarkably, predominantly right-wing conservatives produced what has been called the ”greenest coalition agreement ever”. Amongst a wide range of carefully considered measures to mitigate CO_2 emissions, a highly ambitious target was set: 18 megatonnes of CO_2 will be captured and stored underground in 2030. However ambitious, in the wake of climate change, there is a good reason to strive towards reaching that ambition. By answering the research questions first proposed in section 1.4, this research might have become more relevant than was anticipated on beforehand.

This chapter is divided into three sections. Section 8.1, Conclusion, provides an answer to the main research question, based on the answers of the sub-questions. Section 8.2 gives recommendations based on the results and discussion. Section 8.3, Recommendation for Further Research, elaborates on the research gap that this research has left and provides suggestions for further research.

8.1 Conclusion

This section provides an answer to the sub-questions one by one, which ultimately form an answer to the main research question:

What is the effect of the goals set in the Paris agreement and the possibility of carbon capture and storage on a cost-optimal Western European power system plan and how is this affected by the modelling choice between linear programming and unit commitment?

The main conclusion of this research is that the system levelised Cost of Electricity generation in a future energy system is higher when the system abides by the COP21 agreement in both scenarios. However, a future system design with the implementation of CCS reduces the Levelised Cost of electricity compared to a system design without CCS. The increased costs for abiding by the Paris agreement amount to 7.09 €/MWh for a system without CCS. When the possibility of CCS is given, the cost for abiding to the Paris agreement are reduced to 3.50 €/MWh. The value of carbon capture and storage under the parameters specified in this research is 3.59 €/MWh. When the costs are optimised as a unit commitment problem, the costs are slightly increased. The levelised costs of electricity increases by 2.59%, 1.15% and 2.40% for the reference scenario, the emission constrained scenario and the emission constrained scenario with CCS, respectively.

Under the assumptions in this model, through carbon capture and storage technology, the generation capacity required to fulfil the demand at all times is significantly reduced, compared to a scenario without CCS. Implementation of CCS makes storage capacity almost completely redundant. Transmission capacity requirements are also significantly reduced since CCS is not affected by seasonal and daily weather variation. Taking into account technical limitations, the costs are increased between one and three percent, depending on the share of operational expenditures to the total system costs: larger shares of operational costs compared to fixed costs lead to larger differences.

Answer to Research Question 1: COP21 requirements for a future electricity system
The COP21 agreement dictates that the earth's temperature rise should stay within a limit of 2 °C. There are numerous ways to reach this agreement, every scenario with its own implications for the power sector and its emission targets. the International Energy Agency proposes scenarios that are subdivided into goals for all industries, including power sector goals. The 2 °C barrier relates to an absolute amount of GHG emissions that can be emitted, known as the "carbon budget". In relation to this carbon budget, the carbon intensity of generation is defined. This measure allows for modelling of the energy system independent of the countries included in that calculation. According to the IEA, the carbon intensity of electricity generation in OECD Europe should stay below 0.018 tCO_2/MWh electricity produced. This is a suitable measure to implement as a constraint in the model as a representation of the requirement for the power sector to keep within the 2 °C barrier.

Answer to Research Question 2: Aspects of the future energy system
Integration of renewable energy in the electricity system requires technologies to mitigate the effects of variability and unpredictability of electricity generation due to variation in weather patterns. Two ways in which these effects are the installation of storage capacity and increasing the size and interconnection of the transmission grid. Carbon capture and storage has been widely discussed in the policy space. While this technology is not yet utilised in the current energy system, there is a good chance that it will be in the future energy system. This is confirmed in many literary works and during the course of this research, implemented in the government's coalition agreement. Since coal and gas plants form a major part of the current energy system, they are relevant for the future energy system, whether or not they will be implemented. These technologies are needed as reference technologies.

Answer to Research Question 3: Implementation of Linear System Costs optimisation in Python
To be able to provide an answer to the main research question, a linear optimisation model is required. To this extent, an existing model was reprogrammed in Python, which is capable of running various simulations with adjustable input parameters. The model is named I-E-Energy. It uses .CSV files as input data, it runs on Python 2.7 or Python 3.4 and relies on the CPLEX solver for solving the linear optimisation problem. The output of the CPLEX solver is translated into readable files: png figures, CSV files and excel files, using Python. As an extension to the existing model, I-E-Energy implements a CO_2 emission cap, instead of a CO_2 price per tonne CO_2 emitted. This allows for the implementation of maximum carbon intensity per MWh electricity produced, consistent with the goals set by the Paris agreement. The model design, allowing for adjustable input parameters, makes the model versatile and ready to use for other research purposes, requiring only minor changes to the input data.

Answer to Research Question 4: The financial optimal solution, subject to the COP21 constraint
Running I-E-Energy and including storage, transmission and carbon capture storage, an optimal solution was found for three scenarios: a reference scenario without any CO_2 emission constraints, a scenario with an emission constraint, without the option of CCS and a scenario with a CO_2 emission constraint implemented and CCS as an option. The financially optimal solution that satisfies all constraints is presented in section 5.1.1. The levelised costs of electricity for the three scenarios is 47.76 €/MWh, 54.85 €/Mwh and 51.19 €/MWh, respectively. The

cost of abiding by the Paris agreement amounts to 7.09 €/MWh without CCS. With CCS implemented as an option, the cost of abiding by the Paris agreement is 3.42 €/MWh. The optimal solution is a mix mainly consisting of renewable energy and coal-fired generation with CCS. There is a tiny portion of biomass-fired plants that offset a part of the emission by coal-fired + CCS plants and gas-fired generation. The optimal solution required significantly more storage and transmission capacity compared to the reference scenario. For the scenario without CCS, both pumped hydro and hydrogen storage were deployed, for the scenario with CCS, pumped hydro provided sufficient storage capacity. Transmission capacity between regions was largest in the scenario without CCS, followed by the CCS scenario, congruent to the amount of renewable energy capacity that was installed.

Answer to Research Question 5: The Effect of ramping limits, startup costs, minimum on/off times and minimum generation requirements on the systems operational costs, total generation of electricity and CO_2 generation
The comparison between I-E-Energy and Powerfys, for both generation and operational costs, is presented in section 5.3.1, section 5.3.2 and section 5.3.3. There is a small portion of the costs attributed to start-up costs (shutdown costs are considered to be zero). The Powerfys model run results in all three cases in a higher levelised cost of electricity: the increase in LCOE compared to I-E-Energy was 2.59 %, 1.15 % and 2.40%, respectively for the three scenarios. This increase can be attributed to the technical limits that were introduced: ramping, startup costs and minimum on/off times. The generation profile shows that gas-fired power plants play a larger role in all three scenarios. The higher price of gas-fired generation compared to coal-fired generation is reflected in the total costs and serves as the main reason for the higher costs of electricity generation. However, the part of the results attributed to the technical constraints or differences in the model itself cannot be isolated. An undefined share of the capacity to store electricity over longer periods of time is eliminated in Powerfys. However, in the reference scenario, where storage plays a limited role and CO_2 constraints are not implemented, the cost difference remains present. Therefore, the statement that technical limits increase operational costs remains true.

Answer to Research question 6: The effect of ramping limits, startup costs, minimum on/off times and minimum generation requirements on generation of electricity, storage usage, transmission and emission
The combined effects of ramping limits, start-up costs, minimum on/off times and minimum generation requirements change the generation mix: more gas-fired power plants are used in all three scenarios. This is offset by the reduced use of coal-fired generation and other generation technologies. It means that a certain amount of available capacity for gas-fired power plants that was not used before is now utilised. For large transmission capacities, both models converge to similar net power transfer patterns. However, the overall imported and exported power of the linear I-E-Energy model is larger than that of Powerfys. This is an expected complementary effect when gas-fired power is used more frequently: as long as the maximum installed gas-power capacity is not exceeded, it is more efficient to dispatch these plants locally. In I-E-Energy, it at certain times it might have been more beneficial to concentrate coal power in one node and distribute that power over several nodes using transmission capacity since the variable costs of coal are lower. Powerfys now put stricter limits on that coal power plant, reducing the dispatched power from coal. In turn, gas power that was already installed is now utilised, on a more local level. For gas power, there is no gain in concentrating power generation in one node; its fixed costs are already low. The preferred choice is then to generate power directly where it is required. As a consequence, the power import and export is reduced.

The storage capacity is used less frequently in Powerfys than in I-E-Energy in a scenario without CCS. The high level of curtailment of renewable energy in this scenario suggests that this effect can be attributed to the model's inability to deploy seasonal storage. Compared to increasing the use of gas-fired power, storage offers free flexibility. If Powerfys were able to know future gaps in satisfying demand, it would have stored the available renewable energy instead of curtailing it. It would not be necessary to dispatch extra gas-fired power. This explanation is supported by the results from the scenario where CCS is implemented. In that scenario, the storage unit is used more frequently compared to I-E-Energy. The total use of storage, in this case, is smaller for both models. Furthermore, the small amount of curtailments suggests that seasonal effects are smaller than in the scenario without CCS. With a storage unit now at full disposal for short-term flexibility, it is used more frequently, because it has to compensate for decreased flexibility of thermal generators due to technical constraints. However, the exact effect of seasonality is an issue that remains unresolved in this research.

In a scenario with an emission constraint, Powerfys exceeds the CO_2 limit slightly. In a scenario with CCS implemented, there is more CO_2 emission than in I-E-Energy. Both effects are expected, stricter constraints increase the total costs. Hence, they increase the cost of CO_2 emission. To ensure that Powerfys also keeps to this limit, more research is required. An iterative process, where the outcomes of Powerfys are incorporated in a new I-E-Energy run, could resolve this issue.

The uncertainty surrounding carbon capture and storage technologies regarding costs, safety and technology development is significant. The sensitivity analysis shows that if carbon capture and storage technologies turn out more expensive than this research suggest, it will have a much smaller role in a future electricity system. Under the assumptions of this research, the effect only leads to a 7% decrease in LCOE compared to a scenario without carbon capture and storage, so the question remains whether this cost-benefit outweighs the risks. Coming back to the coalition partners of the Dutch cabinet, their plans to utilise carbon capture and storage should be subjected to further research before such rigorous plans are implemented. Still, this research has shown a future energy system that abides by the Paris agreement, will be positively affected by the implementation of Carbon capture and storage.

8.2 Recommendation for Relevant Actors

As more and more countries ratify the Paris agreement, it seems to be a matter of time before the European power sector will be transformed to a low-carbon industry. The actors that were discussed in chapter 2 will all face the consequences of this transition one way or another. The speed at which they are able to adapt will determine whether they can maintain their position.

Current electricity producers posses large shares of fossil fuel generation facilities. Whether it will be through tax incentives, CO_2 prices or simply because they are pushed out of the market by low marginal cost renewable energy, they are likely to be out-competed or hindered in other ways. For these actors, the availability of cheap carbon capture and storage technologies would enable their generators to keep on producing electricity in the long term. They would be wise to put time and effort into developing carbon capture and storage technologies. Also, they should diversify their portfolio to incorporate more renewable energy sources.

The transmission system operators should integrate their grid as much as possible. Currently, this is still the cheapest option to increase grid flexibility and it will continue to be this way in the near future. To account for increased decentralisation and growing shares of renewable energy capacity, they should be able to facilitate cross-border trade efficiently. This is beneficial to everyone (except peak plant producers), as it will drive down the cost and, therefore, the energy prices. If carbon capture and storage becomes a widely adopted technology, still significant grid improvements are required to provide power to the consumers in a cost-optimal way.

The European Union has put enormous effort in liberalisation of the electricity grid. They have given away centralised control of individual governments over their power producing entities to private companies. In a future without carbon capture and storage, it becomes difficult to maintain the current market structure. Prices will continue to drop as more renewable energy capacity is added, which hampers new investment. A likely future is a future where individual governments fund construction of renewable energy capacity instead of leaving it up to the market. Policy makers on a European level should realise this likely future and devise policies to best channel these transitions. Carbon capture and storage can provide grid flexibility while maintaining control over the energy supply. Policy makers should consider subsidising research for development of this technology. If eventually, CCS turns out to be too expensive as an additional technology to fossil generation, it can still be deployed in other sectors, such as the energy-intensive steel manufacturing business.

From an environmental perspective, carbon capture and storage is an expensive temporary solution. Its benefit to the power sector is questionable. However, climate scientist are still advised to consider the option. In the long run, it might provide a permanent solution, but given the current global warming pattern, every option that has a chance of mitigating CO_2 emission should be considered. As a climate scientist, one should ask the question, what if we exceed the carbon budget? In the future, it might be necessary to capture CO_2 directly from the air. That option becomes significantly more viable if the technology to capture CO_2 from power plants has been proven.

8.3 Recommendation for Further Research

The scope of the research has been established in section 1.4 and 1.3. A good research scope leaves open questions for further research. Additionally, the shortcomings of this research were discussed in chapter 7. This section describes how those shortcomings might be solved in possible further research, as well as the research gap left open in this research.

In chapter 7, one of the shortcomings discussed was the fact that only one year is modelled in this research. Any extreme weather patterns that occur less than once a year might not have occurred in that year. To create a robust energy system that can handle these fluctuations, the modelling exercise should be repeated with weather data for multiple years. Either by creating 1 optimisation problem for 5 or 6 years, or run this problem for these years separately, and measure the extremes. This would give insight into how renewable energy generation will function during 'windless winter weeks'.

In the current research, many technologies have been left out of scope, to save computational time for the high temporal resolution. A future energy system could incorporate more than just the technologies modelled in this research. The debate about the dangers and the future of nuclear energy has not yet settled. Especially in low carbon regimes, nuclear energy generation could have a large impact on the energy system. While opinions differ, this could be seen as a "necessary evil". Furthermore, CCS has been incorporated in the research, while it has not yet been widely deployed. Also, costs are expected to decrease significantly. The same argument could be mad for technologies like ocean thermal energy conversion OTEC and concentrated solar power CSP. In future research, it would be interesting to model the effects of the above-stated generation technology and see what their effect is. Analogous to the way CCS is modelled now, it could be compared to an energy system (constrained and unconstrained) with and without CSP and OTEC.

According to the COP21, the electricity sector is not the only major sector that needs to drastically reduce its greenhouse gas emissions. The phasing out of the gas network, the introduction of RES-E, more energy-efficient behaviour by consumers, and the grid-connection of electric vehicles will significantly affect the future energy system (Welsch et al., 2013). The negative consequences that are induced are higher peaks and valleys of supply curves and increased difficulty in balancing for the TSO due to fragmentation of generation (Gordijn and Akkermans, 2007). The introduction of smart grid technology has the potential to reduce these negative effects (peak shaving) and in some cases (e.g. controlled charging of EV) reverse this negative effect to add short-term storage capacity. In this model, the energy is assumed to rise linearly to a 40% increase compared to 2012 levels. However, this can be taken into account in the optimisation as well. Modelling these trends would answer questions like: How much flexibility could controlled charging offer? Another question would be: What is the effect of demand response on total system costs?

While this research focuses on a cost-optimal future energy system, it is likely that a future energy system design will not follow the assumptions made in this research, which could completely change the composition of the future energy system design. Following sudden demand changes or other future unforeseen events, there is a possibility that the particular optimal solution given by an optimisation model, might not be feasible in the future. The most optimal solution might feature certain design choices that are less favourable than others, for example, due to geopolitical reasons or other reasons that lie beyond the scope of this research. Future research might be to offer a series of solutions that lie within a certain range from that optimal solution. This way, if for whatever reason the exact optimal solution turns out not to be feasible, there is a series of other solutions that still lead to an almost optimal solution.

Reflection

And seven months later, is was finished.

Maybe a good novel would have been easier and much more fun to read. However, you have made it to this point. My advice would be to sit back and relax, go outside or grab a beer to recover from a reader unfriendly document filled with graphs, numbers and reasoning. If you do decide to stick around for a little while longer, you can read about the journey it took to arrive at this point.

In this section I reflect on the work that has been done and the process which lead to the end result. It has been a learning experience, on which I will look back with due pride. During my bachelor's program, I became fascinated with renewable energy. Especially, the combination of a complicated technical system with a strong economic influence attracts me. During the elective Electricity and Gas Markets at TU Delft, I decided I wanted to write my thesis about it.

After reading two master theses about the future Power system, I decided that I wanted to create a similar model. After searching for a while, I could not find a suitable thesis subject and decided to rethink my choice. I found something about Ocean thermal energy conversion, which was not entirely what I wanted but I decided to contact Jaco Quist, who supervised that group anyway. Pure luck brought me to Remco Verzijlbergh, who told me that his project was not about OTEC, but precisely covered what I initially wanted. Then, halfway through my research, I got a late reply from Ecofys. They told me I could continue to work on what I started on at Ecofys. The project now entailed everything I had aimed for: modelling the electricity system at a Sustainable Energy Consultancy.

Nevertheless, this project posed a huge challenge for me. I had to learn programming almost from scratch. Furthermore, I do not have an engineering background, so the formulas and analytic skills required for this thesis, I had to learn as well. There have been moments where I did not know how to continue and could not see how this thesis would ever come about. Hard work and dedication have brought me to the end. I had to push myself more than once to really dive into the numbers and to get to the bottom of the inner workings of both models.

I wanted to finish this thesis quickly. However, I underestimated the time required to compare two models and to interpret results. I had the basics of my model programmed rather quickly, but I learnt that me not being very precise could have large implications. As a beginner I programmed everything quite inefficiently, which made it hard to find errors. Eventually, after handing in the first version, I discovered an error that completely changed the model outcomes.

I enjoyed programming and I enjoyed taking on the challenge. It feels like a new world has opened for me, which I previously knew little about. However, during this process I noticed that a high level of accuracy is required to pursue a career in modelling. I am certain that I want to pursue a career in sustainability, with a strong relation to the energy market. I am not entirely sure if this career will involve as many hours of programming and energy modelling. I do hope to contribute to the sustainable energy transition and fight for a better world. I hope that I have inspired you as a reader to do the same.

Bibliography

Abrell, J. and Kunz, F. (2015). Integrating intermittent renewable wind generation-a stochastic multi-market electricity model for the european electricity market. *Networks and Spatial Economics*, 15(1):117–147.

aleasoft (2012). Assessment of electricity prices in western europe for 2012.

Ashfaq, A. and Khan, A. Z. (2014). Optimization of economic load dispatch problem by linear programming modified methodology. In *International Conference on Emerging Trends in Engineering and Technology*.

Bakker, E. (2017). *Frictional and transport properties of simulated faults in CO2 storage reservoirs and clay-rich caprocks*. PhD thesis, UU Dept. of Earth Sciences.

Bertsch, J., Growitsch, C., Lorenczik, S., and Nagl, S. (2012). Flexibility options in european electricity markets in high res-e scenariosstudy on behalf of the international energy agency. *Cologne, Germany: Energiewirtschaftliches Institut an Der Universität Zu Köln (EWI)*.

Beveridge, R. and Kern, K. (2013). The energiewende in germany: background, developments and future challenges. *Renewable Energy L. & Pol'y Rev.*, page 3.

Brouwer, A. S., Van Den Broek, M., Seebregts, A., and Faaij, A. (2014). Impacts of large-scale intermittent renewable energy sources on electricity systems, and how these can be modeled. *Renewable and Sustainable Energy Reviews*, 33:443–466.

Brouwer, A. S., van den Broek, M., Zappa, W., Turkenburg, W. C., and Faaij, A. (2016). Least-cost options for integrating intermittent renewables in low-carbon power systems. *Applied energy*, 30:48–74.

Bussar, C., Moos, M., Alvarez, R., Wolf, P., Thien, T., Chen, H., Cai, Z., Leuthold, M., Sauer, D. U., and Moser, A. (2014). Optimal allocation and capacity of energy storage systems in a future european power system with 100% renewable energy generation. *Energy Procedia*, 46:40–47.

Bussar, C., Stöcker, P., Cai, Z., Moraes Jr, L., Magnor, D., Wiernes, P., van Bracht, N., Moser, A., and Sauer, D. U. (2016). Large-scale integration of renewable energies and impact on storage demand in a european renewable power system of 2050sensitivity study. *Journal of Energy Storage*, 6:1–10.

Christoff, P. (2016). The promissory note: Cop 21 and the paris climate agreement. *Environmental Politics*, 25(5):765–787.

Conejo, A. J., Castillo, E., Minguez, R., and Garcia-Bertrand, R. (2006). *Decomposition techniques in mathematical programming: engineering and science applications*. Springer Science & Business Media.

Cook, J., Nuccitelli, D., Green, S. A., Richardson, M., Winkler, B., Painting, R., Way, R., Jacobs, P., and Skuce, A. (2013). Quantifying the consensus on anthropogenic global warming in the scientific literature. *Environmental research letters*, 8(2):024024.

Dave, S., Sooriyabandara, M., and Yearworth, M. (2011). A systems approach to the smart grid. *ENERGY*, pages 130–134.

De Koning, H. and Deetman (2014). Scenarios for a 2-degree world.

De Pater, T. (2016). Towards a cost- optimal european power system for a renewable future.

Després, J., Hadjsaid, N., Criqui, P., and Noirot, I. (2015). Modelling the impacts of variable renewable sources on the power sector: Reconsidering the typology of energy modelling tools. *Energy*, 80:486–495.

DG-Energy (2012a). Quarterly report on european electricity markets, first quarter. Technical report, European Commission.

DG-Energy (2012b). Quarterly report on european electricity markets, second quarter. Technical report, European Commission.

Doughty, C., Freifeld, B. M., and Trautz, R. C. (2008). Site characterization for co2 geologic storage and vice versa: the frio brine pilot, texas, usa as a case study. *Environmental Geology*, 54(8):1635–1656.

Drummond, P. (2014). Scenarios for a low-carbon europe for 2050: Discussion of results from the etm–ucl model, exiobase input–output model and the ginfors model. *Choosing Efficient Combinations of Policy Instruments for Low-carbon development and Innovation to Achieve Europe's*, 2050.

EEA (2016). Overview of electricity production and use in europe. Technical report, European Environment Agency.

Energy, D. (2012). Quarterly report on european electricity markets, third and fourth quarter. Technical report, European Commission.

ENTSO-E (2015). Hourly load values of a specific country for a specific month (aggregated for 2 years). retrieved from https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx.

Fürsch, M., Hagspiel, S., Jägemann, C., Nagl, S., Lindenberger, D., and Tröster, E. (2013). The role of grid extensions in a cost-efficient transformation of the european electricity system until 2050. *Applied Energy*, 104:642–652.

Geels, F. W. (2004). From sectoral systems of innovation to socio-technical systems: Insights about dynamics and change from sociology and institutional theory. *Research policy*, 33(6):897–920.

Gibbins, J. and Chalmers, H. (2008). Carbon capture and storage. *Energy policy*, 36(12):4317–4322.

Gils, H. C., Scholz, Y., Pregger, T., de Tena, D. L., and Heide, D. (2017). Integrated modelling of variable renewable energy-based power supply in europe. *Energy*, 123:173–188.

Gimeno-Gutiérrez, M. and Lacal-Arántegui, R. (2013). Assessment of the european potential for pumped hydropower energy storage. *JRC Scientific and Policy Report*.

Gordijn, J. and Akkermans, H. (2007). Business models for distributed generation in a liberalized market environment. *Electric Power Systems Research*, 77(9):1178–1188.

Gough, C. and Upham, P. (2011). Biomass energy with carbon capture and storage (beccs or bio-ccs). *Greenhouse Gases: Science and Technology*, 1(4):324–334.

Graedel, T. E. and Allenby, B. R. (2010). *Industrial ecology and sustainable engineering*. Prentice Hall.

Haller, M., Ludig, S., and Bauer, N. (2012). Decarbonization scenarios for the eu and mena power system: Considering spatial distribution and short term dynamics of renewable generation. *Energy Policy*, 47:282–290.

Hentschel, J., Spliethoff, H., et al. (2016). A parametric approach for the valuation of power plant flexibility options. *Energy Reports*, 2:40–47.

Huber, M., Dimkova, D., and Hamacher, T. (2014). Integration of wind and solar power in europe: Assessment of flexibility requirements. *Energy*, 69:236–246.

IBM (2014). Cplex optimization modeling using python.

IEA (2016a). Energy, climate change and environment 2016 insights. Technical report, IEA, International Energy Agency, Paris.

IEA (2016b). World energy outlook.

IEA, E. (2015). =energy technology perspectives 2015: Mobilising innovation to accelerate climate action. Technical report, OECD/IEA, Paris.

IEAGHG (2009). Biomass ccs study. Technical report, IEA Greenhouse Gas R&D Programme.

IEAGHG (2011a). Global potential of biomass combined with carbon capture and storage. Technical report, IEA, International Energy Agency, Paris.

IEAGHG (2011b). Potential for biomass and carbon dioxide capture and storage. Technical report, IEA Greenhouse Gas R&D Programme.

Jägemann, C., Fürsch, M., Hagspiel, S., and Nagl, S. (2013). Decarbonizing europe's power sector by 2050—analyzing the economic implications of alternative decarbonization pathways. *Energy Economics*, 40:622–636.

Jebaraj, S. and Iniyan, S. (2006). A review of energy models. *Renewable and Sustainable Energy Reviews*, 10(4):281–311.

Kinley, R. (2017). Climate change after paris: from turning point to transformation. *Climate Policy*, 17(1):9–15.

Koelbl, B. S., Wood, R., van den Broek, M. A., Sanders, M. W., Faaij, A. P., and van Vuuren, D. P. (2015). Socio-economic impacts of future electricity generation scenarios in europe: Potential costs and benefits of using co 2 capture and storage (ccs). *International Journal of Greenhouse Gas Control*, 42:471–484.

Künneke, R., Groenewegen, J., and Ménard, C. (2010). Aligning modes of organization with technology: Critical transactions in the reform of infrastructures. *Journal of Economic Behavior & Organization*, 75(3):494–505.

Leung, D. Y., Caramanna, G., and Maroto-Valer, M. M. (2014). An overview of current status of carbon dioxide capture and storage technologies. *Renewable and Sustainable Energy Reviews*, 39:426–443.

Levy, Y. and Ellis, T. J. (2006). A systems approach to conduct an effective literature review in support of information systems research. *Informing Science: International Journal of an Emerging Transdiscipline*, 9(1):181–212.

Lohwasser, R. and Madlener, R. (2012). Economics of ccs for coal plants: Impact of investment costs and efficiency on market diffusion in europe. *Energy Economics*, 34(3):850–863.

Lopes, J. P., Hatziargyriou, N., Mutale, J., Djapic, P., and Jenkins, N. (2007). Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities. *Electric power systems research*, 77(9):1189–1203.

Mapchart.net (2016). Mapchart.

Marx, J., Schreiber, A., Zapp, P., Haines, M., Hake, J.-F., and Gale, J. (2011). Environmental evaluation of ccs using life cycle assessment–a synthesis report. *Energy Procedia*, 4:2448–2456.

Mercure, J.-F. and Salas, P. (2013). On the global economic potentials and marginal costs of non-renewable resources and the price of energy commodities. *Energy Policy*, 63:469–483.

Obama, B. (2017). The irreversible momentum of clean energy. *Science*, 355(6321):126–129.

Ooi, R. E., Foo, D. C., Tan, R. R., Ng, D. K., and Smith, R. (2013). Carbon constrained energy planning (ccep) for sustainable power generation sector with automated targeting model. *Industrial & Engineering Chemistry Research*, 52(29):9889–9896.

Ortner, A. (2014). Transmission grid representations in power system models-a ptdf based approach. In *Energy & the Economy, 37th IAEE International Conference, June 15-18, 2014*. International Association for Energy Economics.

Pfenninger, S. and Staffell, I. (2016). Long-term patterns of european pv output using 30 years of validated hourly reanalysis and satellite data. *Energy*, 114:1251–1265.

REN21 (2016). Global status report. Technical report, Renewable Energy Policy Network for the 21st Century.

Rhodes, J. S. and Keith, D. W. (2005). Engineering economic analysis of biomass igcc with carbon capture and storage. *Biomass and Bioenergy*, 29(6):440–450.

Rittel, H. W. and Webber, M. M. (1973). Dilemmas in a general theory of planning. *Policy sciences*, 4(2):155–169.

Roadmap, E. (2010). 2050: a practical guide to a prosperous, low carbon europe. *Brussels: ECF*.

Rodriguez, R. A., Becker, S., Andresen, G. B., Heide, D., and Greiner, M. (2014). f. *Renewable Energy*, 63:467–476.

Rowley, J. and Slack, F. (2004). Conducting a literature review. *Management Research News*, 27(6):31–39.

Salahuddin, M. and Gow, J. (2014). Economic growth, energy consumption and co 2 emissions in gulf cooperation council countries. *Energy*, 73:44–58.

Sanchez, D. L., Nelson, J. H., Johnston, J., Mileva, A., and Kammen, D. M. (2015). Biomass enables the transition to a carbon-negative power system across western north america. *Nature Climate Change*, 5(3):230–234.

Sargent, R. G. (2004). Validation and verification of simulation models. In *Proceedings of the 36th conference on Winter simulation*, pages 17–28. Winter Simulation Conference.

Schaber, K., Steinke, F., and Hamacher, T. (2012a). Transmission grid extensions for the integration of variable renewable energies in europe: Who benefits where? *Energy Policy*, 43:123–135.

Schaber, K., Steinke, F., Mühlich, P., and Hamacher, T. (2012b). Parametric study of variable renewable energy integration in europe: Advantages and costs of transmission grid extensions. *Energy Policy*, 42:498–508.

Schmid, E. and Knopf, B. (2015). Quantifying the long-term economic benefits of european electricity system integration. *Energy Policy*, 87:260–269.

Schröder, A., Kunz, F., Meiss, J., Mendelevitch, R., and Von Hirschhausen, C. (2013). Current and prospective costs of electricity generation until 2050. Technical report, Data Documentation, DIW.

Spiecker, S. and Weber, C. (2014). The future of the european electricity system and the impact of fluctuating renewable energy–a scenario analysis. *Energy Policy*, 65:185–197.

Steinke, F., Wolfrum, P., and Hoffmann, C. (2013). Grid vs. storage in a 100% renewable europe. *Renewable Energy*, 50:826–832.

Tseng, C.-L., Li, C., and Oren, S. (2000). Solving the unit commitment problem by a unit decommitment method. *Journal of Optimization Theory and Applications*, 105(3):707–730.

Van Alphen, K., tot Voorst, Q. v. V., Hekkert, M. P., and Smits, R. E. (2007). Societal acceptance of carbon capture and storage technologies. *Energy Policy*, 35(8):4368–4380.

Van den Bergh, K. and Delarue, E. (2015). Cycling of conventional power plants: technical limits and actual costs. *Energy Conversion and Management*, 97:70–77.

Van Staveren, R. (2014). The role of electrical energy storage in a future sustainable electricity grid.

Verbong, G. P. and Geels, F. W. (2010). Exploring sustainability transitions in the electricity sector with socio-technical pathways. *Technological Forecasting and Social Change*, 77(8):1214–1221.

Verzijlbergh, R., Martínez-Anido, C. B., Lukszo, Z., and de Vries, L. (2014). Does controlled electric vehicle charging substitute cross-border transmission capacity? *Applied Energy*, 120:169–180.

Weitemeyer, S., Kleinhans, D., Vogt, T., and Agert, C. (2015). Integration of renewable energy sources in future power systems: The role of storage. *Renewable Energy*, 75:14–20.

Welsch, M., Bazilian, M., Howells, M., Divan, D., Elzinga, D., Strbac, G., Jones, L., Keane, A., Gielen, D., Balijepalli, V. M., et al. (2013). Smart and just grids for sub-saharan africa: exploring options. *Renewable and Sustainable Energy Reviews*, 20:336–352.

Zakeri, B. and Syri, S. (2015). Electrical energy storage systems: A comparative life cycle cost analysis. *Renewable and Sustainable Energy Reviews*, 42:569–596.

Appendix A - Mathematical Model

The mathematical formulation of the model by De Pater is presented in this appendix. The chapter contains three sections. Section A.1 contains a description of the objective function and its constraints and bounds. Section A.2 contains the mathematical formulation of the objective function and its constraints. Section x contains the explanation of the variables.

A.1 Model in Words

A.1.1 Model concept

Minimize

- Total system costs for the European power system, subject to:
  - Fixed costs for generation technologies: wind, solar, gas, coal, biomass with CCS.
  - Fixed costs for capacity of storage conversion technologies and storage capacities: Flow batteries, Pumped hydro storage and Hydrogen.
  - Fixed costs for interconnection transmission lines.
  - Variable costs for conventional generation technologies: Gas, Coal and Biomass with CCS.

Subject to:

- Power balance requirements:
  - Power generated + imported + discharged - exported - charged equals demand in every country at each timestep
  - The power charged into a storage is added to the storage-level, minus efficiency losses. The power discharged from storage is deducted from storage level, plus efficiency losses.
  - The exported electricity from country n to m equals the imported power in country m from n, minus efficiency losses.
- Generation Limitations:
  - Output from conventional generation technologies stays below the installed capacity.
  - Output from RES-E stays below the installed capacity multiplied by the potential output per capacity (due to meteorological conditions).
- Storage limitations:
  - The power flowing in and out storage cannot exceed the installed conversion capacity.
  - The energy in storage cannot exceed the installed storage capacity.
  - The energy in storage at the start is the same as the stored energy at the end.
- Transmission limitations:
  - The power flowing from country n to m can never exceed the installed capacity between country n and m.

with bounds:

- lower bounds:
  - all lower bounds
- Upper bounds:
  - Installed PHS storage capacity in any country can never exceed the technical potential for that country.
  - All other upper bounds are infinite.

A.2 Equations of the Model

A.2.1 Objective Function

$$\text{minimize } TC = FC + VC \tag{A.1}$$

$$FC = \sum_{i \in I \bigcup E} \alpha_i * \omega_i * \sum_{n \in N} (IC_{i,n}) + \sum_{i \in S} \alpha_i * \mu_i * \sum_{n \in N} (IS_{i,n}) + \psi * \beta * \sum_{n \in N} \sum_{m \in M_n} (\delta_{n,m} * TR_{n,m}) \tag{A.2}$$

$$VC = \sum_{i \in G} \nu_i * \sum_{n \in N} \sum_{t \in T} P_{i,n,t} \tag{A.3}$$

$$\alpha_i = \frac{R}{(\varphi * Y)} \quad \forall i \in I \tag{A.4}$$

$$\beta = \frac{R}{(\rho * Y)} \tag{A.5}$$

A.2.2 Equality constraints

Power Balance

$$ED_{n,t} = \sum_{i \in G} P_{i,n,t} + \sum_{i \in S} (CP_{i,n,t} - DP_{i,n,t}) + \sum_{m \in M_n} (IP_{n,m,t} - EP_{n,m,t}) \;\; \forall n \in N \;\; \forall m \in M \;\; \forall t \in T \tag{A.6}$$

Storage Equality constraints

$$SP_{i,n,t} = SP_{i,n,t-1} + \gamma_i * CP_{i,n,t} - \frac{1}{\eta_i} DP_{i,n,t} \;\; \forall i \in S \;\; \forall n \in N \;\; \forall t \in T \tag{A.7}$$

$$SP_{i,n,t_{max}} = SP_{i,n,t_0} \;\; \forall i \in S \;\; \forall n \in N \;\; \forall t \in T \tag{A.8}$$

Transmission Equality constraints

$$IP_{n,m,t} = \tau^{\delta_{n,m}} * EP_{m,n,t} \tag{A.9}$$

$$TR_{n,m} = TR_{m,n} \;\; \forall n \in N \;\; \forall m \in M \tag{A.10}$$

Help Variables

$$P_{RES} = \sum_{i \in G} \vartheta_i * \sum_{n \in N} \sum_{t \in T} P_{i,n,t} \tag{A.11}$$

$$P_{GEN} = \sum_{i \in G} \sum_{n \in N} \sum_{t \in T} P_{i,n,t} \tag{A.12}$$

A.2.3 Inequality Constraints

Dispatch Inequality Constraints

$$P_{i,n,t} \leq CF_{i,n,t} * IC_{i,n,t} \;\; \forall i \in G \;\; \forall n \in N \;\; \forall t \in T \tag{A.13}$$

Storage Inequality Constraints

$$SP_{i,n,t} \leq IS_{i,n,t} \;\; \forall i \in S, \;\; \forall n \in N \;\; \forall t \in T \tag{A.14}$$

$$CP_{i,n,t} \leq IC_{i,n} \;\; \forall i \in E \;\; \forall n \in N \;\; \forall t \in T \tag{A.15}$$

$$DP_{i,n,t} \leq IC_{i,n} \;\; \forall i \in E \;\; \forall n \in N \;\; \forall t \in T \tag{A.16}$$

Transmission Inequality Constraints

$$IP_{n,m,t} + EP_{m,n,t} \leq TR_{n,m} \;\; \forall n \in N \;\; \forall m \in M_n \tag{A.17}$$

RES-E Requirement Constraint

$$\epsilon * P_{generated} \leq P_{RES} \tag{A.18}$$

A.3 Overview of Sets, Parameters and Variables

Sets	
Notation	Description
I	Over coupling set of generation and storage technologies
G	Subset of relevant Generation Technologies
E	Subset of relevant conversion technologies
S	Set of relevant energy storage capacity technologies
N	Set of all considered nations
M_n	Set of neighbouring nations n
T	The number of time steps included

	Parameters	
Notation	Description	Unit
$ED_{n,t}$	Electricity Demand	MWh
$CF_{i,n,t}$	Capacity factor for renewable energy production	fraction
$\delta_{n,m}$	Distance between geographical center of regions/countries	km
ω	Fixed costs of generation and conversion technologies	€/MW
μ	Fixed costs of storage reservoirs	€/MWh
β	Fixed costs of transmission line	€/MW
ν	Variable cost of generation	€/MWh
φ	Lifetime of Generation and storage technologies	year
ρ	Lifetime of transmission line	year
α_i	Time cost factor (to calculate hourly costs from lifetime investments) for generation and storage technologies	/hour
β_i	Time cost factor (to calculate hourly costs from lifetime investments of transmission capacity	/hour
R	Hours of the run considered	/hour
Y	Hours in a year	hour
τ	Transmission loss as a base of the distance	/%km
γ	charging efficiency	%
η	Discharging efficiency	%
θ	Sustainable energy fraction	%

Variables		
Notation	Description	Unit
TC	Total Costs	€
FC	Fixed Costs	€
VC	Variable Costs	€
$IC_{i,n}$	Installed generation and conversion capacities	MW
$IS_{i,n}$	Installed storage capacities	MWh
$TR_{n,m}$	Installed transmission capacities	MW
$P_{i,n,t}$	Power generated	MWh
$DP_{i,n,t}$	Power discharged from storage	MWh
$CP_{i,n,t}$	Power charged to storage	MWh
$SP_{i,n,t}$	Level of Energy in storage	MWh
$IP_{n,m,t}$	Imported Power	MWh
$EP_{n,m,t}$	Exported Power	MWh

Appendix B - Cost Parameters

B.1 Cost parameters Solar and Wind

The basis for most cost parameters is De Pater (2016). However, wind and solar parameters differ for three main reasons:

- De Pater (2016) based both capital costs and fixed Operation and maintenance costs for wind power only on onshore wind power. However, the renewable energy production data (section 3.3.4) provided by Pfenninger and Staffell (2016) consider both productions of onshore and offshore wind power. The capacity factor share on land and at sea is 91% and 9% respectively (this is explained in section 3.3.4. This division should be maintained in the costs. The costs for wind on land are much lower than they are at sea. The closest simple adaption to make sure that the costs and capacity factors are aligned and distribute those costs between installation of new wind capacity is to take the same weighted average for the investment costs.
- De Pater (2016) considers a dual axis tracking device for solar PV. Since Pfenninger and Staffell (2016) considers a single axis tracking device for determination of the capacity factors, this should be reflected in the costs as well.
- Both the wind and solar investment costs have changed significantly and are expected to decrease even more as a result of technology improvements. This study considers a 2050 scenario. The costs for wind and solar (as well as all other costs) should reflect 2050 projections.

Taking these three reasons into account, wind and solar projections were recalculated based on four literary sources (Bertsch et al., 2012; Bussar et al., 2016; Fürsch et al., 2013; Gils et al., 2017). Also, the costs were weighted according to the capacity factors in Pfenninger and Staffell (2016). The parameters are presented in table B.3.

B.2 Carbon Capture and Storage Parameters

The cost for carbon capture and storage are difficult to estimate. Cost range widely. Taking averages would not make much sense, as the costs should reflect the costs of the conventional generation, supplemented with the costs for CCS, for fair comparison. Therefore, the cost for CCS ONLY are required, separated from the cost of the generation plant. These costs are given in table B.1.

Generation Technology	CAPEX (€/kW)	FOM (€/kW/yr)
Coal CCS	385	23
CCGT CCS	422	31
Biomass CCS	385	29

Table B.1: *This table represents the additional costs associated with carbon capture and storage. The final input parameters used in the model for CCS technologies, are defined as the sum of the techno-economic parameters from table B.2 and the figures in this table (IEAGHG, 2011b).*

B.3 Parameters by de Pater

Table B.2 gives an overview of the current cost parameters. These are the figures used by de Pater and for the validation run for the real world scenario. As future technologies, coal, gas and Biomass technology is retained: they are considered mature technologies, and prices are not expected to change much.

Generation Technology	CAPEX (€/kW)	FOM (€/kW/yr)	VOM (€/kWh)	Lifetime (yr)	Efficiency (%)
Wind	1435	40	0	25	100
Solar PV	1560	25	0	25	100
Coal	1600	28	30	42.5	47
CCGT	800	20	46	30	60
Biomass	2640	90	84.5	33	35

Table B.2: *This table shows the techno-economic parameters of Generation technologies in 2015. It shows capital expenditures (CAPEX), fixed operation and maintenance costs (FOM), variable operation and maintenance costs (VOM), the lifetime of the technology and its generation efficiency.*

2050 RES	Wind Onshore			Wind Offshore			Weigthed Average Wind		Solar PV	
Source	CAPEX	FOM	Weight (%)	CAPEX	FOM	Weight (%)	CAPEX	FOM	CAPEX	FOM
Bertsch et al. (2012)	1121	30	0.91	2615	128	0.09	1255	38.82	1199	30
Bussar et al. (2016)	1000	-	0.91	2000	-	0.09	1045	18.6	600	17
Fürsch et al. (2013)	1160	41	0.91	2607	156	0.09	1290	51.35	1190	30
Gils et al. (2017)	1103	36	0.91	1800		0.09	1219	41.67	700	8.5
Average	1096	35.5	0.91	2305.5	142	0.09	**1205**	**45**	**925**	**21**

Table B.3: *Investment costs 2050 for wind and solar PV*

B.4 Cost parameters Final

The parameters from the previous sections in this appendix are combined into one table. These are the cost parameters used in model I-E-Energy. This means that the techno-economic parameters for coal, gas CCGT and biomass are based on De Pater, the rest is based on the parameters presented in table B.3 and table B.1.

Current 2012/2015 parameters	Generation Technology	CAPEX (€/kW)	FOM (€/kW/yr)	VOM (€/kWh)	Lifetime (yr)	Pollution factor (gCO2 / KWh el)	Efficiency	Fuel costs (€/kWh th)	Pollution factor (gCO2 / KWh th)
Table C.1.	Wind	1205	45	0	25	0	1	0	0
Table C.1.	Solar PV	925	21	0	25	0	1	0	0
De Pater (2016)	CCGT	800	20	46	30	0.28	0.6	27.6	0.168
De Pater (2016)	Hard coal	1600	28	30	42.5	0.48	0.47	14.1	0.2256
De Pater (2016)	Biomass	2640	90	84.5	33	0.035	0.35	29.575	0.01225
De Pater (2016); IEAGHG (2011b)	Coal CCS	1985	51	37.5	42.5	0.05	0.47		
De Pater (2016); IEAGHG (2011b)	Gas CCGT CCS	1222	51	66.7	30	0.102	0.6		
De Pater (2016); IEAGHG (2011b)	Biomass CCS	3025	119	143.5	33	-1.44	0.35		

Table B.4: *2050 cost parameters by Source. The CCS investment parameters are the sum of the original costs by De Pater (2016) and IEAGHG (2011b).*

B.5 Storage Parameters

All storage parameters are 2050 projections. The sources on which they are based are Bussar et al. (2016), Steinke et al. (2013), Zakeri and Syri (2015). The resulting figures are averages. The figures found by De Pater (2016), the parameters for the storage technologies could not be verified. Therefore, the approach to find storage parameters was different than for generation technologies. Also, all these three sources provided the complete set of data required for the modelling setup of I-E-Energy.

Storage Bussar	**Capex Conversion**	**Capex Storage Reservoir**	**FO&M**	**VO&M**	**Lifetime**	**Efficiency**
Battery storage	75	111		0	25	0.98
Hydro pumped	840	20		0	60	0.9
H2	400	0.3		0	40	0.62
Storage Steinke	**Capex Conversion**	**Capex Storage Reservoir**	**FO&M**	**VO&M**	**Lifetime**	**Efficiency**
Battery storage	100	100	50	0	10	0.95
Hydro pumped	500	50	50	0	40	0.92
H2 (with methanisation)	2000	1	50	0	40	0.55
Storage Zakeri	**Capex Conversion**	**Capex Storage Reservoir**	**FO&M**	**VO&M**	**Lifetime**	**Efficiency**
Battery storage	490	470	8.5	0	10	0.92
Hydro pumped	530	68	4.6		60	0.91
H2	200	60	30	0	17.5	0.61
Average Storage Parameters	**Capex Conversion**	**Capex Storage Reservoir**	**FO&M**	**VO&M**	**Lifetime**	**Efficiency**
Battery storage	222	227	29	0	15	0.95
Hydro pumped	623	46	27	0	53	0.91
H2	867	20	40	0	33	0.59

Figure B.1: *Sources on which the storage parameters for 2050 are based and their corresponding figures (Bussar et al., 2016; Steinke et al., 2013; Zakeri and Syri, 2015)*

Appendix C - Validation

C.1 LCOE Parameters Current Averages

Area	2012 q1	2012 q2	2012 q3
Central western Europe	-	40.7	37
British Isle	50	50	60
Nordic	37.2	31.7	30
Italy	80	75.3	67
Iberian Peninsula	60	55	44
Quarterly average	56.8	50.54	48
Yearly average	51.62666667		

Table C.1: *Average Regional Spot prices (€/MWh). The figures are based on DG-Energy (2012a,b); Energy (2012)*

Country	Power exchange	Wholesale Price
Spain, Portugal	MIBEL	47.24
France	POWERNEXT	46.94
Germany	PHELIX	42.59
UK	N2EX	55.1
Italy	IPEX	75.48
EU average	-	53.47

Table C.2: *Average of 5 leading European Power exchange wholesale prices in €/ MWh. The figures are based on aleasoft (2012).*