Electricity sector decarbonization in Germany and Europe

A model-based analysis of operation and infrastructure investments

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Clemens Gerbaulet
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Promotionsausschuss:

Vorsitzender:	Prof. Dr. Karsten Neuhoff
Gutachter:	Prof. Dr. Christian von Hirschhausen
Gutachterin:	Prof. Dr. Claudia Kemfert (Hertie School of Governance, DIW Berlin)
Gutachter:	Dr. Friedrich Kunz (DIW Berlin)

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Zusammenfassung

In dieser Dissertation werden Forschungsfragen zur Transformation des Stromsektors in Deutschland und Europa im Rahmen der Dekarbonisierung behandelt. Der erste Teil befasst sich mit Marktentwicklungen und operativen Aspekten im Kontext dieser Sektortransformation. Im ersten Kapitel wird ELMOD-MIP eingeführt, ein Kraftwerkseinsatzmodell für Deutschland mit einer genauen Abbildung von Regelleistung. Es analysiert den Regelleistungsmarkt in Deutschland 2025. Bei gleichbleibenden Marktrahmenbedingungen steigen die Kosten im Vergleich zu 2013; jedoch verringert die Beteiligung von Windenergie die Gesamtkosten der Regelleistungsbereitstellung um 40%. Im zweiten Kapitel wird ELMOD-MIP um die Schweiz und Österreich erweitert und grenzüberschreitende Zusammenarbeit im Regelleistungsmarkt analysiert. Gemeinsame Beschaffung ist die vorteilhafteste Form der Zusammenarbeit und hat keine negativen Auswirkungen auf den Spotmarkt. Der Einfluss der Elektromobilität auf den Kraftwerkseinsatz in Deutschland wird im dritten Kapitel analysiert, welches eine Methodik zur Darstellung verschiedener EV-Lademodi beinhaltet. Ungesteuertes Aufladen erfolgt tagsüber und abends und führt zu hohen Lastspitzen; kostenbasierte Ladung verschiebt diese zu Stunden mit hoher Solarverfügbarkeit und der Nacht, kann aber die spezifischen CO_2-Emissionen der EVs negativ beeinflussen.

Der zweite Teil befasst sich mit Netzausbau im Übertragungsnetz. Das erste Kapitel beschreibt den Prozess und die Rolle der Netzplanung in Deutschland und kommt zu dem Schluss, dass die derzeitige Geschwindigkeit des Netzausbaus keine verlangsamende Wirkung auf die Sektortransformation hat. Das zweite Kapitel analysiert die Wirkung nichtregulierter Investitionen in Interkonnektoren in der Ostseeregion. Diese Investitionen führen zu einer Wohlfahrtssteigerung, die aber weitgehend von den Investierenden abgeschöpft werden und reizen diese dazu an, in suboptimale Netzkonfigurationen zu investieren. Das dritte Kapitel präsentiert ein Modell zur Ermittlung von Netzinvestitionen in Europa. Der Bedarf an Übertragungsnetzinvestitionen in Europa bis 2050 hängt vom Erzeugungsportfolio ab. Die größte Auswirkung auf das Volumen und die regionale Struktur der Netzinvestitionen wird durch die Treibhausgasemissionsreduzierungsziele exogen vorgegebener Erzeugungsportfolios induziert. Hohe Reduktionsziele erfordern große zusätzliche Netzinvestitionen.

Der dritte Teil nimmt eine dynamische Investitionsperspektive in die Erzeugungs- und Übertragungskapazitäten in Europa bis 2050 ein. Das erste Kapitel präsentiert dynELMOD, ein Investitions- und Kraftwerkseinsatzmodell für den europäischen Stromsektor. Unter vollständiger Dekarbonisierung werden überwiegend erneuerbare Energien in Verbindung mit Speicherkapazitäten für die Stromerzeugung im Jahr 2050 in Europa genutzt. Das zweite Kapitel konzentriert sich auf Szenarien für die Dekarbonisierung des europäischen Elektrizitätssektors, unter Berücksichtigung von Rahmenbedingungen wie die Voraussicht der Planer. Investitionen unter kurzfristiger Planung führen zu erhöhtem Kraftwerksausbau. In einem Budgetansatz kann das Modell Emissionen zwischen Zeitschritten frei verteilen, um kostenminimierende Transformationsraten zu ermitteln.

Stichwörter: Stromsektor, Dekarbonisierung, Erzeugungsinvestitionen, Netzausbau, Elektromobilität, Regelleistung, Regionale Kooperation, Open Source

Abstract

This thesis focuses on research questions and implications in the context of the electricity sector decarbonization in Germany and Europe.

The first part deals with market developments and operational aspects in the context of this electricity sector transformation. Its first chapter presents ELMOD-MIP, a unit commitment model for Germany with a representation of balancing reserves. The balancing reserves market in Germany of 2025 is analyzed. Costs increase compared to 2015 if the market remains the same; with the participation of wind turbines balancing reservation and activation cost decrease by 40%. The second chapter extends ELMOD-MIP to also include Switzerland and Austria and analyzes cross-border cooperation on balancing reserves. Cross-border procurement is the most beneficial form of cooperation and does not negatively affect cross-border spot market operations. The influence of electromobility on power plant dispatch is analyzed in the third chapter, which presents a methodology to represent different EV charging modes. Uncontrolled charging occurs at daytime and in the evening leading to high peak demands; cost-driven charging shifts towards hours with high solar availability and the night but can negatively impact the EVs' specific CO_2 emissions.

The second part deals with investments into the high voltage electricity grid. The first chapter describes the process and role of network planning in Germany and concludes that the current level of grid investments is not a limiting factor of the energiewende. The second chapter analyzes the effect of merchant interconnector investments in the Baltic Sea region using a two-stage model setup. Allowing merchants leads to a welfare increase, but it is largely pocketed by the merchant. The merchant is also incentivized to invest into suboptimal configurations. The third chapter presents a model to determine grid investments in Europe. The need for transmission investment in Europe until 2050 depends on generation technology choices. Investments are lower than assumed. The largest effect on grid expansion in terms of volume and regional structure is induced by the GHG emission reduction targets of the exogenously given generation portfolios. High mitigation scenarios require large additional network investments.

The third part assumes a dynamic investment perspective into generation and transmission capacities in Europe until 2050. Its first chapter presents dynELMOD, a cost-minimizing investment and dispatch model for the European electricity sector. Under full decarbonization, mostly renewables combined with storage capacities provide the electricity generation in 2050 in Europe. The second chapter focuses on scenarios for the decarbonization of the European electricity sector focusing on boundary conditions such as the planners' foresight using scenarios with reduced foresight or an emission budget approach. Investing under a myopic horizon leads to stranded assets. In the budgetary approach, the model is free to distribute emissions between time steps within a budget. This gives insights in low cost decarbonization paths in the electricity sector.

Keywords: Electricity sector, decarbonization, generation investments, grid expansion, electromobility, balancing reserves, regional cooperation, open source

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As the writing of this thesis has concluded, now we can start to work!

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List of Abbreviations

AC . . . . . Alternating Current
ACER . . . . Agency for the Cooperation of Energy Regulators
aFRR . . . . . Automatic Frequency Restoration Reserve
BEMIP . . . . Baltic Energy Market Interconnection Plan
BEV . . . . . Battery-Electric Vehicle
BNetzA . . . Federal Network Agency (Bundesnetzagentur)
BRP . . . . . Balancing Responsible Party
BSP . . . . . Balancing Service Provider
CCGT . . . . Combined Cycle Gas Turbine
CCTS . . . . Carbon Capture, Transport, and Storage
CHP . . . . . Combined Heat and Power
CMOL . . . . Common Merit Order List
CO_2 . . . . . Carbon Dioxide
CoBA . . . . . Coordinated Balancing Area
CSP . . . . . Concentrated Solar Power
CWE . . . . . Central Western Europe
DC . . . . . Direct Current
DCLF . . . . Direct-Current Load Flow
dena . . . . . German Energy Agency (deutsche energieagentur)
DNLP . . . . Discontinuous Non-Linear Program
DSM . . . . . Demand Side Management
DSO . . . . . Distribution System Operator
DVG . . . . . Deutsche Verbundgesellschaft
E/P-Ratio . . Energy to Power Ratio
EC . . . . . European Commission
EEG . . . . . German Renewable Energy Sources Act
EHV . . . . . Extra High Voltage
EMF . . . . . Energy Modeling Forum
ENTSO-E . . European Network of Transmission System Operators for Electricity
EPEC . . . . Equilibrium Problem with Equilibrium Constraints

EPR . . . . . European Pressurized Water Reactor
EU . . . . . European Union
EU ETS . . . European Union Emission Trading Scheme
EV . . . . . Electric Vehicle
FBMC . . . . Flow-Based Market Coupling
FCR . . . . . Frequency Containment Reserve
FLH . . . . . Full Load Hours
FRR . . . . . Frequency Restoration Reserve
g . . . . . Gram
G2V . . . . . Grid-to-Vehicle
GAMS . . . . General Algebraic Modeling System
GHG . . . . . Greenhouse Gas
GW . . . . . Gigawatt
h . . . . . Hours
HVAC . . . . High-Voltage Alternating Current
HVDC . . . . High-Voltage Direct Current
IC . . . . . Interconnector
IEM . . . . . Internal Energy Market
IGCC . . . . . International Grid Control Cooperation
KKT . . . . . Karush-Kuhn-Tucker
kW . . . . . Kilowatt
kWh . . . . . Kilowatt-hours
LIMES . . . . Long-term Investment Model for the Electricity Sector
LP . . . . . Linear Program
MCP . . . . . Mixed Complementarity Problem
mFRR . . . . Manual Frequency Restoration Reserve
MILP . . . . . Mixed Integer Linear Program
MPEC . . . . Mathematical Problem with Equilibrium Constraints
MW . . . . . Megawatt
MWh . . . . . Megawatt-hours
NC EB . . . . Network Code on Electricity Balancing
NEP . . . . . Grid Development Plan (German: Netzentwicklungsplan)
NO_x . . . . . Nitrogen Oxides
NRA . . . . . National Regulatory Authority
NREAP . . . National Renewable Energy Action Plan
NTC . . . . . Net Transfer Capacity
NUTS . . . . Nomenclature des unités territoriales statistiques
O&M . . . . . Operation and Maintenance
OCGT . . . . Open Cycle Gas Turbine

PC . . . . . Primary Control
PHEV . . . . Plug-in Hybrid Electric Vehicle
PRIMES . . . Price-Induced Market Equilibrium System
PRL . . . . . Primary Balancing Power (Primärregelleistung)
PSP . . . . . Pumped Storage Plant
PTDF . . . . Power Transfer Distribution Factor
PV . . . . . Photovoltaic
QCP . . . . . Quadratically Constrained Program
REEV . . . . Range Extender Electric Vehicle
RES . . . . . Renewable energy sources
RoR . . . . . Run-of-River Power Plants
RR . . . . . Replacement Reserve
SC . . . . . Secondary Control
SCADA . . . Supervisory Control and Data Acquisition
SO_2 . . . . . Sulfur Dioxide
SOAF . . . . Scenario Outlook and Adequacy Forecast
SRL . . . . . Secondary Balancing Power (Sekundärregelleistung)
TC . . . . . Tertiary Control
TEP . . . . . Transmission Expansion Planning
TERRE . . . Trans European Replacement Reserves Exchange
TRL . . . . . Tertiary Balancing Power (Tertiärregelleistung)
TSO . . . . . Transmission System Operator
TWh . . . . . Terawatt-hours
TYNDP . . . Ten-Year Network Development Plan
U.S. . . . . United States of America
UCM . . . . . Unit Commitment Model
UK . . . . . United Kingdom
V2G . . . . . Vehicle-to-Grid
VRE . . . . . Variable Renewable Energy sources
WTP . . . . . Willingness-To-Pay

Chapter 1

Introduction

1.1. Motivation

During my time as a student at the TU Dresden, I was fascinated by the vision of a large high-voltage direct current (HVDC) transmission grid spanning across Europe, northern parts of Africa, and the Middle East, providing cheap, emission-free, and reliable electricity from renewables spread across the entire region. Although renewable infeed would generally be intermittent, enough capacity – wind, solar photovoltaic (PV), or concentrated solar power (CSP) – would be available "somewhere" in the system, and thermal and chemical storage built into CSP plants would provide enough firm capacity throughout the day and night.

The opportunity to analyze the development of a potential future scenario in conjunction with an overlay HVDC grid based on such a scenario, sometimes called the "Desertec" concept, as part of a study project (Egerer et al., 2009) at the university's chair of Energy Economics sparked my interest to continue doing research in this area. The project concluded in recommending substantial investments into HVDC grid capacities leading from Morocco, Algeria and the Middle east towards central European demand centers. This vision, while at the time looking from our point of view generally somewhat realistic, did not take into account many distributional aspects and local stakeholders' interests, challenges of technical implementation, or regulatory barriers, which could potentially hinder fast realization. A combination of these aspects, in turn, contributed to a deceleration of the Desertec idea's real-world implementation. At the time I wrote my diploma thesis, the Tōhoku earthquake and tsunami in Japan and the following accident in the Fukushima Daiichi Nuclear Power Plant occurred, which influenced the decision to pursue further research into the field of sustainable electricity sector developments, as this event and the subsequent nuclear phaseout decision of the German government were further nails in the coffin of the future of nuclear power.

Before becoming active in this field, I often assumed that the transformation from fossil fuels to low-carbon technologies would proceed on its own, as the alleged scarcity of natural gas, oil, and hard coal would lead to the need to find substitutes for these fossil fuels automatically. This scarcity has turned out not to be a driving factor. In contrast, it is the amount of greenhouse gas (GHG) that can be emitted into the earth's atmosphere without causing a noticeable rise in overall temperature. There exists consensus among climate and energy researchers that carbon dioxide (CO_2) emissions by human activities and the associated external effects are one of the main drivers for climate transformation. In order to prevent the negative effects of this "market failure" (Stern, 2007) – climate change with possibly severe negative effects – the amount of future GHG emissions should be limited to keep the concentration of CO_2 in the atmosphere below 450 ppm. (IPCC, 2014; Stern, 2007)

Today, the discussion about future options for a sustainable development of the electricity sector is embedded in a broader context and part of an effort to achieve sustainable development in many sectors and areas. The target of reducing the human-induced GHG emissions to keep the rise of the global average temperature below 2 °C or even 1.5 °C above pre-industrial temperatures is consensus within the majority of the climate and energy researching community (see IPCC, 2014). To mitigate the climate transformation, the international community has adopted and ratified several international agreements such as the Kyoto Protocol (concluded in 1997, in effect 2005), and in 2015 the "Paris Agreement" (UNFCCC, 2015). Reaching these targets, as well as providing solutions that enable successful accomplishment, poses academic, technical, legal, institutional, and economical challenges, that need to be taken into account globally.

With regards to the electricity sector, this target mostly affects CO_2 emissions. This leads to a need to transform the sector from the "Old World" of mostly fossil and nuclear based electricity generation to the "New World" which relies on a combination of renewable electricity generation, storage and demand flexibility to satisfy the traditional electricity demand as well as to include interactions with new participants and sectors.

This overarching target is reflected in many European and national targets. The European Commission (EC)'s 20-20-20 goals (EC, 2008a) set targets that should be reached by 2020 (based on levels of 1990): a 20% decrease in GHG emissions, reaching an overall 20% renewable energy supply in Europe, and a 20% improvement of energy efficiency. Long term targets until 2050 are described in the 2011 *Energy Roadmap 2050* (EC, 2011b), which foresees an overall decarbonization by 80% to 95% until 2050. These targets are updated for 2030 (EC, 2014a, p. 18), where a 40% GHG emission reduction and a share of renewable energy generation of 27% is aimed for. The electricity sector is envisaged to take a lead role in overall decarbonization, as the potential for cost-effective decarbonization is greatest among the GHG-emitting sectors. The EC describes a decarbonization pathway towards at least 80% emission reduction by 2050 in *A Roadmap for moving to a competitive low carbon economy in 2050* (EC, 2011a), as shown in Figure 1.1. As the electricity sector is oriented to lead the decarbonization, an option for achieving overall reduction targets is increased interconnection with other sectors, such as the transport sector. Electrification of previously fossil fueled transportation method is expected to contribute substantially.

The energy and electricity supply infrastructure provide distinct challenges in planning the boundary conditions the system will operate within, due to the non-storability of electricity and the physical requirement that supply and demand equal each other at every point in time. At the same time, the high capital-intensity of the generation and transmission infrastructure requirements lead to long usage times, so

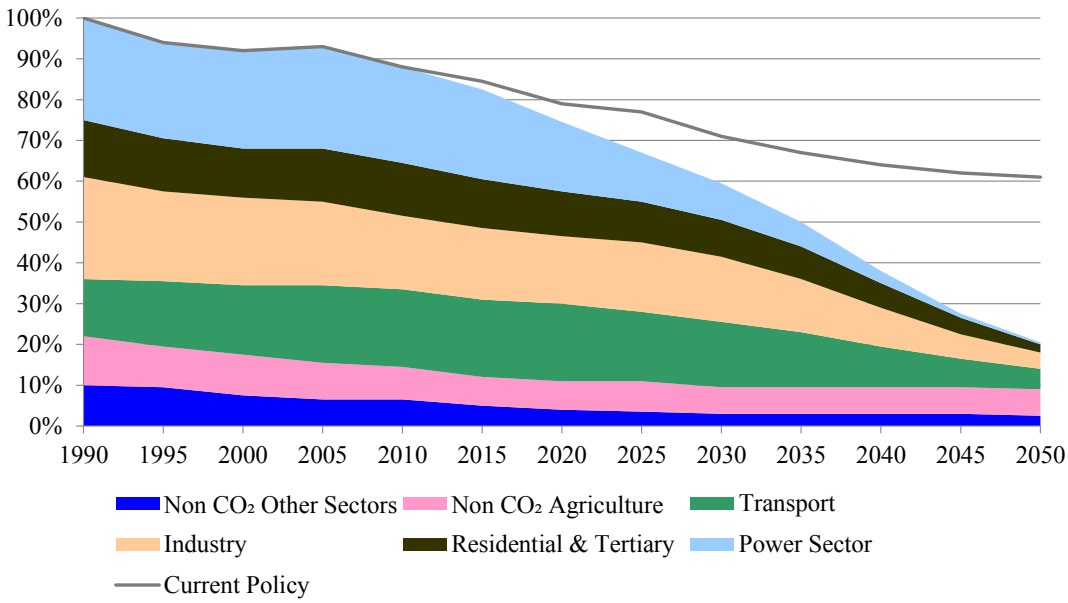


Figure 1.1.: EU GHG emissions towards an 80% domestic reduction (100%=1990) Source: Own depiction based on EC (2011a, p. 5).

that investments into conventional generation capacities usually last for two or more decades (see Markewitz, 2016). This requires a planning strategy with the long-term targets and horizon in mind and to anticipate path dependencies in the energy system (Fouquet, 2016).

The framework development for this transformation started in form of the market liberalization of the electricity sector. The transmission and generation were unbundled if previously vertically integrated; and guidelines for the internal energy market (IEM) were published. The IEM regulates both physical and market based rules. It reforms regulatory oversight, market access rules, cooperation between regulatory authorities and e.g. the process to establish Ten-Year Network Development Plans (TYNDPs) for gas and electricity (EC, 2003a,c, 2009c, 2012b, 1996). The electricity plan is drafted by the European Network of Transmission System Operators for Electricity (ENTSO-E) (formed in 1999) every two years. The TYNDP is then reviewed by the Agency for the Cooperation of Energy Regulators (ACER), the European body coordination the work of National Regulatory Authorities (NRAs).

Not only European targets exist, national goals augment the landscape of renewables and efficiency targets. Each country has a different starting point in the current CO_2 intensity of electricity generation, demand structure, potentials and renewable availabilities, and corresponding costs for investments into generation and the electricity grid. Energy policy has been subject to local influences and is nationally decided. This leads to national targets for each state, in the form of National Renewable Energy Action Plans (NREAPs), that provide the basis for national

policies. For example, Germany is aiming for a steady decline in CO_2 emissions (base 1990): by 2020 -40%, by 2030 -55%, by 2040 -70%, and by 2050 -80% to -95%. The progress and targets are tracked in yearly monitoring reports of the energiewende (BMWi, 2016, p. 5). These emission targets also translate into targets for the share of renewable electricity generation, reaching at least 80% in 2050. In the currently discussed climate plan *Klimaschutzplan 2050 – Klimaschutzpolitische Grundsätze und Ziele der Bundesregierung* (BMUB, 2016, p. 26) the decarbonization targets (base 1990) are tightened by 2030: 61-62% in the electricity sector, with an overall emissions target of 55-56%. Glachant and Ruester (2014) argue that a fragmentation risk exists, if national policies are not adequately coordinated.

Cost-effective low carbon transformation of the electricity sector implies the need for substantial changes in many parts of the system, both on a technical as well as institutional level, and regards planning and operational aspects. Some of the implications and research questions spanning from the composition of market participants, grid issues, and possible electricity generation portfolio pathways are discussed in this thesis.

1.2. Research questions and outline

The transformation challenges lead to a multitude of questions that can not only be answered from a single perspective, but engineering, economic, social, regulators and institutional aspects need to be considered. This thesis focuses on a selection of questions from operational and regulatory market environments, as well as grid and generation infrastructural perspectives, that can be grouped into three general ideas.

First, the low carbon development will lead to structural changes not only in the transmission infrastructure, but also the number and distribution of market participants in the different markets will likely increase. On the one hand, already existing technologies such as renewables will not only produce electricity but also provide further services in the electricity markets. The effect of renewables, especially wind, in providing positive and negative balancing capacity is analyzed in Chapter 2. On the other hand, increased sector interactions – in the case of Chapter 4 electric vehicles (EVs) – need to be taken into account when planning an electricity system. How different operational boundaries e.g. charging operation of EVs will influence the power plant dispatch and the resulting carbon intensity of electricity supply.

As physical and operational coordination between price zones and countries are likely to increase as part of the IEM, a harmonization of not only the spot markets but also the balancing markets is aimed for. Here the potential for increased coordination in procuring and activation of balancing reserved is analyzed in Chapter 3.

The second part deals with infrastructural issues regarding the electricity grid, and its development in Germany and Europe. The Chapter 6 follows up on the question of cross-border coordination. Cross-border interconnectors can be done either regulated, or an exemption from the regulation for merchant investors can be applied for, which the EC has become increasingly reluctant to grant. The Chapter 6 estimates the effect of allowing merchant interconnectors in the Baltic Sea region.

Chapter 5 gives an overview of the the German high voltage electricity grid development. Chapter 7 highlights cost efficient investments into European high-voltage alternating current (HVAC) or HVDC transmission capacities depending on surrounding conditions such as the chosen generation portfolio until 2050.

The third and last part deals with an integrated perspective of investments into generation as well as transmission capacities on a country level and corresponding development pathways. Chapter 8 lays the foundation by describing the to-be-applied investment and dispatch model, followed by an application. Further analysis of foresight and path dependencies is done in Chapter 9.

The research questions can thus be grouped into two general questions:

1. Assuming a change of composition and increased number of market participants: What are possible effect on the balancing market organization regarding participation of renewables and cross-border coordination; and what are the effects of an uptake of electromobility on the power plant dispatch?

2. What are effects of changes in boundary conditions on infrastructure development with regards to cross-border interconnectors, the overall HVAC or HVDC grid, and the generation and storage infrastructure until 2050?

1.3. Options for generation and transmission infrastructure investments

Electricity generation and transmission infrastructure is characterized by long lifetimes and, especially in the case of large-scale investments, by lumpiness with a high share of investment cost compared to variable and operational costs. Planning and investment thus need to take into account the longevity and sometimes irreversibility of decisions. Also, the high capital intensity and usage structure lent itself to the establishment of natural monopolies especially in the development of the transmission infrastructure over time. Parallel to this development, the large-scale electricity generation infrastructure shaped the development of the transmission grid.

Today's planning and infrastructure development methods do not only need to provide a cost efficient and reliable system, but also take into account further targets such as enabling the reduction of the system's carbon-intensity.

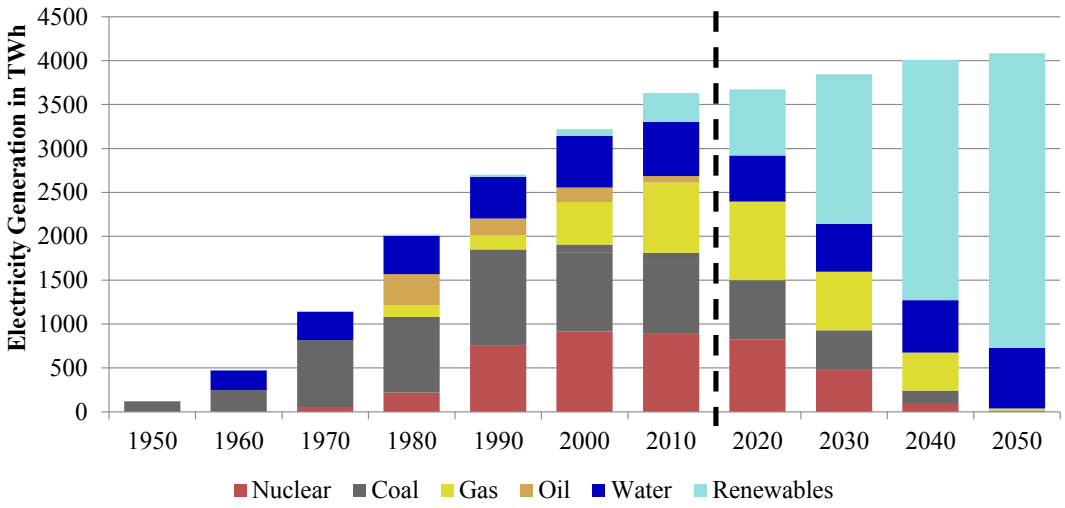


Figure 1.2.: Electricity generation in Europe since 1950.
Sources: Jahrbuch des deutschen Bergbaus 1957, Jahrbuch des deutschen Bergbaus 1961, IEA, EIA, The World Bank Development Indicators, EC Reference Scenario for Nuclear, Own calculations using the model dynELMOD for 2020 – 2050 (see Chapter 8). The definition of Europe has evolved to include more countries over time.

The low-carbon transformation of the electricity sector is influenced by many ongoing trends, such as an increasing importance of flexibility requirements both in generation, as well as demand and storage, as well as distributed in-feed of renewables. The overall level of electricity demand in Europe has increased until about 2010, and remained stagnant in the current decade (Figure 1.2). The influence of increased interconnection with other previously unconnected sectors such as heat or electromobility will likely lead to a substantial increase of overall electricity demand, that needs to be satisfied with the targets outlined above in mind. Infrastructure planning under a myopic horizon also leads to a risk of stranded assets. The policy conditions thus need to guide infrastructure investments and the energy mix, to avoid or minimize the risk of investments that prove to be unnecessary in hindsight.

1.3.1. Capacity development in Europe

Figure 1.2 shows the development of the generation mix in Europe starting in 1950. The main fuel is hard coal, followed by natural gas and oil. Nuclear energy starts to become a significant electricity generation technology starting in the 1970s until reaching a peak share in the 2000s of over 25%. The generation from water is the most constant over time, as here potentials were accessed early.

Renewables (other than Hydro) start to achieve a relevant share in the 2000s, which will likely increase in the coming decades. Figure 1.3 shows a more detailed picture of generation from Biomass, Wind, Solar PV, and other renewable sources for the years 1990 to 2012. Values for years beyond 2010 in Figure 1.2 are based on

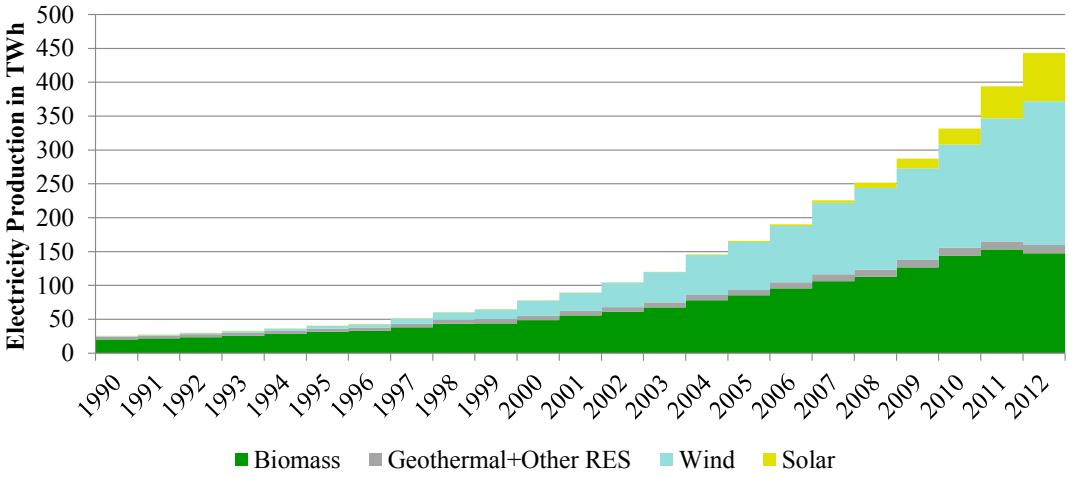


Figure 1.3.: Development of renewable energies in Europe 1990-2012 (without hydro) Source IEA Statistics

model results from Chapter 8. Here, renewables dominate the energy mix, driven by investment cost decreases as well as the emissions targets.

1.3.2. Technology choice

Today's most promising technologies to support the low-carbon transformation of the electricity sector and to meet the emission targets are onshore and offshore wind turbines, Solar PV, CSP, and the use of biomass. A strong decrease in investment cost, combined with subsidy schemes such as the German Renewable Energy Sources Act (EEG, Erneuerbare-Energien-Gesetz) in 2000 (which replaced the Stromeinspeisungsgesetz "Act on the Sale of Electricity to the Grid" from 1990, and also contributed to the overall investment cost decrease) lead to worldwide investments into these technologies being more than twice as high than into technologies using fossil fuels (BMWi, 2017, p. 17). While hydro power also counts as a renewable electricity source, the future expansion potential seems to prevent significant growth in the near future. Especially the cost decrease of solar PV has outperformed most estimates, the cost decrease for onshore wind has been less prevalent.

The nuclear power plant fleet in Europe is also likely to undergo substantial change in the coming decade. In some countries construction of new power plants is not considered an option and the power plant fleet is shut down in the coming years as part of a nuclear phaseout. In countries such as France or Finland, a large percentage of the existing nuclear power plants are approaching the end of their lifetime. While the construction and operation and maintenance (O&M) cost of renewable electricity sources have decreased over the last years, nuclear power has shown an opposing trend. Here, the construction cost have risen over time and are unlikely to profit

from n^{th} of a kind cost decreases (Grubler, 2010). The cost development and other obstacles in building the latest generation of reactors the European Pressurized Water Reactor (EPR) in Flamanville, France, or Olkiluoto, Finland, either prevents further plans for construction, or requires substantial subsidies to be considered an option as is the case in the construction project for the Hinkley Point C nuclear power station in the United Kingdom. Further, the true "cost" of implementing nuclear generation capacities are often underestimated as the dismantling and decommissioning and storage of nuclear waste have proven to be great unknowns. While for dismantling and decommissioning cost estimates exist, the lack of long-term storage facilities for highly radioactive waste prevents useful cost estimates in most countries. Thus, nuclear power is unlikely to see a revival, as the high costs combined with the question of waste storage and the associated external effects do not show bright prospects (see Schneider et al., 2016).

Fossil fuels do not contribute to a low-carbon electricity system, but during the transformation, gas could potentially function as a bridge technology. The role of hard coal in the future of a decarbonized energy system is often discussed in conjunction with carbon capture, transport and storage (CCTS) with two main applications in mind. First, application of CCTS in the energy sector used to be considered as an option for decarbonizing the supply of electricity with a high firm capacity. Today's discussion has shifted to a combination of renewables and storage, as no large scale application of CCTS have emerged and the technology will likely not be competitive against renewables if available. Second, the discussion focuses on application of CCTS in industrial applications, as some industrial processes emit large amounts of CO_2, although – besides uncertain availability and economic feasibility – also opposition from the public exists. (see Oei et al., 2014).

In large scale electricity or energy sector analyses, CCTS is often still considered as an option (IPCC, 2014), as the combination of using bio-fuels and CCTS could lead to calculative negative emissions which are assumed to be required depending on the speed of transformation or the inability of other sectors. Thus, the European Commission's *EU Reference Scenario 2016: Energy, transport and GHG emissions – Trends to 2050* assumes a combination of renewables, CCTS, and fossil fuels in European electricity supply until 2050, with 19 GW of CCTS capacities in Europe in 2050 (EC, 2016, p. 140).

1.3.3. Flexibility requirements and interdepencencies increase

Daily and seasonal feed-in patterns of renewables provide further challenges, as their output is characterized by constant variations in output depending on local wind or sun availability. This stochastic feed-in, as well as the spatial potential

distribution and temporal correlation of e.g. solar PV feed-in with demand, can not solely provide firm capacities for an adequate power supply. Thus chemical, mechanical, or physical storage capacities, such as pumped hydro, compressed air energy storage, or battery capacities need to augment the renewable operation for the successful operation of the electricity system. Today's market setup does not yet favor the implementation of large scale storage applications. The conclusions from Zerrahn and Schill (2015a), as well as the results from Chapter 8, show that the need for large scale storage is moderate until high shares of renewable electricity generation have been achieved. Also current market prices, as well as market price variations do not necessarily favor large-scale investments with the exception of balancing services, where battery based storage systems have been successfully deployed to participate in balancing markets. With the continuing faster-than-anticipated cost decrease of storage capacities, (prosumage-) applications at end-users houses with own (mostly solar) generation have gained traction in order to increase the self-consumption ratio of their own generation (see Schill et al., 2017). Assuming an adequate market environment, large scale adoption of storages in conjunction with renewables can also be expected (Vaeck, 2014).

Assuming a constant or falling demand for electricity for today's applications induced by energy efficiency measures, increased interaction with other sectors will shape the future of electricity generation, both in terms of overall volume as well as daily and seasonal patterns of demand. Increased coupling between the heat, transportation, and the electricity sectors is likely a necessity for meeting the decarbonization targets set by the EC and nationally. The use of battery-electric vehicles (BEVs) in the transportation sector will increase as battery prices continue to decrease and the EV technology matures.

This development is further accelerated by the introduction of national subsidy and promotion schemes, to increase the rate of adoption for electric vehicles. For example, the German government's plan is to reach one million EVs by the year 2020. Special allowances and subsidy schemes for the use of EVs are expected to drive demand to reach these targets. While meeting the targets mentioned above is unlikely from today's standpoint, as in 2015 41,460 BEVs were registered in Germany (BMWi, 2017, p. 11), a rising share of electric vehicles over the next decades can be assumed.

With the uptake of electromobility in Europe the increased electricity demand and associated charging strategies affect not only the total demand, but the temporal distribution of the load increase affects the power plant dispatch. As long as under-utilized fossil power plant capacities are present in the electricity system the additional electricity demand can lead to an increase in total carbon intensity of electricity generation (Chapter 4). Therefore the combination of supporting transport

electrification as well as additional renewable capacity deployment to account for the uptake in electricity demand could mitigate potential negative impacts on the carbon intensity of the system as a whole. Furthermore, if technical as well as regulatory challenges are overcome, EVs could also contribute to overall system stability and provide system services such as balancing reserves.

The currently high carbon intensity of the heat sector also needs to be reduced, here the application of electric heating (given a relatively carbon-free electricity mix) or reduction of demand are viable options, accompanied with an uptake in the use of heat-pumps and better building insulation or other energy efficiency measures, especially in industrial applications. This leads to an increase in overall electricity demand, accompanied by a change in seasonal and temporal demand structure and availability of demand flexibility options (Agora Energiewende, 2015; Quaschning, 2016). The demand patterns could vary significantly, e.g. depending on the charging strategy of BEVs, or outside temperatures and seasonal patterns.

The increased coupling of sectors could also play a significant role in providing flexibility in the system, by using demand side management (DSM) measures to shift demand patterns to times of low demand or high renewable in-feed, thus reducing the need for storage operations by demand side flexibility. However, there exists a high degree of uncertainty about the total demand increase in the future depending on the rate of sector coupling over time.

1.4. Boundary conditions for efficient operation

As shown above, (long term infrastructure) planning of the electricity system must be done to achieve an overall framework that enables the operation of the system to be able to reach the goals specified at the outset.

For example, the EC's efforts to foster the implementation of the European IEM affects both market design as well as infrastructural issues. Increasing cross-border interconnection not only helps to increase the system adequacy, but also allows for more market interaction. Today's cross-border coordination on the electricity spot markets is joined by other forms of cross-border cooperation such as the balancing reserve markets, congestion management, or the introduction of flow-based market coupling (FBMC) in the Central Western Europe (CWE) region.

This has also lead to an increase of planning complexity over time, as e.g. in the case of cross-border cooperation many institutions such as the EC, the ACER, the transmission system operators (TSOs), their respective national regulatory authorities as well as other stakeholders are involved in the discussion. Schmid et al. (2016) illustrate the entanglement of actors and institutions at the example of the German energiewende.

The composition of the future electricity mix and transmission lead to a change in participant structure, which depends on the boundary conditions given. Furthermore, in order to enable a cost-efficient and adequate environment, some market and interaction rules might need to be adjusted to the new and evolving boundary conditions. Examples could be the governance and regulation on balancing reserve markets, the setup and sizing of price zones, the fostering of regional cooperation on market aspects, and other changes in market design to provide regulatory and technical boundary conditions enabling the transformation towards a renewables-based energy supply across sectors.

In this thesis, three aspects are highlighted. First, incorporating new market participants: the uptake of electromobility, as well as potential changes in the rules of participation in balancing reserve markets for renewables are analyzed. Second, options for increased cooperation across borders in procurement and activation of balancing reserves are considered. And third, exempting an investor from some regulations in building a specific cross-border interconnector in return for achieving improved cross-border interconnection is analyzed.

1.4.1. Changes in balancing markets environments

Balancing reserves are an instrument that is used to even out short term system imbalances from the nominal alternating current (AC) frequency of 50 Hz. Balancing reserve markets are mostly nationally organized, as slight implementation differences have prevented consolidation in the past, and as today's other market segments have been organized without the notion of short-term or real time demand fluctuation. Some elements of the system need to mitigate shortest deviations in the system frequency to ensure overall stability. In general, balancing reserve is usually are organized using three different product types, depending on the speed of activation and procurement areas. When a deviation occurs, the "fastest" reserve, the frequency containment reserve (FCR) is activated, triggered by the system frequency. When the system's frequency is below 49.99 Hz or above 50.01 Hz, upward or downward regulation is provided. The reserve with the second fastest response time the frequency restoration reserve (FRR) is activated after a deviation longer than 30 s. It is activated automatically or manually, depending on the control zone's setup. In case a deviation longer than 15 min takes place, the replacement reserve (RR) is activated.

About 3,000 MW of FCR capacity are procured in the Central European (UCTE) Grid. In central Europe, the markets for FCR are organized nationally, but as the activation of the reserves depends on the overall system's frequency, which is the same in the entire grid, the activation occurs on a pro rata basis for each market participant. Thus, joined procurement efforts across control zones have been implemented in

the German, Belgian, Dutch, French, Swiss and Austrian markets, starting with joint procurement between Swissgrid and the German TSOs in 2012. In Germany, the procurement only takes into account the capacity costs per megawatt (MW), the energy supplied or reduced is not reimbursed. For FRR and RR, the current procurement procedure relies on a two-stage process, where pre-qualified market participants bid a reservation price (in € per MW) as well as an activation price (in € per MWh). The prices paid by the TSOs are pay-as-bid. In other countries, the bidding and payment procedures differ slightly. The ENTSO-E aims to also allow for a common merit order priced balancing reserve activation on order to increase market liquidity and allow more flexibility options to participate in the market as part of their balancing market harmonization efforts. Depending on the control zone's market setup, the activation of the FRR takes place evenly, or based using a predetermined merit order list. The markets for FRR and RR are mostly nationally organized, with increasing cross-border cooperation arrangements such as the International Grid Control Cooperation (IGCC), and other ongoing pilot projects that promise overall efficiency increases and lower procurement and activation cost by reaping existing potentials of cooperation.

Due to potentially higher in-feed fluctuations of renewables, current literature finds an expected reserve increase of 2 % to 9 % of additional wind power capacity (see the overview Hirth and Ziegenhagen, 2015). If solar PV is also added simultaneously, the additional reserve demand is estimated to be slightly lower. Contrary to these findings, and while renewable capacity has increased substantially in recent years, the absolute reserved balancing capacity has decreased in the years 2010–2015.

At the same time, renewables – especially wind turbines – are expected to be able to provide balancing services. Assuming a pool size large enough to mitigate short-term calms, in conjunction with a market setting enabling the participation, renewables can provide negative balancing services by offering a percentage of their capacity on the balancing market without negatively affecting their standard operation (Sorknæs et al., 2013). Further along in a system with a very high share of renewables, the electricity and storage demand could be surpassed by renewable availability. In this setting, offering positive balancing services by balancing services also becomes a realistic scenario.

1.4.2. Cooperation in balancing and transmission expansion

System flexibility can be provided by supply and demand, increasing cross-border interaction both on an infrastructural as well as operational level. Increased connection and cooperation can help to reap potential of different generation and storage portfolios as well as renewable availability and demand patterns. This applies both

to conventional and renewable generation technologies, which are exposed to a larger market. By competing with each other the average electricity price might decrease. In turn, also the short term demand or in-feed fluctuation can be evened out in a well interconnected system, leading to an increase in the use of renewable capacity even in times of high in-feed and giving the system more flexibility. Increasing interconnection and coordination is one of the targets in European energy policy, such as establishing the IEM.

Distributional aspects of increasing cooperation need to be taken into account. While cooperation generally leads to an increase in overall system efficiency and lower cost, some participants might be disadvantaged and therefore not willing to commit to cooperating Egerer et al. (see 2015a). Thus, compensation mechanisms can be an option to enable cooperation.

In this thesis, regional cooperation both on the balancing markets as well as grid expansion is analyzed. Further aspects of cross-border coordination such as cross-border congestion management, coordinated transmission planning using a common grid model, or the introduction of FBMC (which is already in place in the CWE region) is not analyzed in detail. See Kunz and Zerrahn (2015) for an analysis of FBMC and cross-border congestion management.

Cross-border balancing cooperation

Most balancing markets are organized on a national level, with slightly different implementations. Thus, several different levels of cross-border cooperation could be implemented. Each level of cooperation has distinct technical or institutional challenges. The most simple form of cooperation is the so-called "imbalance netting," where counter-activation of balancing reserves is avoided by taking the balancing demand of neighboring control zones into account during activation. The second form of cooperation is cross-border activation, where (given free cross-border transmission capacities) the TSOs use a joint merit order curve for balancing reserve activation. The highest degree of coordination is joint procurement of balancing reserves. This not only requires a joint procurement platform and compatible balancing products, but also the assignment of specific cross-border capacities for balancing capacity, which could potentially interfere with the spot and real-time markets.

The potentials and benefits of cooperation on balancing reserve markets have been recognized by the TSOs and the ENTSO-E. One example of a successful cooperation scheme on the balancing markets is the IGCC, where imbalance netting to avoid counteractivation between control zones is implemented. Starting with a cooperation of the four German TSOs in 2012, the IGCC has been joined by the majority of neighboring TSOs. To enable harmonization, implementation guidelines and network

codes such as the Network Code on Electricity Balancing (NC EB) have been drafted, which provides a framework for future balancing harmonization by establishing common rules for imbalance settlement, procurement, and cross-zonal reservation. The current draft is expected to be adopted by the end of 2017 (EC, 2017).

Regional cooperation in interconnector expansion

On the physical level, cooperation is achieved using transmission grid infrastructure, through which the markets are interlinked. The need for increasing investments into cross-border grid capacities is expressed in many transmission expansion plans such as the TYNDP, which is updated on a regular basis every two years. An example for a regional cooperation agreement is the Baltic Energy Market Interconnection Plan (BEMIP) (EC, 2009a), which besides increase market interconnection also focuses on the transmission grid infrastructure.

Most cross-border transmission infrastructure investments are conducted by TSOs, who operate within the bounds of their respective regulatory environment. A potential option to enable additional investments into cross-border transmission infrastructure is allowing "market"-driven transmission investment in form of so-called merchant investments. This type of investment is possible within the current legal and institutional framework, but needs approval from the EC by granting an exemption from regulation such as third party access. These investments are financed by the earnings of operating the cross-border line, e.g. the arbitrage between the electricity prices in the interconnected price zones. In the European Union (EU) merchant investments have not played a significant role, and the EC has become reluctant to grant exemptions (Cuomo and Glachant, 2012), as the multitude of currently existing interconnection projects as well as the divergent goals of profit-maximizing investors and "welfare-maximizing" or "cost minimizing" regulators have led the EC to not needing to grant exemptions.

1.5. Modeling the electricity sector

Most of this thesis' chapters analyze aspects mentioned previously with the help of quantitative electricity sector models applying concepts from operations research. An appropriate model setup needs to be applied in order to be able to answer the question asked. In the literature and in practice, a wide range of energy system and electricity sector models exist. Energy system models include a representation of many aspects and interaction between sectors and fuels, whereas electricity sector models focus on certain aspects in electricity production, transmission and consumption.

The quantitative approach allows to be able to determine in the influence of policies applied, or estimate the effect of the variance of boundary conditions. In this thesis, various fundamental partial equilibrium models are applied. The purpose of using mathematical models applied to the electricity sector is often the pursuit to answer a specific range of questions. Each approach differs slightly, which results in different model specifications and characteristics.

As is the case with all models regardless of model specification, they represent a snapshot of the currently prevailing settings and assumptions about possible future development options. Possibly new developments or unexpected technological advancements cannot be represented. Thus, all results regarding future development represent a possible pathway, not a "prediction" per se. As Richard Hamming (1962, p. vii) states: "The purpose of computing is insight, not numbers." Not the absolute values, but rather the interactions, sensitivities, and interdependencies are of importance, as they help gain a deeper understanding of the relevance of the models' results.

1.5.1. Model types

Using a classification scheme by Ventosa et al. (2005), each model falls into one of three categories: 1) single firm, 2) market equilibrium models considering all firms, and 3) simulation models. Single firm models focus on a specific topic with a high degree of detail such as power plant dispatch, but do not take interactions with other market participants into account.

Market equilibrium models can also be called partial equilibrium models. They focus on a specific sector or commodity. Here, not the entire market but only a cutout is modeled in detail. In the case of the electricity sector the focus lies on supply, market clearing via transmission or markets, storage, and demand (and DSM). Other boundary conditions such as the price for fuels is usually assumed as inelastic even in long-term applications, although in a real world setting interdependencies exist. This allows for a fine-grained representation of features relevant to the research subject to gain insights into specific aspects. Applications can achieve a detailed representation of a special set, e.g. high time resolution of covering a long time horizon for dispatch or a long time horizon for the overall development of the sector.

Often used approaches in electricity sector models are linear programs (LPs). Here a cost-minimization approach represents the assumptions of perfect competition between all market participants. Interaction between the players happens using a market clearing equation. When binary decisions such as the on/off status of a power plant or integer decision variable are required, mixed integer linear programs (MILPs) are used. The solution approach can be significantly more complex than

in a LP approach, as the combination of continuous and integer variables requires combinatorial optimization methods such as branch and bound or branch and cut. In the case of a welfare maximization approach the objective function becomes nonlinear and a quadratically constrained program (QCP) is used. It allows for quadratic objective functions or (convex) quadratic constraints. LP, MILP, and QCP type models can be solved efficiently using commercial solvers such as CPLEX or GUROBI.

Modeling strategic behavior of one or more market participants has become an important strand in the modeling world. For non-cooperative single level games, where all participants act simultaneously, mixed complementarity problems (MCPs) can be used. Example applications are oligopolistic settings with Cournot or Bertrand competition. Bi-level equilibrium problems can be used to combine two separate optimization problems. This is often the case when strategic behavior of market participants is assumed (leader), whereas other market participants (followers) react to the decision of the leader. In this Stackelberg setting mathematical problems with equilibrium constraints (MPECs) are used when the relationship between leaders and followers is 1 to n. With n leaders and m followers, the model becomes an equilibrium problems with equilibrium constraints (EPEC).

The third category in the classification by Ventosa et al. (2005) are simulation models. For example Mantzos and Wiesenthal (2016) and Wiese et al. (2014) have developed the simulation models POTENCIA and renpass for future scenarios for power system developments in Europe. These models do not rely on the optimization of a single or multiple objective values, but determine the interaction of each market participant "agent" based on predetermined algorithms. As no formal optimization problem is solved, these heuristics can be highly nonlinear and change parameters over time. As all player's behavior is defined by the algorithm, convergence or optimality can not be guaranteed. This gives the opportunity to implement complex interaction relationships, as well as the option of learning from the effect of each actor's past decisions.

Another strand of models relies on evolutionary (or genetic) algorithms to solve large scale problems efficiently without having to resort to an integrated optimization problem. Bussar et al. (2016) apply a capacity planning model using an evolutionary algorithm, that iteratively determines power plant investments in the European electricity sector of 2050.

1.5.2. Trend to open source models and data

With more and more computational capacities and advances in solution algorithms available, the models do not only become more complex to still be at the edge of

computability within reasonable time frames, but also input data requirements rise considerably.

Transparency about the model as well as the the input data used is required for scientific credibility. Furthermore, there is an ongoing trend to publish the data and models under an open source license. Pfenninger (2017) argues, that only if the model itself as well as the data used is available, model results can be validated and trusted.

Notable examples of data or model publications under an open license can be found in Abrell and Kunz (2015), Bussar et al. (2016), Egerer (2016), Howells et al. (2011), SciGRID (2017), Wiese et al. (2014), and Zerrahn and Schill (2015a). Complete data sets for direct use are provided by Egerer et al. (2014) and Schröder et al. (2013a), and by research projects focusing on developing data platforms for the use in energy sector models such as "Open Power System Data (OPSD)", "Renewables.ninja", or "SciGRID" (OPSD, 2016; Pfenninger and Staffell, 2016; SciGRID, 2017; Staffell and Pfenninger, 2016). The model and data presented in Chapters 8 and 9 is also published under an open license.

1.5.3. Choosing the appropriate time horizon

The following sections will give an overview of the trade-off and modeling decisions when developing an electricity sector model. Electricity sector models can roughly be categorized in static and dynamic or planning models. Static models do not determine investments into infrastructure, whereas in planning (greenfield or brownfield) model approaches, not only the operation of the system but also the developments of parts of the infrastructure are endogenously determined. A dynamic planning model optimizes over a set of multiple investment periods while considering the investments of all previous investment periods.

Static models do not model changes in the system infrastructure but focus on a detailed power system representation, often with an emphasis on the technical system and derived flexibility of the system or representation of stochasticity. For power plant operation, constraints regarding each power plants unit commitment, minimum load, startup costs, ramping speed and cost, part load efficiency, balancing reservation, or heat delivery constraints can be represented. Some of these constraints require nonlinear (binary or integer) constraints, or are linearized. Various approaches exist that determine optimal power plant dispatch either using linear or mixed-integer formulations (Abrell and Kunz, 2015; Delarue et al., 2009; Egerer, 2016; Hobbs, 2001; Kemfert et al., 2016).

Dynamic investment planning models are applied to examine the power system development. This includes endogenous determination of capacity development possibly

over multiple investment periods. Connolly et al. (2010) and Després et al. (2015) give further overviews over long-term energy modeling tools and their applications.

1.5.4. Choosing a spatial resolution and connection between nodes

In electricity sector models, the interaction between all market participants, regardless of generation, storage, or demand is coupled using a specific market clearing mechanism. In the case of a single market, the market clearing equation can be implemented using a single equation combining all sources and sinks. As soon as either the coupling of (spatially separate) markets or an approximation of the underlying transmission grid infrastructure is to be represented, the coupling of markets and nodes needs to be taken into account.

In electricity sector models focusing on spot market results, an often used approach is coupling of markets using a transport model with net transfer capacities (NTCs). This approach mimics cross-border interaction (Nahmmacher et al., 2014; Richter, 2011). This approach has the advantage of having low data requirements and fast solution times compared to other approaches, and allows for easy implementation of investments into NTC-capacities. However, the developments on the European electricity markets have evolved, and some physical parameters of the underlying grid are now reflected in the market. In the CWE region FBMC has been introduced in 2015. Therefore new long-term models should be able to include the loop-flow nature of the meshed electricity grid infrastructure even in a zonal market setting, as otherwise an overestimation of the use of a single connection can occur, as interactions are not taken into account. Here a power transfer distribution factor (PTDF) matrix is used, that approximates the loop-flow nature of the interconnected electricity grid on a zonal basis (see Burstedde, 2013; Duthaler, 2007; Groschke et al., 2009; Liu and Gross, 2002). This approach does not represent all aspects of FBMC, as for example neither generation nor load shift keys, which approximate the effect of a change in generation or load in the underlying HVAC grid, are represented. To implement N-1 security in a line-sharp PTDF approach, J. Guo et al. (2009) present an approximation of line outage distribution factors that can be taken into account during the dispatch calculation. The applications in Chapter 8 and Hagspiel et al. (2014) approximate cross-border interaction using a PTDF matrix, which is derived from line-sharp data of the underlying electricity grid infrastructure. Investment into line capacities are represented as increases between nodes. If investments in a previously weakly connected system take place, an iteration between infrastructure investment and a recalculation of the PTDF to represent the effects of investment on the transmission network is required. In the example of the European continental grid,

the already existing grid has a high degree of interconnection. Not all publications use an iterative approach to model investments.

When modeling line-sharp electricity networks, one of the main challenges is a good approximation of the power flows in meshed grids, and respecting Kichhoff's and Ohm's laws. Due to the nonlinear and nonconvex nature of the required physical constraints and the representation of reactive power flows in addition to the real power flows, the computational complexity of an exact representation is too high for application in large scale economic optimization models. Schweppe et al. (1988) and Stigler and Todem (2005) formulate a linearized direct-current load flow (DCLF) approximation, on which Leuthold et al. (2012) have built the model ELMOD at the TU Dresden. To linearize the line flow constraints voltage angles between nodes ϕ are approximated under the assumption, that the voltage angle difference is sufficiently small, so that the $\sin(\phi)$ or $\cos(\phi)$ do not diverge far from 0 or 1 respectively. The methods and constraints used in Leuthold et al. (2012) are the basis for the application in the grid representation approach in Chapter 7. A line sharp electricity network approximation also enables a more accurate representation of investments into grid infrastructure compared to the NTC or PTDF approaches. In models that include a grid representation the "market" results are subject to the constraints imposed by the grid. Therefore this approach finds results that nodal pricing scheme would produce.

1.5.5. Modeling investments into the transmission grid

The trade-off in transmission expansion planning (TEP) applications lies between finding a congested network with a high electricity generation cost but low grid cost, and a network free of congestion but high network costs. Latorre et al. (2003) provide an overview of model types used in TEP. This section focuses on application in optimization models. "Optimal" grid investments should weigh the cost of congestion with the cost of grid to be built (Kirschen and Strbac, 2004, p. 241). Thus, temporary congestion is to be expected and the solution will converge to the optimum of interregional and local generation and associated grid cost (Midwest ISO, 2010). The problem of transmission expansion planning has existed for a long time (see Kaltenbach et al., 1970). The lumpy characteristic of line investments requires nonlinear or binary variables, as not only the expansion of single lines, but also changes in the voltage level of lines potentially need to be represented. Furthermore there exists a bi-linearity between endogenous variables for physical line parameters and for load flow. If desired, new lines between previously unconnected nodes and changes in the topology, or losses in electricity transmission could also be implemented. These non-convex constraints lead the use of MILPs in many TEP applications.

Line-sharp transmission expansion planning is implemented in the literature in various ways:

1. Modeling investments into line capacities but neglecting the change of single lines' characteristics. Depending on the context, this approach is sufficient, see Egerer and Schill (2014).

2. Using a linear relaxation as shown in Taylor and Hover (2011), allows the model to stay in a linear model space.

3. Directly as a nonlinear problem. Solving such a problem directly is only feasible for very small problems, therefore not applied widely.

4. Iteratively, as shown in Chapter 7 (Egerer et al., 2016a) or Fürsch et al. (2013). Iterative approaches profit form fast solution times, as each single optimization problem can be solved in a short amount of time. A heuristic to determine convergence of the solution is required, and optimality of the solution is not necessarily guaranteed.

5. Using a decomposition technique such as Benders' decomposition (Alguacil and Conejo, 2000; Conejo et al., 2006; Gunkel and Möst, 2014; MacRae et al., 2016) or Dantzig Wolfe (Flores-Quiroz et al., 2016). Decomposition approaches combine the iterative nature of solving many easy optimization problems and building on their solutions by adding constraints with the high likelihood of finding a solution close to the optimum.

1.6. Overview of the thesis with contributions and publications

In this thesis, models are developed and applied that either depict individual parts of the energy system in detail (such as balancing or electromobility), investments into electricity grid infrastructure, or an overview of the development of pathways and decarbonization options of the entire European electricity sector. It is divided into three parts, see Figure 1.4.

The first part deals with market developments and operational aspects in the context of the sector transformation. Chapters 2 and 3 present exercises regarding the balancing markets and presenting the model ELMOD-MIP, followed by an analysis of electromobility and power plant dispatch in Chapter 4.

The second part deals with investments into the high voltage electricity grid. Chapter 5 deals with a description of the process and role of network planning in Germany. Chapters 6 and 7 present numerical calculations, regarding the regulation

Part I: Operational and market aspects

Chapter 2: Wind providing balancing reserves in a changing generation portfolio
- What is the effect of Wind participation on the balancing market?
  Model development of ELMOD-MIP and application; joint work with Casimir Lorenz

Chapter 3: Options for cross-border balancing reserve provision
- Focus on joint procurement and activation of balancing reserves in the alpine regions
  Model extension and application; joint work with Casimir Lorenz

Chapter 4: Power system impacts of electric vehicles in Germany
- What is the effect of EV charging patterns on the power plant dispatch in Germany?
  Implementation of EV charging into a unit commitment model; joint work with Wolf-Peter Schill

Part II: Network aspects: Investments into the high voltage electricity grid

Chapter 5: The role of electricity transmission infrastructure in Germany
- Does the current speed of grid infrastructure development in Germany slow down the energiewende?
  Single author chapter, part of upcoming book „Energiewende: A Mid-Term Perspective on Electricity Sector Reform"

Chapter 6: Is There Still a Case for Merchant Interconnectors?
- Should cross border investment be regulated or merchant, what are the effects of exemptions?
  Modeling and assessment; joint work with Alexander Weber

Chapter 7: European Electricity Grid Infrastructure Expansion in a 2050 Context
- What is the effect of generation portfolio development on the need for transmission in Europe?
  Model extension of ELMOD to investments in transmission; joint work with Jonas Egerer and Casimir Lorenz

Part III: Dynamic investment perspective: Investment into generation, storage, grid

Chapter 8: A Dynamic Investment and Dispatch Model (dynELMOD)
- Model development and application to the European electricity sector
  Joint work with Casimir Lorenz

Chapter 9: Scenarios for Decarbonizing the European Electricity Sector
- Focusing on the effect of planner's foresight on generation capacity investments and stranded investments
  Joint work with Christian von Hirschhausen, Claudia Kemfert, Casimir Lorenz, and Pao-Yu Oei

Figure 1.4.: Thesis overview

of cross-border interconnectors, and the effect of generation technology choices on the need for transmission investment in Europe.

The third part combines insights of the technological and policy options by taking an integrated investment perspective on the future development of the European power sector. Chapter 8 presents the model dynELMOD and an application; Chapter 9 focuses on scenarios for the decarbonization of the European electricity sector with regards to boundary conditions such as the planners' foresight.

Chapter 2: Wind providing balancing reserves

This chapter analyzes possible price and dispatch developments in the German balancing market of 2025. As the German energy mix might change significantly in the future, the German balancing reserve markets are a good test subject to identify how the balancing reservation and activation patterns might change. On the one hand, the transformation of the generation portfolio towards fluctuating

Table 1.1.: Overview of Chapters 2–4: Pre-publications and own contribution

Chapter	**Pre-publication and own contribution**
2. Wind providing balancing reserves	This chapter is based on DIW Berlin Discussion Paper No. 1655 (Lorenz and Gerbaulet, 2017) and submitted to Applied Energy. Joint work with Casimir Lorenz. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
3. Options for cross-border balancing reserve provision	This article first appeared in Economics of Energy & Environmental Policy, Vol. 3, No. 2, pages 45-60, 2014 DOI: `http://dx.doi.org/10.5547/2160-5890.3.2.cger` - Reproduced by permission of the International Association for Energy Economics (IAEE). Previous versions were published as DIW Berlin Discussion Paper No. 1400 (Lorenz and Gerbaulet, 2014) and presented at the 14th IAEE European Energy Conference 2014 in Rome, Italy, 9th Internationale Energiewirtschaftstagung 2015 in Vienna, Austria, and the 10th Conference on Energy Economics and Technology (ENERDAY 2015), in Dresden. Joint work with Casimir Lorenz. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
4. Power system impacts of electric vehicles in Germany	This chapter is based on Applied Energy 156, 185–196 (Schill and Gerbaulet, 2015b); DIW Berlin Discussion Paper No. 1442 (Schill and Gerbaulet, 2015a). Findings and policy implications are published in the DIW Wochenbericht 10/2015 *Speicher und Elektrofahrzeuge im Stromsystem* as well as the DIW Economic Bulletin 17/2015 *Power System Impacts of Electric Vehicles.* Joint work with Wolf-Peter Schill. Clemens Gerbaulet had the lead in developing the novel implementation of user charging preference in the model and in the GAMS implementation. The writing of the manuscript was executed jointly.

renewable energy sources (RES) has progressed widely. On the other hand, not only the infrastructure itself, but the auction design will likely undergo a reformation to allow increased market harmonization with neighboring countries and enable of new market participants.

To do this, the chapter introduces the fundamental cost-minimizing electricity sector model ELMOD-MIP. The model includes unit-commitment constraints as minimum load, part-load efficiency, time-dependent start-up restrictions, complex combined heat and power (CHP) constraints and minimum bid sizes for balancing capacity reservation. Furthermore, the model features a novel approach of modeling balancing reservation by considering possible activation costs already during the

reservation phase, mimicking the activation anticipation of market participants. This also allows for the reservation as well as activation of negative balancing capacities.

In future scenarios of 2025, the influence of a changed power plant portfolio on prices and allocation of reserves is analyzed. Furthermore, the influence of wind power as a new market participant for the provision of positive and negative reserves is analyzed.

The application of scenarios of the year 2025 shows an increase of prices for positive and negative reserves, in case no new market participants enter the market. With the participation of wind turbines as a new market participant the cost for balancing provision can be reduced by up to 40 %. When wind provides both positive and negative reserves especially the high price segment will be reduced significantly. This can be reached already with a relatively low share of wind participation, where wind turbines participate with five percent of the capacity. Therefore, further fostering the process of allowing wind turbines to participate in the German reserve market seems favorable.

Chapter 3: Options for cross-border balancing reserve provision

This chapter expands the analysis of balancing markets towards different degrees of cross-border cooperation in the region of Austria, Germany, and Switzerland. The European electricity system undergoes significant changes, not only with respect to developments in generation and networks but also the arrangements for the operation of the system. These are specified in the Network Codes endorsed by regulators, network operators and the European Commission with the objective to create an "Internal Energy Market." Nevertheless, cooperation on balancing markets is still under development and not as tightly integrated as spot and forward markets. Several factors make cross-border cooperation on balancing markets complex. First, balancing products are not necessarily harmonized in each country. Second, the procurement and activation procedures are implemented differently in most countries. The NC EB by the ENTSO-E should tackle this problem by harmonizing electricity balancing rules. Its objective is to foster cross-border exchange of balancing services and in turn lower overall costs and to increase social welfare. The NC EB also arranges for regional cooperation between few parties, to speed up harmonization processes.

This chapter analyzes different forms of cross-border exchanges of balancing reserves with an application to the region of Austria, Germany, and Switzerland. Three scenarios with differing levels of cooperation are tested: *Imbalance Netting*, *Joint Activation* and *Full Cooperation*. The analysis is performed with the help of an extended version of the ELMOD-MIP described in Chapter 2. The model is extended

to be able to represent cross-border interaction and reservation and activation of balancing reserves within a multi-market environment.

The model results confirm that increased cooperation in balancing markets is highly beneficial and the degree of cost savings depends highly on the depth of cooperation. The *Imbalance Netting* scenario show only minor cost savings, which can be largely increased by introducing *Joint Activation*. The largest benefits can be gained in the *Full Cooperation* scenario, where not only joint activation but also joint procurement of balancing capacities is conducted. However, this requires the reservation of interconnector capacity for balancing purposes, which could potentially negatively influence the spot market outcome, if too much capacity is reserved. This coordinated procurement and cross-border capacity reservation mostly shifts capacity reservation from Germany towards Austria and Switzerland. These shifts are largely driven by the countries' different power plant portfolios, as run-of-river plants, hydro reservoirs and pumped storage are used to provide balancing capacities.

Chapter 4: Power system impacts of electric vehicles in Germany

A trend in the electricity sector is the increased electrification of applications by switching away from fossil fuels. This is also the case in the transport sector where internal combustion engines powered by mostly fossil fuels can be replaced by electric drive-trains powered by battery-stored power, that can be generated by the multiple generation technologies in the system. As today's power mix in Germany relies on a combination of fossil, nuclear, and renewable electricity generation, the carbon-intensity of EVs is not necessarily advantageous, as especially the additional demand of EVs could lead to a higher utilization of lignite- or hard coal-powered generation. With the rising share of renewables in the system, and the accompanying decrease in specific CO_2 emissions, the incentive towards electric drive-trains is likely to accelerate.

Chapter 4 analyzes the impacts of future scenarios of EVs on the German power system, drawing on different assumptions on the charging mode. In a fully user-driven mode, charging largely occurs during daytime and in the evening, when power demand is already high. User-driven charging thus may have to be restricted because of generation adequacy concerns when no dependence on imports from neighboring regions is assumed. In contrast, cost-driven charging is carried out during night-time and at times of high PV availability. Using a novel model formulation that allows for simulating intermediate charging modes, we show that even a slight relaxation of fully user-driven charging results in much smoother load profiles. Further, cost-driven EV charging strongly increases the utilization of hard coal and lignite plants in 2030, whereas additional power in the user-driven mode is predominantly generated from

Table 1.2.: Overview of Chapters 5–7: Pre-publications and own contribution

Chapter	Pre-publications and own contribution
5. The role of electricity transmission infrastructure in Germany	Chapter 7 in the book "Energiewende – A Mid-Term Perspective on Electricity Sector Reform in Germany" by von Hirschhausen et al. (under review). Single author chapter.
6. Is there still a case for merchant interconnectors?	This chapter is based on IEEE Conference Publication for the 10th International Conference on the European Energy Market (EEM 2013) (Gerbaulet et al., 2013b), and the DIW Berlin Discussion Paper No. 1404 (Gerbaulet and Weber, 2014). A revised version has been submitted to Energy Policy. It was also presented at the 9th Conference on Energy Economics and Technology (ENERDAY 2014) in Dresden, Germany and the 13th European IAEE Conference 2013 in Düsseldorf, Germany. Joint work with Alexander Weber. Clemens Gerbaulet and Alexander Weber jointly developed the model as well as the implementation in GAMS. Casimir Lorenz was also involved in developing previous versions of the model. The writing of the manuscript was executed jointly.
7. European electricity grid infrastructure expansion in a 2050 context	This article first appeared in The Energy Journal, Vol. 37, No. 1, pages 101–124, 2016 DOI: `https://doi.org/10.5547/01956574.37.SI3.jege` - Reproduced by permission of the International Association for Energy Economics (IAEE). Previous versions were published as DIW Berlin Discussion Paper No. 1299 (Egerer et al., 2013a) and presented at the 13th European IAEE Conference 2013 in Düsseldorf, Germany, the 10th International Conference on the European Energy Market (EEM 2013), and the 8th Annual Trans-Atlantic Infraday (TAI 2014) in Washington, USA. Joint work with Jonas Egerer and Casimir Lorenz. Jonas Egerer, Clemens Gerbaulet, and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.

natural gas and hard coal. Specific CO_2 emissions of EVs are substantially higher than those of the overall power system, and highest under cost-driven charging. In additional model runs, we link the introduction of EVs to a respective deployment of additional renewables. Here, electric vehicles become largely CO_2-neutral.

Chapter 5: The role of electricity transmission infrastructure in Germany

The development of the transmission infrastructure has been expected to become a potential bottleneck in the development of the German energiewende and the low-carbon sector transformation in general. Chapter 5 reviews the process of planning

the German high voltage grid before and after 2011, where the transmission planning was completely reorganized by the new German Energy Law of 2011 following the third directive on the internal European Electricity Market (EC, 2009c).

The current methodology employed to do long-run grid expansion planning is based around the concept of the single price zone, leading to a "copper plate" grid with little congestion in the long run. It finds that, although some projects are behind schedule, the overall expansion is continuing steadily, and while there have been significant increases in redispatch measures, the overall system stability has not deteriorated.

This chapter shows that concerns are less severe than stated, and that transmission expansion demand tends to be overestimated due to incentives provided to the TSOs.

One finding discussed in this chapter may offer potential for innovation in transmission expansion planning: The explicit link between transmission planning and climate targets. In 2015, the scenario framework for the network planning exercise introduced climate goals into the planning process for the first time. Thus, it made clear that, like other parts of the energy infrastructure, electricity networks should be planned following the objectives of the energiewende, including the greenhouse gas emission reduction targets. Previously, the energy mix was taken as given in the transmission planning procedure. Now, the German regulator has introduced an explicit CO_2 target into the scenarios as the basis for network planning. By tightening this constraint over time, the German government should be able to facilitate the achievement of CO_2 emission targets for the energy sector, and at the same time, plan the network effectively to achieve the energiewende objectives.

Chapter 6: Is there still a case for merchant interconnectors?

Despite the ongoing appetite of financial investors and project developers for merchant investments into the European electricity network, the EC is reluctant to approve such undertakings, thus implicitly favoring regulated investments. Chapter 6 tries to gain an understanding of the EC's reasoning, by applying a two-level model, to analyze the impact of profit-maximizing merchant transmission investment compared to both welfare-maximizing regulated transmission investment and the absence of enhanced HVDC interconnection between different synchronous areas.

The question is applied to the Baltic Sea region, which has been historically subject to rapid interconnector development, with plans for new interconnectors, as the region would likely benefit from increased interconnection. The model results indicate that merchant investment may well positively contribute to overall welfare. As expected at the outset, "the merchant takes it all," i.e. in many cases merchant profits are close to the overall efficiency gain. This implies that, depending on political objectives, building no interconnector may be superior to building a merchant interconnector if

a regulated solution does not seem to be feasible. This underlines that distributional aspects, beyond mere welfare arguments, should be taken into account when analyzing the impact of merchant transmission investment. Thus, the reasoning of the EC's decisions not to grant exemptions from regulation, or allow "regulatory holidays" for a limited time for new interconnectors can be explained by the chapter's results.

Chapter 7: European electricity grid infrastructure expansion in a 2050 context

In Chapter 7, the focus is shifted away from estimating the effect of investments in a limited set of lines, but to the entire European system. The *Energy Roadmap 2050* by the EC (2011b) develops scenarios for the transformation of the energy sector, with the decarbonization target in mind. The analysis includes a high level estimation of investments in cross-border grid expansion, but does not provide detailed information on investment into the actual HVAC and HVDC grid.

This chapter analyzes the development of the European electricity transmission network for different policy scenarios at the horizon 2050. The research in this chapter has been conducted as part of the infrastructure assessment sub-group of the 28th iteration of the Energy Modeling Forum (EMF). Here, a large scale bottom-up techno-economic electricity sector model is applied, to determine transformation scenarios for the European electricity sector until 2050 in ten-year steps. The model includes every line of the European high-voltage transmission network, as well as a set of potential HVDC-connections, that could function as an overlay grid. This very detailed spatial disaggregation allows for a fine representation of domestic and international electricity flows and transmission expansion. Options for transmission expansion are either an increase in the voltage of a line up to 380 kV, or the installation of an additional circuit. The system-cost-minimizing mixed-integer model calculates investments into the grid infrastructure in time steps of ten years.

The model results indicate that network requirements are lower than generally assumed. The largest share are domestic upgrades, rather than country interconnectors. The largest investment difference between scenarios is realized between the GHG emission reduction targets, as the high-mitigation scenarios require large additional network investments. The timing and location of investments differ, depending on generation scenarios and cost assumptions for interconnectors. Depending on the scenario, the structure of investments shifts from intra-regional to inter-regional transmission demand. The results also indicate that carbon emission reduction targets alone provide insufficient information for long-term network planning.

Table 1.3.: Overview of Chapters 8 and 9: Pre-publications and own contribution

Chapter	Pre-publications and own contribution
8. A dynamic investment and dispatch Model (dynELMOD)	This chapter is based on DIW Berlin Data Documentation No. 88 (Gerbaulet and Lorenz, 2017). The model and data are published under an open source license. Previous versions were presented at 14th IAEE European Energy Conference 2014 in Rome, Italy, the 9th Annual Trans-Atlantic Infraday (TAI 2015) in Washington, USA, the 9th Conference on Energy Economics and Technology (ENERDAY 2014), Dresden, and the 11th International Conference on the European Energy Market (EEM 2014), with a publication as a IEEE Conference Publication (Gerbaulet et al., 2014). Findings and policy implications of model applications are also published in the DIW Economic Bulletin 41/2015 *Future of nuclear power* (Kemfert et al., 2015), and the DIW Economic Bulletin 44/2016 *Nuclear power in Europe* (Lorenz et al., 2016). Joint work with Casimir Lorenz. Clemens Gerbaulet and Casimir Lorenz jointly developed the model as well as the implementation in GAMS. The writing of the manuscript was executed jointly.
9. Scenarios for decarbonizing the European electricity sector	Previous versions were presented at the 10th Annual Trans-Atlantic Infraday (TAI 2016) in Washington, USA, and the 10. Internationale Energiewirtschaftstagung (IEWT 2017) in Vienna, Austria. Joint work with Christian von Hirschhausen, Casimir Lorenz, Claudia Kemfert, and Pao-Yu Oei. Clemens Gerbaulet and Casimir Lorenz conducted the model development and analysis; the writing of the manuscript was executed jointly.

Chapters 8 and 9: A dynamic investment perspective on generation and transmission development in Europe

On the path to decarbonization in the European electricity sector the electricity generation portfolio is undergoing a significant transformation to a largely renewable and GHG-emissions free system. It is likely that the ambitious climate targets can only be reached when a significant share of electricity production comes from renewables such as wind and solar power, as nuclear power and CCTS technologies might not provide safe and/or feasible options of electricity supply. Chapter 8 presents the large-scale open-source electricity sector model dynELMOD, and analyzes future electricity generation portfolio options. Scenarios for the decarbonization of the European electricity sector with regards to boundary conditions such as the planners' foresight or the emission target is conducted in Chapter 9.

dynELMOD is a dynamic investment and dispatch model for Europe with the objective is to minimize total system costs until 2050. To do so, the model can decide endogenously upon investments into conventional and renewable power plants, and

different storage technologies including DSM and the electricity grid. The investments are determined on a county level in 5-years steps with a variable foresight length. The underlying electricity grid and cross-border interaction between countries is approximated using a FBMC approach using a PTDF matrix. One of the main constraints driving investments is an exogenously determined emission path, reaching almost complete decarbonization until 2050. For the investment decisions a reduced time frame is considered, based on a self-developed time frame reduction technique. Dispatch calculations are done in a subsequent step with a full year to be able to check the system for adequacy. The time frame reduction technique and allows to represent the general and seasonal characteristics of an entire year but also to achieve a continuous time series of a day for renewables feed-in and electricity demand.

The model results show that renewable energy sources will provide the majority of the electricity generation in Europe. As production from nuclear energy and fossil fuels is phased out gradually due to high costs and in order to meet the GHG emission targets, the share of renewable generation rises to meet the demand. At the same time with a rising renewables share, especially after 2040, the need for storage capacities increases.

Chapter 9 sketches out several scenarios of the transformation of the European electricity sector in a dynELMOD application and discusses the implication of different assumptions on the foresight of the actors, such as perfect foresight, myopic foresight, and a budgetary approach. The difference in investments into low-carbon technologies with respect to the planners' foresight reveals insights into the potential of stranded assets, that are built under the assumption that the decarbonization is not followed through with. When the emission target (in form of a hard emission constraint in the model) tightens, these previously built capacities can not produce enough electricity to justify the investment and thus should not have been built at the outset. In the budgetary approach, the model is free to distribute emissions between time steps as long as a total emission budget is not exceeded. This gives insights in a lower cost path of decarbonization in the electricity sector.

1.7. Research outlook

The open-source model dynELMOD presented in Chapters 8 and 9 works under the assumption, that all constraints such as the exogenous CO_2 emission target are complied with, and the planner is able to guide the investments into infrastructure with a European cost-minimization target in mind. To reach the targets in reality, full cooperation of all countries, even those that do not directly profit, e.g. by having to build a lot of transmission infrastructure for transit, is required. Also political idiosyncrasies could play an important role in actual sector development and in the

implementation of regional cooperation, ranging from technology preferences over self-sufficiency ambitions to fears of rising electricity prices stemming from increased interconnection.

Furthermore, not all countries are likely or willing to adopt a strategy to carry their share in reducing GHG emissions to reach the 2 °C or even the 1.5 °C target. Therefore, deeper analysis of distributional effects of the energy sector transformation and also externalities of the strongly increased use of renewable electricity sources is required to develop strategies to achieve the targets set. Being able to add some notions of preference or local resistance or limiting the speed of transformation could provide valuable insights into possibilities for real world implementation of large scale infrastructure investments. This could also help answering the question what strategies to apply to achieve the targets with a high probability.

dynELMOD is currently limited to a representation of the electricity sector. While the increase in demand due to increased sector coupling is implemented by anticipation of rising electricity demand even in the light of efficiency measures, a more complete analysis of the interdependencies stemming from increased sector coupling could allow for more complete assessments of the entire sector. As the trend to electrification continues especially in the transportation and heat sectors, the consumer preferences lead not only to switches between fossil fuels, but power is regarded as a fuel. The inclusion of the heat sector into dynELMOD has already been started; and the findings and model implementations from Chapter 4 provide a good starting point for the implementation of electromobility into dynELMOD. As soon as the temporal flexibility of heating and EV charging are implemented, also further system flexibility aspects can be analyzed more thoroughly. The need for storage, or potential power-to-X could potentially be reduced by an increased smartness of the overall system when the heating/cooling, EV charging, or other advanced DSM measures could influence the dispatch substantially.

The balancing reserve markets continue to evolve and adapt. They only contribute to a small portion of overall electricity system cost, but have a high relevance in the broader context to mitigate short term fluctuations in a system with an increasing number of participants. In the current setting solar PV is not included in the analysis, but as the development further progresses, new solar PV capacities could also participate. Another topic of interest could be a joint procurement of redispatchable capacities with balancing. In case of temporal grid congestion, dispatching capacities that are reserved for balancing capacities should be possible from a technical standpoint and lead to a decrease in overall system cost. Furthermore, following the notion of smart grids, one could imagine the implementation of demand side management, also used for balancing services as some form of supervisory control and data acquisition (SCADA) system needs to be implemented into DSM applications

to be able to react to demand shifting requirements. With such a high number of potential market participants, the prices for balancing capacity or balancing energy are likely to decrease. Furthermore, auto-adaptive FCR could also be built into many industrial appliances, as the cost of such kind of automation decreases.

Part I

Operational and market aspects

Chapter 2

Wind providing balancing reserves – Model development and application to the German electricity system of 2025

This chapter is based on DIW Berlin Discussion Paper No. 1655 (Lorenz and Gerbaulet, 2017) and submitted to Applied Energy.

2.1. Introduction

The degree of reliability of every electricity system depends on the functioning of all components and market segments. One of these markets is the balancing market and effective operation of balancing reserves to control short-term deviations of demand and supply is paramount. In this chapter we analyze possible price and dispatch developments in the German balancing market until 2025. The application to Germany proves to be an interesting study topic, as the current market structure might change significantly in the future. The range of changes is manifold and includes adjustments to auction design, increased market harmonization with neighboring countries, transformation of the power plant portfolio and entrance of new market participants. We want to analyze the effects of the latter two.

In the context of the low carbon transformation of the electricity system, the share of renewables is expected to increase. The rising share of renewable energy sources (RES) could lead to a change in balancing reserve demand (see Section 2.3) but could also enable participation of renewables in the provision of balancing reserves, where (among other actors) fluctuating renewables will be able to offer a percentage of their output on the market.

The reasons for deviations from the alternating current (AC) system's nominal frequency of 50 Hz can be numerous: i) load fluctuates constantly and cannot be forecast perfectly, ii) schedule leaps occur between each auctioned (quarter) hour, iii) power plant or grid outages take place unexpectedly, and iv) the in-feed of RES deviates from its forecast. All these deviations alter the system's frequency, balancing reserves restore and stabilize the frequency by activating upward or downward reserves. The balancing market in Germany is organized in three products, distinguished by their response time and length of activation. In Germany these products are primary balancing power (PRL, Primärregelleistung), secondary balancing power (SRL, Sekundärregelleistung), and tertiary balancing power (TRL, Tertiärregelleistung), corresponding to the nomenclature primary control (PC), secondary control (SC), and tertiary control (TC) of this chapter.[1]

[1] These products are auctioned by the four German transmission system operators (TSOs) on a joint platform, where some pre-qualified units from outside of Germany are able to participate. The German TSOs are also part of the International Grid Control Cooperation (IGCC), which fosters cross-border balancing exchanges. Together with seven neighboring TSOs, imbalance netting of SC capacities is applied to reduce total activation volumes. Throughout the literature different terms like balancing reserves, balancing capacity, control power, control energy are used. We will use the terms balancing reserves, balancing power and balancing energy that are used by ENTSO-E (2013a). The differentiation of the balancing power products used in this chapter corresponds to the German variant. Thus, short-time load frequency control products such as frequency containment reserve (FCR) are PC, while automatic frequency restoration reserve (aFRR) is denoted as SC and manual frequency restoration reserve (mFRR) is denoted as TC in this chapter. Furthermore, replacement reserve (RR) are used to restore the required level

The current state and development of the German balancing markets is discussed in general in Hirth and Ziegenhagen (2015), Koliou et al. (2014), Mauritzen (2015), and Müsgens et al. (2011). The majority of the literature focuses research questions ranging from technical balancing frameworks and the integration of renewables, the market design, or pricing policies. Methods of analysis are manifold, starting with numerical fundamental models (Chao and Wilson, 2002; Müsgens et al., 2014; Ortner and Graf, 2013; Swider, 2007). These models are often mixed integer linear programs (MILPs) with a detailed representation of power plant characteristics in the dispatch. Stochastic approaches are applied by Just (2011) and Lindsjørn (2012). The evaluation of statistical (panel-)data such as realized market outcomes and company behavior is conducted by Growitsch et al. (2010), Haucap et al. (2014), and Heim and Goetz (2013).

The auction design of balancing capacity reservation is often discussed: Abbasy et al. (2010), Bucksteeg et al. (2014), Knaut et al. (2017), Müsgens et al. (2012, 2014), Niesen and Weber (2014), and Swider (2007) discuss lead times in the balancing market and conclude that shorter lead times and increased flexibility of auctions in the balancing market also positively affect the efficiency of the spot market. Böttger and Bruckner (2015), Just and Weber (2008), and Just (2011) show that shorter contract duration lead to efficiency increases and less capacity effectively withheld from the spot market.

Furthermore, the effect of allowing new market participants other than conventional or renewable power plants such as renewables, battery storage, electrical boilers or managed refrigerated warehouses into the market is discussed. As discussed in Hirth and Ziegenhagen (2015) and Sorknæs et al. (2013), fluctuating renewables will most likely supply negative balancing in the next years. However, with increased hours of excess electricity production, it starts to makes sense for RES also to provide positive reserves. During these times, withholding generation from RES for balancing reserves leads to no system cost, as they would be curtailed in any case. The model used in Böttger and Bruckner (2015) is also used in Böttger et al. (2015) to analyze the participation of 1,000 MW of electric boilers on negative SC and show cost savings of about 52-158 million € in Germany in 2025. The effect of participation of wind and solar photovoltaic (PV) on the German balancing market of 2035 is analyzed by Spieker et al. (2016) using a detailed fundamental unit-commitment model. Similar to the results obtained in this chapter, the authors show that with participation of renewables, the total balancing reservation cost are decreased, but remain above 2014 values.

of other reserves (FCR, aFRR, and mFRR) to be prepared for a further system imbalance. No comparable balancing product exists in Germany.

Increased cooperation between neighboring balancing markets regarding reservation and activation of SC and TC reserves between Austria, Germany and Switzerland is carried out in Chapter 3 with the result, that regional cooperation can significantly reduce total reserve provision costs. Similarly, Farahmand and Doorman (2012), Gebrekiros et al. (2013, 2015a,b), and Jaehnert and Doorman (2010) conclude that joint reserve provision in northern Europe is beneficial.

Possibly grouping bids into portfolios also affects the market outcome. Niesen and Weber (2014) formulate an analytical equilibrium model of the balancing market and show that capacity prices are lower with shorter contract durations using a detailed unit commitment model applied to the European electricity market of 2012. If large power plant portfolios are introduced into the market, this effect is reduced. These results are confirmed by Lorenz et al. (2014), who apply a unit-commitment model of the German balancing market that allows for portfolio bidding by large generation companies.

Several of the changes to the current market setup suggested in the literature have been adopted by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Commission (EC). In the current draft of the EC's regulation of establishing a guideline on electricity balancing (EC, 2017), measures such as the harmonization of the balancing products and changes to the gate closure times and pricing structures are addressed, which could further improve the efficiency of the market and enable more flexibility in providing balancing services by wind turbines and other market participants.

This chapter contributes to the existing literature by introducing the fundamental unit commitment model ELMOD-MIP, which features a novel approach of modeling balancing reserve provision by considering possible activation costs during the reservation phase. The anticipation of reserve activation probabilities, should lead to a more realistic balancing reserve dispatch. We use this model to give an outlook on the developments of the German balancing market until 2025 and analyze the influence of wind turbines participating in the provisioning of balancing reserves. The chapter is structured as follows: Section 2.2 describes the characteristics and motivation of ELMOD-MIP, as well as the applied novel approach of our methodology and fundamental price formations in the balancing market. The mathematical formulation of the model is presented in Section 2.2.1. In Section 2.3 the data and scenarios applied to ELMOD-MIP are described. The results are analyzed in Section 2.4 and followed by a conclusion in Section 2.5.

2.2. Methodology

In order to be able to analyze possible changes in the balancing reserve markets, the basis is an accurate representation of the power plant dispatch in the respective market area, as the balancing reserve market is a comparatively small part of the entire electricity sector. The goal is to find an approximation of the prices, quantities and cost that the balancing market could have under the assumption of a perfectly competitive market setup without any inefficiencies and strategic behavior. We focus on secondary and tertiary control reserves and neglect primary control reserves due to comparable small market volumes and complex technical prerequisites for its provision.

In fundamental optimization models, the procurement of balancing reserves is often represented using one or more market clearing equations, that represent the balancing reservation demand and is fulfilled by the market participants by reserving a part of their upward or downward generation potential. This influences the dispatch decision, as the flexibility to operate on the "main" market is restricted by the balancing reservation. Further, the model's selection of what type of generation capacity or power plant is used to provide balancing services is largely influenced by the models' level of detail. This approach can be applied in linear models (Jaehnert and Doorman, 2010; Zerrahn and Schill, 2015a) on a technological or block-sharp level, as well as unit commitment models. These models implement more complex power plant dispatch restrictions such as start-up cost, minimum load, or minimum offline or online durations (van den Bergh et al., 2016; Böttger et al., 2015; Brouwer et al., 2014; Farahmand et al., 2012). The impact of power plants' part-load behavior further influences the model outcome, as especially to be able to provide positive balancing reserves, some upward potential needs to be kept available, leading to a dispatch below the optimum efficiency point. In Bucksteeg et al. (2014) and Knaut et al. (2017) this characteristic is also reflected in the balancing reserves procurement. To further improve the model's selection of capacities for balancing reserves during the balancing reservation phase Gebrekiros et al. (2015b) and Müsgens et al. (2012) include an approximation of opportunity cost between the balancing and spot markets commitment.

Most approaches presented do not anticipate the activation of balancing reserves during the reservation phase, or use static approaches to weigh the decision what capacities should provide balancing services. The approach used this chapter contributes to the literature by presenting an endogenous anticipation of the balancing reserves' activation probability. To represent the market participant's assumptions over the different stages of the balancing market (capacity reservation and energy activation) ELMOD-MIP has the possibility to anticipate the probability of balancing

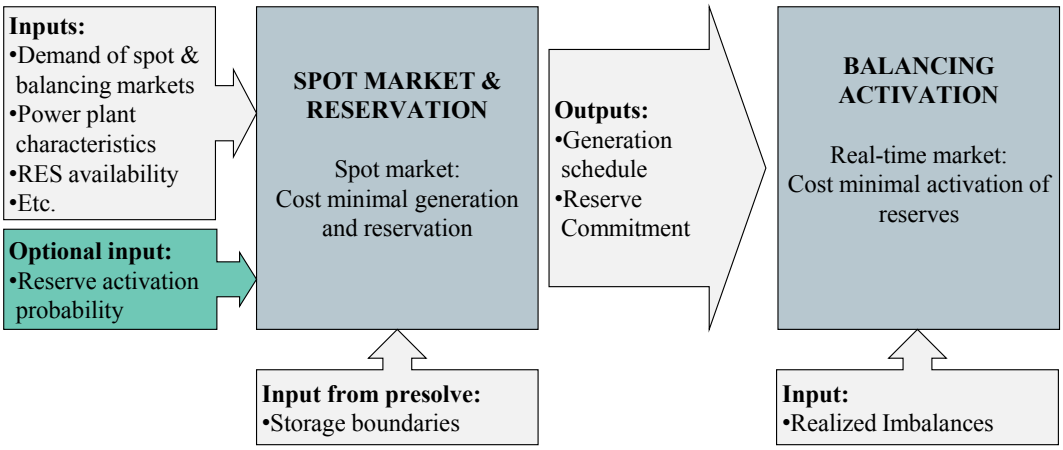


Figure 2.1.: ELMOD-MIP Model Steps

reserve activations during the reservation phase. This anticipation of the activation probability has several advantages: It resembles the behavior that is expected from real market participants, that are likely to include the revenue from the activations in their market participation. In ELMOD-MIP, this leads a more realistic and slightly higher balancing reserve cost estimation than a negligence of the activation probabilities.

ELMOD-MIP is a bottom-up electricity sector model, formulated as a MILP which allows us to include unit-commitment constraints as minimum load, part-load efficiency, time-dependent start-up and shutdown restrictions, complex combined heat and power (CHP) constraints and minimum bid sizes for balancing capacity reservation. These detailed representations of the power plants' flexibility are crucial to accurately represent the power plant dispatch as well as capacity reservation when modeling balancing markets. If these constraints were not part of the model, the power plants' flexibility would be significantly overestimated and distort the balancing market outcome.

2.2.1. The model ELMOD-MIP

We formulate ELMOD-MIP as a multi-step approach (Figure 2.1), where for all steps the same model is used, but some equations are deactivated and some variables and parameters are fixed or set to zero based on each step's goal.

In the first step, the spot and balancing reserve markets are optimized simultaneously, minimizing total system cost. Thus, the balancing capacity reservation as well as the power plant dispatch in the spot market are determined. The actual balancing reserve activations are not part of the optimization, as they are approximated using

the anticipated reserve activation probability, or neglected depending on the scenario (see Section 2.3).

In the second step, the activation of balancing reserve is optimized. Necessary activated balancing reserve is determined based on historical time series. Here, the variables determining the reservation of balancing capacity are fixed in the model. Only power plants with reserved capacity can be dispatched for balancing reserve activations by the model.

To generate storage levels and associated limitations for the starting and end period of each individual week, we solve a limited version of the model ("presolve") for the entire model year prior to the actual calculations using the same input data. The limited version is a linear reformulation with technology sharp aggregation for non-hydro generation and linear balancing requirements.

In this chapter we focus on the cost induced by the balancing reserves' influence on the electricity system as generation technologies reserve capacity to provide them. Hence, the cost for activating these reserves is not fully analyzed in this chapter. Still, balancing reserve activation is fully implemented in the model and the calculations. This is necessary as the activation results in additional technical constraints for the reservation phase. Furthermore, this allows us to study possible impacts on activation cost in subsequent analyses. The cost for balancing activation will therefore only be evaluated briefly.

2.2.2. Determining the cost of balancing reserves

Determining cost and prices for balancing reserve provision in fundamental electricity system models can be a challenge. In contrast to the spot market, balancing reserve cost comprise of different components. Furthermore, the total balancing reserve cost can not be quantified directly, as it is influenced by the spot market situation.

Balancing cost components

In ELMOD-MIP, three factors can induce costs when reserving balancing capacity: Opportunity costs, part-load costs when reserving positive balancing capacity, and the cost of anticipated balancing reserve activation.

First, opportunity costs occur in the spot market due to balancing restrictions on the available generation capacity. Capacity is either reserved in a power plant in case of positive capacity reservation, or a must-run condition is introduced in case of negative capacity reservation. Depending on the difference between current market price and the marginal cost of the power plant opportunity cost are described in (2.1) and (2.2).

$$cost_p^{resv,pos} = \begin{cases} (p^{spot} - mc_p) \cdot G_{p,t}^{resv,pos} & \text{if } p^{spot} \geq mc_p \\ (mc_p - p^{spot}) \cdot g_p^{min} \cdot g_p^{max} & \text{if } p^{spot} \leq mc_p \end{cases} \tag{2.1}$$

$$cost_p^{resv,neg} = \begin{cases} 0 & \text{if } p^{spot} \geq mc_p \\ (mc_p - p^{spot}) \cdot g_p^{min} \cdot g_p^{max} + G_{p,t}^{resv,neg} & \text{if } p^{spot} \leq mc_p \end{cases} \tag{2.2}$$

The opportunity cost for positive reservation are zero if the marginal cost of the power plant equal the current market price. Hence, the price setting power plant can theoretically provide reserves without opportunity cost. Power plants without minimum load constraints, such as pumped hydro or run-of-river power plants (RoR) are able to provide positive reserves at no cost, as long as their water value is above the spot market price. If the water value is lower than the spot market price, opportunity costs occur. Inflexible CHP plants without a heat storage (or other means to provide heat output) also have no opportunity cost for capacity reservation, at times when their marginal costs are above the spot market price but they have to produce heat and therefore need to run at least at minimum load. In this situation they do not face any losses from not offering their spare capacity at the spot market and therefore can provide reserves at no opportunity cost.

Opportunity cost are zero for negative reserves, if the power plants' marginal cost are below the market price and the power plant is producing for the spot market. Hence, as long as a power plants is "in the money," it can provide negative reserves at zero cost. A detailed explanation and more examples can be found in Müsgens et al. (2014) and Brandstätt (2014).

Second, in the case of positive reserve provision, power plants have to produce below their rated capacity and thus are not able to operate at their optimal output point. This results in higher relative fuel cost for electricity production as the power plant's efficiency is reduced. These part-load cost are the biggest cost component when power plants marginal cost are close or equal to the spot price.

The third cost component is the anticipated balancing reserve activation. As the activation probability distribution can be anticipated in ELMOD-MIP (see Section 2.2.3 below), the activation probability of balancing reserves takes into account the cost for additional fuel or startup costs that occur when activated. This also includes anticipated part-load situations when deviations from the optimal power plant dispatch are anticipated.

Balancing cost calculation

In this chapter the cost of balancing reservation is calculated as the difference in system cost, with and without balancing reserve restrictions. Van den Bergh et al. (2016), Gebrekiros et al. (2015b), and Knaut et al. (2017) use a two-step approach that is also used in this chapter. In a first calculation, the amount of balancing capacity reserved is set to zero, and all power plant capacities can operate fully on the spot market. This is compared to the actual calculations with balancing reservation. The increase in cost contains all alterations occurring in the spot market, such as a selection of more costly power plants in the dispatch, as well as part-load costs of power plants that provide positive balancing reserves.

Brandstätt (2014) and Müsgens et al. (2012) estimate the opportunity cost of providing balancing reserves for each power plant in a first step. Based on these cost, they determine which power plants are the cheapest to provide reserves. The product of these cost with the actually reserved capacity gives the total cost of balancing reservation. This approach allows for a plant-sharp estimation of balancing reservation cost, but has the disadvantage of neglecting some aspects of interaction between the spot and balancing markets. Especially the effect of part-load efficiency decrease of the power plants induced by the reservation is neglected, which is a main cost-driver of balancing reserve provision (see above). Thus not all system cost components that arise from balancing reservation are reflected.

2.2.3. Anticipating balancing reserve activations

To be able to incorporate the uncertainty of how much balancing power is actually activated, we separate the balancing reserves into multiple products with different sizes and activation probabilities. This methodology approximates the actual activation distribution, where a small amount of balancing reserves is almost always activated, but the maximum reserved capacity is activated only in a few hours per year. The model uses this information to determine which power plants are likely to be used for the activation of balancing reserves by taking into account the activation cost multiplied by the activation probability. This becomes part of the optimization. Thus, power plants are not just committed to provide balancing capacity, but are committed to a small block of balancing capacity with a certain activation probability. Assigning multiple blocks and splitting each block's capacity to multiple power plants is possible. The effect of this improvement is analyzed in the *2013 Anticipation* scenario (see Section 2.3).

Historical frequencies for SC are shown in Figure 2.2. We derive the distribution of these blocks using historical time series data that are part of the model input described in section 2.3. The sum of each block's size in megawatt (MW) multiplied

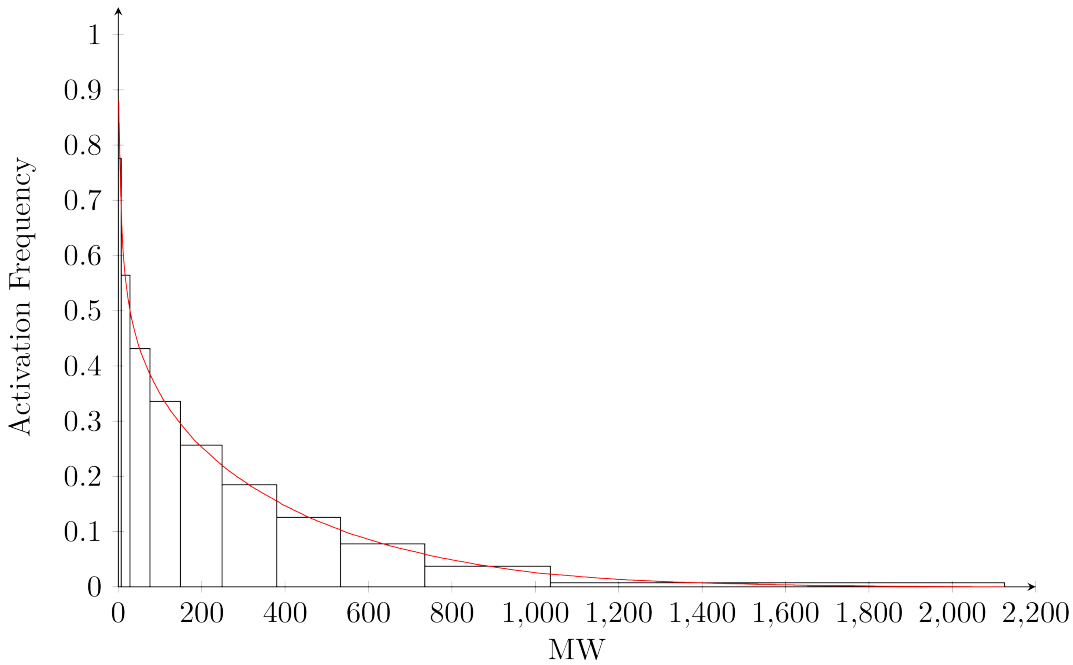


Figure 2.2.: Activation frequency for positive SC in Germany 2013 and calculated blocks.

by the frequency equals the average activation values in MW. This ensures that the model's anticipation of the average balancing reserve activations is correct.

In the current market design, balancing capacity is reserved regularly for time periods between four hours and one week, depending on the product and region. This reservation is allocated to the bidding firm's power plant portfolio and not to individual plants. Therefore, the firms can optimize their power plant portfolio at the time of delivery of the balancing energy, hence at least hourly. In ELMOD-MIP we approximate this setting by allowing for balancing capacity reservation for each power plant and hour separately. This results in a situation similar to various big firms participating in a cost minimizing behavior on the balancing market.

We do not apply price markups for balancing capacity because they might distort the model results significantly in case of changing market situations (induced by increased cooperation or a changed future power plant portfolio), as the markups are usually not endogenous to the model and based on historical data. This approach gives us the possibility to determine a lower bound of the anticipated balancing cost for the future electricity system.

2.2.4. Computational complexity

The problem is solved in 52 weekly blocks with two days overlap[2] to cover a whole year. This allows us to parallelize the calculations and reduce the computation time for an entire year significantly. It is solved with the help of a unix cluster. Up to 50 nodes were used in parallel, each equipped with at least 16 GB of RAM and AMD or Intel processors of at least 2.6 GHz. For the scenarios without anticipation, each calculation period needs up to 20 hours. Thanks to parallelization each scenario can be calculated in less than two days. However, the scenarios with anticipation need up to one week of wall-clock time as each calculation period can take up to 100 hours.

2.2.5. Mathematical formulation

The objective of ELMOD-MIP is to minimize total system costs, while clearing the spot market as well as the balancing market for the two balancing power products SC and TC. The model is solved using the General Algebraic Modeling System (GAMS) with the commercial solver CPLEX.

The mathematical formulation can be found in equations (2.3) to (2.53). The overall objective is to minimize the sum of generation, start-up, shut-down, and balancing cost (2.3 – 2.10). For the scenarios where no anticipation of activations is included, the parameter $frq_{bl,b}$ is set to zero and equations are simplified.

$$\begin{aligned} \min Cost^{total} = \; & Cost^{gen} + Cost^{start} + Cost^{down} + Cost^{ramp} \\ & + Cost^{partload} + Cost^{resv} + Cost^{call} \end{aligned} \tag{2.3}$$

s.t.

$$Cost^{gen} = \sum_{c,t} mc_c \cdot G_{c,t} \tag{2.4}$$

$$Cost^{start} = \sum_{c,t} UP_{c,t} \cdot c_c^{start} + \sum_{u,t} Frq_{u,t}^{max} \cdot c_u^{start} \tag{2.5}$$

$$Cost^{down} = \sum_{c,t} DN_{c,t} \cdot c_c^{down} + \sum_{u,t} Frq_{u,t}^{max} \cdot c_u^{down} \tag{2.6}$$

$$Cost^{ramp} = \sum_{p,t} G_{p,t}^{rampup} \cdot c_c^{rampup} + G_{p,t}^{rampdown} \cdot c_c^{rampdown} \tag{2.7}$$

[2]See Barrows et al. (2014) for an analysis of time series partitioning and overlap times. The authors suggest the setting used in this chapter to achieve adequate solutions while achieving fast solution times.

$$Cost^{partload} = \sum_{c,t} ON_{c,t} \cdot c_c^{partload} - \frac{c_c^{partload}}{g_c^{max} \cdot ava_{c,t} - g_c^{min} \cdot g_c^{max}} \cdot \Bigg(G_{c,t} - g_c^{min} \cdot g_c^{max} + \sum_b \Bigg(G_{b,c,t}^{call,pos} - G_{b,c,t}^{call,neg} + \sum_{bl} \Big((G_{u \in c,t,bl,b}^{resv,pos} - G_{u \in c,t,bl,b}^{resv,neg}) \cdot frq_{bl,b} \Big) \Bigg) \Bigg) \tag{2.8}$$

$$Cost^{resv} = \sum_{b,bl,c,t} mc_c \cdot \left(G_{c,t,bl,b}^{resv,pos} - G_{c,t,bl,b}^{resv,neg} \right) \cdot frq_{bl,b} \tag{2.9}$$

$$Cost^{call} = \sum_{b,c,t} mc_c \cdot \left(G_{b,c,t}^{call,pos} - G_{b,c,t}^{call,neg} \right) \tag{2.10}$$

The total system costs (2.3) include variable costs of generation (2.4), start-up (2.5) and shut-down (2.6) costs, ramping cost (2.7), part-load cost (2.8) and the costs for providing balancing power (2.9) and (2.10). The variable cost of generation is defined as the generation $G_{c,t}$ of all conventional power plants c and time steps t multiplied by the plants' marginal production cost mc_c. Start-up cost c_c^{start} occur when a plant assumes production and was in a shut-down state in the previous time step. Then, the binary variable $UP_{c,t}$ has the value 1.

During the reservation phase the expected start up probability of fast-starting power plants u, which is a subset of all conventional power plants c, is also taken into account. Shut-down cost occur analogously. For fast-starting power plants that do not participate in the spot market at the time of activation, we assume that these plants provide balancing power for a short time period and shut down afterward. Therefore not only the startup cost c_u^{start} but also the shut-down cost c_u^{down} are taken into account as well during the reservation phase.

The reservation of positive or negative balancing capacity $G_{c,t,bl,b}^{resv,pos}$ and $G_{c,t,bl,b}^{resv,neg}$ for the balancing power products b and blocks bl incurs opportunity cost mc_c multiplied with the block's specific activation frequency $frq_{bl,b}$ in the model, as the capacity reservation reduces the available capacity in the spot markets. The balancing reserve activations $G_{b,c,t}^{call,pos}$ and $G_{b,c,t}^{call,neg}$ are accounted for by the power plants' marginal cost mc_c. The part-load cost represent the non-linear link between fuel cost per produced MWh depending on current output level. At minimum generation level, part load cost in the magnitude of $c_c^{partload}$ would occur. When a power plant is operating above minimum generation level, these costs are reduced depending on current output level $G_{c,t}$ as expressed in the fraction.[3]

[3]The combination of equations (2.4) and (2.8) replicates the part-load decrease of a power plant's efficiency η using the formula $\eta(G) = \frac{G}{aG+b}$ where $G \in [g^{min}, g^{max}]$. a and b are power plant specific parameters, g^{min} and g^{max} are minimum and full power plant output.

Market clearing

The spot market is cleared by leveling load $q_{r,t}^{spot}$, dispatchable generation $G_{c,t}$, storage activity $G_{s,t}^{up}$, $G_{s,t}^{down}$, non-dispatchable renewable and conventional feed-in $g_{r,t}^{res}$, $g_{r,t}^{conv}$, and exogenous exchange flows g^{cb} for all time steps t and regions r, as stated in (2.11). Markets for positive and negative balancing capacity are cleared separately for each product b and block bl, by leveling demand $q_{b,bl,r,t}^{resv,pos}$, $q_{b,bl,r,t}^{resv,neg}$ and reserves $G_{p,t,bl,b}^{resv,pos}$, $G_{p,t,bl,b}^{resv,neg}$. This is shown in (2.12) and (2.13) for the reservation and in (2.14) and (2.15) for the activation of balancing reserve.

$$\begin{aligned} 0 = q_{r,t}^{spot} - \sum_{c \in r} G_{c,t} + \sum_{s} \left(G_{s,t}^{up} - G_{s,t}^{down} \right) \\ - g_{r,t}^{res} - g_{r,t}^{conv} - g_{r,t}^{cb} \end{aligned} \qquad \forall r, t \qquad (2.11)$$

$$q_{b,bl,r,t}^{resv,pos} = \sum_{p \in r} G_{p,t,bl,b}^{resv,pos} \qquad \forall t, r, bl, b \qquad (2.12)$$

$$q_{b,bl,r,t}^{resv,neg} = \sum_{p \in r} G_{p,t,bl,b}^{resv,neg} \qquad \forall t, r, bl, b \qquad (2.13)$$

$$q_{b,r,t}^{call,pos} = \sum_{p \in r} G_{b,p,t}^{call,pos} \qquad \forall b, r, t \qquad (2.14)$$

$$q_{b,r,t}^{call,neg} = \sum_{p \in r} G_{b,p,t}^{call,neg} \qquad \forall b, r, t \qquad (2.15)$$

Generation restrictions

$$G_{c,t} \leq g_c^{max} \cdot ava_{c,t} - \sum_{bl,b} G_{c,t,bl,b}^{resv,pos} \qquad \forall c, t \qquad (2.16)$$

$$G_{c,t} \geq g_c^{min} \cdot g_c^{max} \cdot ON_{c,t} + \sum_{bl,b} G_{c,t,bl,b}^{resv,neg} \qquad \forall c, t \qquad (2.17)$$

$$G_{o,t} \leq ON_{o,t} \cdot g_o^{max} \cdot ava_{o,t} - \sum_{bl,b} G_{o,t,bl,b}^{resv,pos} \qquad \forall o, t \qquad (2.18)$$

$$G_{u,t} \leq ON_{u,t} \cdot g_u^{max} \cdot ava_{u,t} - \sum_{bl} G_{u,t,bl,sc}^{resv,pos} \qquad \forall u, t \qquad (2.19)$$

$$DN_{c,t} + ON_{c,t} = UP_{c,t} + ON_{c,t-1} \qquad \forall c, t \qquad (2.20)$$

$$UP_{c,t} + DN_{c,t} \leq 1 \qquad \forall c, t \qquad (2.21)$$

$$1 - UP_{c,t-t_c^{minup}} \geq \sum_{tt=t-t_c^{minup}}^{t} DN_{c,tt} \qquad \forall c, t \qquad (2.22)$$

$$1 - DN_{c,t-t_c^{mindn}} \geq \sum_{tt=t-t_c^{mindn}}^{t} UP_{c,tt} \qquad \forall c, t \qquad (2.23)$$

$$G_{c,t} \geq \sum_{b,bl} G^{resv,neg}_{b,bl,c,t} \qquad \forall c,t \qquad (2.24)$$

$$G^{resv,pos}_{tc,bl,u,t} \leq (SB_{b,bl,u,t} + ON_{u,t}) \cdot g^{max}_{u} \qquad \forall tc,bl,u,t \qquad (2.25)$$

$$G^{resv,pos}_{tc,bl,u,t} \geq SB_{b,bl,u,t} \cdot g^{max}_{u} \cdot g^{min}_{u} \qquad \forall tc,bl,u,t \qquad (2.26)$$

$$Frq^{max}_{u,t} \geq SB_{b,bl,u,t} \cdot frq_{b,bl} \qquad \forall b,bl,u,t \qquad (2.27)$$

$$1 \geq SB_{b,bl,u,t} + ON_{u,t} \qquad \forall b,bl,u,t \qquad (2.28)$$

A power plant's generation $G_{c,t}$ and balancing reservation $G^{resv,pos}_{c,t,bl,b}$, $G^{resv,neg}_{c,t,bl,b}$ are constrained by its minimal and maximal generation capacity (2.16), (2.17). Slow starting power plants o have to be online to provide balancing power (2.18) while fast starting power plants u must only be online when providing energy for the spot market (2.19) and can be on stand-by to provide reserves (2.25). In case of activation of reserve energy we assume that these power plants can reach the desired output levels within time from a shutdown state. Equation (2.20) tracks the plant's status for start-up and shut-down costs and enforces the plant to start up when providing balancing power. Power plants are further restricted by minimum online and offline times. If a plant was started up it cannot be shut down within the interval $t^{minup}_{c,t}$ and vice versa for start ups after a shut down as shown in (2.22) and (2.23). The amount of negative reserved balancing power must always be smaller that the spot market generation of the power plant (2.24). This enforces power plants to be online and to participate in the spot market in order to provide negative balancing power. Slow starting power plants o must be online to provide positive balancing power as well (2.18), whereas fast starting power plants u can be in standby mode (2.25). Fast starting power plants must bid at least their g^{min} when they are bidding out of a standby status (2.26). Fast starting plants that are not generating but provide balancing power will incur their start-up and shut-down costs according to their expected activation frequency (2.27). Equation (2.28) ensures that plants can only either be online or in standby mode.

Combined heat and power

Power plants that additionally deliver heat to industrial or residential customers are further restricted in their operation by the equations (2.29) to (2.33). We separate the CHP plants into plants with a heat storage *chps* and plants without the possibility to store heat *chpn*. The heat storage level $Chp^{storagelevel}_{chps,t}$ is defined in equation (2.30) as the level from the previous hour times an heat loss factor plus heat generation by the power plant $Chp^{output}_{chps,t}$ and minus the heat that is consumed by industry or households. The heat generation is limited in (2.29) not to be higher than the current generation level. The heat level and output are measured in MWh electrical energy

but not thermal energy, as the heat demand is also specified as a minimum electricity generation.

$$Chp^{output}_{chps,t} \leq G_{chps,t} \qquad \forall chps, t \qquad (2.29)$$

$$\begin{aligned} Chp^{storagelevel}_{chps,t} &= Chp^{storagelevel}_{chps,t-1} \cdot eta^{chp} \\ &+ Chp^{output}_{chps,t} - g^{min,chps}_{chps,t} \cdot g^{max}_{chps,t} \end{aligned} \qquad \forall chps, t \qquad (2.30)$$

$$Chp^{storagelevel}_{chps,t} \leq chp^{storagemax}_{chp} \qquad \forall chps, t \qquad (2.31)$$

$$G_{chpn,t} + \sum_{bl,b} G^{resv,pos}_{chpn,t,bl,b} \leq g^{max,chp}_{chp,t} \cdot g^{max}_{chpn,t} \qquad \forall chpn, t \qquad (2.32)$$

$$G_{chpn,t} - \sum_{bl,b} G^{resv,neg}_{chpn,t,bl,b} \geq g^{min,chp}_{chp,t} \cdot g^{max}_{chpn,t} \qquad \forall chpn, t \qquad (2.33)$$

Power plants without heat storage are constraint by equations (2.32) and (2.33). In contrast they have to produce the heat at the specific hour it is needed. The parameters $g^{max,chp}_{chp,t}$ and $g^{min,chp}_{chp,t}$ are determined based on power plant characteristics and an exemplary heat demand curves dependent on outside temperature and hour of the day.

Ramping

$$G^{rampup}_{c,t} \leq r^{up}_{c} \cdot g^{max}_{c} + \sum_{bl,b} G^{resv,neg}_{c,t-1,bl,b} - \sum_{bl,b} G^{resv,pos}_{c,t,bl,b} \qquad \forall c, t \qquad (2.34)$$

$$G^{rampdown}_{c,t} \leq r^{down}_{c} \cdot g^{max}_{c} + \sum_{bl,b} G^{resv,neg}_{c,t,bl,b} - \sum_{bl,b} G^{resv,pos}_{c,t-1,bl,b} \qquad \forall c, t \qquad (2.35)$$

$$\begin{aligned} G_{c,t} - G_{c,t-1} &+ \sum_{bl,b} (G^{resv,pos}_{c,t,bl,b} - G^{resv,pos}_{c,t-1,bl,b}) \cdot frq_{bl,b} \\ &- \sum_{bl,b} (G^{resv,neg}_{c,t,bl,b} - G^{resv,neg}_{c,t-1,bl,b}) \cdot frq_{bl,b} \\ &+ \sum_{b} (G^{call,pos}_{b,c,t} - G^{call,pos}_{b,c,t-1}) - (G^{call,neg}_{b,c,t} - G^{call,neg}_{b,c,t-1}) \\ &= G^{rampup}_{c,t} - G^{rampdown}_{c,t} \end{aligned} \qquad \forall c, t \qquad (2.36)$$

The power plants' ramping restrictions are included in (2.34) and (2.35). These equations limit the change of a power plant's production levels between time steps. For ramping, only the limiting balancing reservations are included, as otherwise the model would be able to weaken the ramping restrictions by reserving balancing capacity in the reverse direction.

Reserve restrictions

$$\sum_{bl} G^{resv,pos}_{b,bl,p,t} \geq resv^{min}_{b} \cdot BAL^{pos}_{b,p,t} \qquad \forall b,p,t \qquad (2.37)$$

$$\sum_{bl} G^{resv,neg}_{b,bl,p,t} \geq resv^{min}_{b} \cdot BAL^{neg}_{b,p,t} \qquad \forall b,p,t \qquad (2.38)$$

$$\sum_{bl} G^{resv,pos}_{b,bl,s,t} \leq v^{max}_{s} \cdot BAL^{pos}_{b,s,t} \qquad \forall b,c,t \qquad (2.39)$$

$$\sum_{bl} G^{resv,neg}_{b,bl,s,t} \leq w^{max}_{s} \cdot BAL^{neg}_{b,s,t} \qquad \forall b,c,t \qquad (2.40)$$

$$\sum_{bl} G^{resv,pos}_{sc,bl,c,t} \leq g^{max}_{c} \cdot r^{up}_{c} \cdot BAL^{pos}_{sc,c,t} \cdot 5 \qquad \forall c,t \qquad (2.41)$$

$$\sum_{bl} G^{resv,pos}_{tc,bl,c,t} \leq g^{max}_{c} \cdot r^{up}_{c} \cdot BAL^{pos}_{tc,c,t} \cdot 15 - \sum_{b,bl} G^{resv,pos}_{sc,bl,c,t} \qquad \forall c,t \qquad (2.42)$$

$$\sum_{bl} G^{resv,neg}_{sc,bl,c,t} \leq g^{max}_{c} \cdot r^{down}_{c} \cdot BAL^{neg}_{sc,c,t} \cdot 5 \qquad \forall c,t \qquad (2.43)$$

$$\sum_{bl} G^{resv,neg}_{tc,bl,c,t} \leq g^{max}_{c} \cdot r^{down}_{c} \cdot BAL^{neg}_{tc,c,t} \cdot 15 - \sum_{b,bl} G^{resv,neg}_{sc,bl,c,t} \qquad \forall c,t \qquad (2.44)$$

Equations (2.37) to (2.44) describe the restrictions that determine how much of a plant's capacity can be reserved for balancing. The combination of (2.37) and (2.38) enforces power plants or storages to bid at least the minimum bid specified by $resv^{min}_{b}$ when bidding into the balancing market. Storage plants can (besides other restrictions) only reserve as much capacity as limited by their pumping and generating abilities as seen in (2.39) to (2.40). Equations (2.41) and (2.44) limit the maximal bid size dependent on the maximum up and down ramping abilities of each power plant.

Activation restrictions

$$G^{call,pos}_{b,p,t} \leq \sum_{bl} G^{resv,pos}_{b,bl,p,t} \qquad \forall b,p,t \qquad (2.45)$$

$$G^{call,neg}_{b,p,t} \leq \sum_{bl} G^{resv,neg}_{b,bl,p,t} \qquad \forall b,p,t \qquad (2.46)$$

$$\sum_{b} G^{call,pos}_{b,u,t} \leq g^{max}_{u} \cdot ON_{u,t} \qquad \forall u,t \qquad (2.47)$$

When reserve energy is activated, the positive and negative activation must always be smaller than the reserved amount for each power plant, hour and product as shown in (2.45) and (2.46). Equation (2.47) ensures that fast starting plants must start up to provide balancing energy. Note that the status of the power plants is not transferred between the stages of the multi-stage model but redetermined each stage,

transferring the amount of reserved capacity is sufficient to determine the power plant status. A fast-starting power plant that is in "Standby" in the reservation stage with reserved capacity might be set to "Online" during the activation stage. This way the actual startup cost of fast starting power plants can be accounted for in the model when the activations take place.

Storage restrictions

$$\begin{aligned} STOR^L_{s,t} - STOR^L_{s,t-1} &= G^{up}_{s,t} \cdot \eta_s - G^{down}_{s,t} + g^{nat}_{s,t} - G^{discard}_{s,t} \\ &\quad - \sum_b G^{call,pos}_{b,s,t} + \sum_b G^{Call,Neg}_{b,s,t} \cdot \eta_s \end{aligned} \qquad \forall s,t \quad (2.48)$$

$$v^{max}_s \geq G^{down}_{s,t} + \sum_{bl,b} G^{resv,pos}_{s,t,bl,b} \qquad \forall s,t \quad (2.49)$$

$$w^{max}_s \geq G^{up}_{s,t} + \sum_{bl,b} G^{resv,neg}_{s,t,bl,b} \cdot \eta_s \qquad \forall s,t \quad (2.50)$$

$$STOR^L_{s,t} - \sum_{bl,b,tt=t-12}^{tt=t+12} G^{resv,pos}_{s,tt,bl,b} \cdot \eta_s \geq l^{min}_s \qquad \forall s,t \quad (2.51)$$

$$STOR^L_{s,t} + \sum_{bl,b,tt=t-12}^{tt=t+12} G^{resv,neg}_{s,tt,bl,b} \leq l^{max}_s \qquad \forall s,t \quad (2.52)$$

In our model pumped hydro storage plants s take part in the balancing market. Equation (2.48) describes the storage level $STOR^L_{s,t}$ for every storage plant s that is dependent on the historic storage level $STOR^L_{s,t-1}$, pumping $G^{up}_{s,t}$ and generation activities $G^{down}_{s,t}$. Equations (2.49) to (2.52) limit the pumping, generation, and storage level as well as reserved balancing power. The restrictions on minimum and maximum storage level include the reserved positive and negative balancing reserves twelve hours prior and post the actual time step. This should represent the constraint that, within a time interval of 24 hours, the storage contains a sufficient amount of water to be able to deliver the balancing energy for both extreme cases of no or full activations of balancing reserves in all 24 hours.

Further restrictions

$$\begin{aligned} G_{p,t}, G^{rampup}_{p,t}, G^{rampdown}_{p,t}, G^{up}_{s,t}, G^{down}_{s,t}, STOR^L_{s,t} &\geq 0 \\ G^{ResvPos}_{b,bl,c,t}, G^{ResvNeg}_{b,bl,c,t}, G^{Call,Pos}_{b,p,t}, G^{Call,Neg}_{b,p,t}, Frq^{max}_{u,t} &\geq 0 \\ Chp^{storagelevel}_{chps,t}, Chp^{output}_{chps,t} &\geq 0 \end{aligned} \qquad \forall b,bl,p,t \qquad (2.53)$$

The constraints in (2.53) ensure positive values for some variables in the model.

2.3. Scenarios and data

We apply ELMOD-MIP to scenarios that represent the spot and balancing markets of Germany in 2013 and 2025. We use the year 2013 to estimate the effect of a potentially improved anticipation of the balancing energy reservation. Therefore, the scenarios for 2013 differ in the anticipation of balancing reserve activations. In contrast to assessing model improvements with historical data of 2013, we use the future year of 2025 to analyze the effect of a changing power plant portfolio and the possible participation of RES in the provisioning of balancing reserves. Therefore, in the 2025 scenarios we vary the participation of renewable energy sources in the balancing market.

As this modeling exercise uses a cost-minimization approach, the model results report a lower bound on the costs that can be anticipated in the balancing reserve market, not taking into account inefficiencies originating from the market design or strategic behavior.

In total we analyze seven scenarios:

- *2013*: power plant and renewable portfolio of 2013;
- *2013 Anticipation*: power plant and renewable portfolio of 2013 with anticipation of possible activation costs;
- *2025*: power plant and renewable portfolio of 2025;
- *2025 Wind5*: power plant and renewable portfolio of 2025 and wind turbines participating with 5 % of their capacity in providing negative reserves;
- *2025 Wind10*: power plant and renewable portfolio of 2025 and wind turbines participating with 10 % of their capacity in providing negative reserves;
- *2025 Wind5+*: in addition to the *2025 Wind5* scenario, wind turbines can offer 5 % of their capacity to provide positive and negative reserves;
- *2025 Wind10+*: in addition to the *2025 Wind10* scenario, wind turbines can offer 10 % of their capacity to provide positive and negative reserves.

2.3.1. Boundary conditions

Where possible, we use data available to the public. Load, balancing reserve requirements, cross-border exchange flows, and balancing reserve activations are based on historical time series from 2013. Renewable feed-in time series are based on TSO data from 50Hertz (2013), Amprion (2013), TenneT (2013), and TransnetBW (2013). Load time series are taken from ENTSO-E (2013-2016).

The power plant data for Germany is based on the DIW Data Documentation 72 by Egerer et al. (2014). Data from the Federal Network Agency (BNetzA, Bundesnetzagentur) has been used to augment the data further (BNetzA, 2014b; Umweltbundesamt, 2015). Cost assumptions for fuels and the CO_2 price are based on Egerer et al. (2014). Power plant characteristics are derived from the DIW Data Documentation 68 by Schröder et al. (2013a). Only power plants belonging to a portfolio that is pre-qualified are allowed to provide balancing reserves.[4]

In the application for 2025, most of the model's boundary conditions change. Prices for fuels and CO_2, the power demand, the power plant portfolio, and the renewable capacities are taken from scenario B of BNetzA (2014a). The 2013 application uses given historical data with exogenous exchange flows for the surrounding countries. In the 2025 application the cross-border flows are also exogenously given. These time series have been derived from a calculation using the model dynELMOD described in Gerbaulet et al. (2014) using the same 2025 input data plus additional information from the 2014 version of the Scenario Outlook and Adequacy Forecast (SOAF) by ENTSO-E (2014b) for all other European Countries.

The time-series of wind power feed-in has not only been scaled to adjust to the capacity anticipated in 2025, but has also been transformed to meet 2,000 full load hours (FLH), as technological advancements especially in the field of low-wind turbines are assumed in accordance with BNetzA (2014a, p. 111).

Data for reserved balancing power and activated balancing energy is taken from the official platform of the four German TSOs Regelleistung.net (2013). For positive secondary and tertiary reserves, 2.2 GW and 2.5 GW were contracted on average, respectively. For negative secondary and tertiary reserves these values differ, here 2.2 GW and 2.7 GW were contracted on average. As discussed in the introduction of this chapter, the influence of renewables on balancing demand is highly debated and uncertain.

2.3.2. Potentials and challenges for wind turbines providing balancing reserves

When considering the provision of balancing reserves from wind turbines, technical, regulatory and market-based challenges must be taken into account. The technical challenges of sufficiently fast response times and forecast accuracy have been addressed by most market participants: In 2015, the four German TSOs published a guideline for a two-year long pilot-test to pre-qualify wind turbines for minute reserve with

[4] The list of pre-qualified firms is derived from from `https://www.regelleistung.net/`. In technical terms, portfolios cannot be qualified but only single power plants. As this information is not provided on a power plant sharp basis, we abstract from this and use the portfolio sharp pre-qualification data.

the aim to determine how much of a wind turbine's capacity can be pre-qualified for balancing services (50Hertz et al., 2015). Pre-qualification of wind turbines to provide balancing reserves is the prerequisite of the participation. Technical and regulatory implementation hurdles have been taken (EWEA, 2014; Gesino, 2010; de Vos and Driesen, 2015), and in Germany two wind farms (86 MW) have been pre-qualified to provide up to 70 % of their installed capacity for negative TC (50Hertz, 2016). Götz and Baumgart (2014) assume that, for a security level of 99.994 %, up to 30 % of the entire German wind power can be used for balancing services when all turbines are pooled. Similar assumptions by Fraunhofer IWES (2014) assume a share of 10 % of wind capacity would be available for balancing services in a day-ahead regime. Depending on the scenario we assume a participation of wind power for positive and negative balancing reserves. For both SC and TC they can offer a total of 5 % or 10 % of their forecast feed-in in the 2025 application. We do not include the possibility of PV to provide (positive or negative) balancing reserves, as we assume that until 2025 a large share of PV installations are still decentral and not remotely controllable. Moreover, new battery storages could provide balancing reserves, still we do not assume new battery storages in our analysis for three reasons: First, prices in the SC and TC market are much lower than in the PC market, hence the provision of solely PC is the most likely option, where currently pilot projects exist. Second, the therefore required arbitrage profits from the spot market are not expected in the next ten years. Third, in line with reason two and forecasts for 2025 (compare 50Hertz et al., 2016a), not enough investments into battery storages are expected before 2040 in current long-term electricity investment models to play a substantial role for SC and TC balancing products.

2.3.3. Future balancing reserve demand

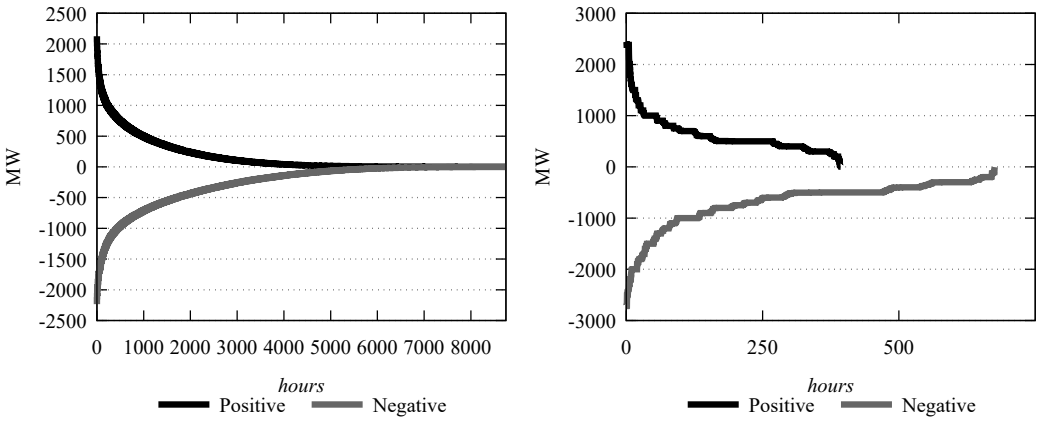
In the literature, the future balancing demand increase due to RES is thoroughly discussed. Most studies assume that due to the fluctuating nature of wind and solar power, the demand for balancing capacity reservation increases in order to compensate for forecast errors. Hirth and Ziegenhagen (2015) give an overview over the estimates in the literature: Here a reserve increase by 2 % to 9 % of additional wind power is expected in Brouwer et al. (2014), dena (2010), DLR (2012), Holttinen et al. (2011), and Lew et al. (2013). Ziegenhagen (2013) estimates an increase of 6 % of additional wind capacity; with additional solar installation this value decreases to about 4 %. Contrary to the literature results, the absolute value of reserved balancing capacity has decreased in the years 2010–2015, although renewable capacity has increased significantly in Germany.

This contradiction can be explained by a restructuring of the German intraday and balancing market which have lead to efficiency gains. Morbee et al. (2013) and Ortega-Vazquez and Kirschen (2009) present a further explanation and show show that until a high share of RES is reached, no significant effect on the demand for balancing reserves need to be expected.

While it can be assumed that the power plant portfolio of 2025 is significantly different from the 2013 portfolio, the uncertainty regarding the future balancing reserve demand can be allocated to different developments: On the one hand, improvements in quality and precision of renewable in-feed forecast could decrease balancing demand. On the other hand the reserve sizing mechanism influences the amount reserved substantially. With a static reserves sizing horizon, the amount of reserves is determined on a regular (e.g. quarterly) basis, whereas a dynamic reserves sizing horizon takes short term influences on the system such as renewable availability into account, possibly leading to a decreased reserves size. Breuer et al. (2013), Bucksteeg et al. (2016), and dena (2014) compare static and dynamic reserves sizing methods for future German balancing reserves and anticipate higher shares of renewable in-feed. The authors show that in case of dynamic reserves sizing the amount of required reserves only increases slightly compared to today's values. If static sizing was continued until 2030, where the amount of renewables is substantially higher than today, stronger increases up to a doubling of required reserves is estimated. Van den Bergh et al. (2016) develop a reserves sizing method in the context of cooperation between market zones, but conclude that the cost minimal approach is uncoordinated sizing, with joined activation across zones. Since most studies assume that until high shares of RES are reached, no significant influence on the balancing demand will be seen if dynamic reserves sizing is in place, and not to distort the results, we assume the same level of reserve demand for 2025 as for 2013.

The reserved balancing capacity is interlinked to the activated balancing capacity. Hence, the changing power plant portfolio does not only change the demand for reserved balancing capacity but could also change the probabilities of the activation of those capacities. On one hand, the magnitude of activation could increase due overlapping forecast errors for large RES capacities or decrease due to smaller power plant sizes. On the other hand, the relative volume of activation (FLH of balancing capacity) could increase due to an inevitable remaining forecast error of large RES capacities or could decrease due to new possibilities to trade closer to real time and even out previous forecast errors on intraday markets. Therefore the future magnitude and relative volume of activated reserve capacities is highly uncertain. In order not to distort the results, we assume no change for the probabilities of activation.

Figure 2.3 shows the duration curves of balancing reserve activations from 2013. Values above zero represent positive activations, whereas negative values represent



(a) Secondary Capacity (b) Tertiary Capacity

Figure 2.3.: Balancing reserve activation duration curves of 2013. Source: own depiction.

negative balancing reserve activations. The figures show that the secondary balancing energy demand can reach above 2 GW and below −2 GW in Germany.

While activations for secondary balancing energy occur throughout the year, tertiary capacity is used less frequently. At the same time, the peak activations for tertiary balancing energy are higher. Comparing these numbers to the peak load of about 83 GW and an overall energy demand of about 535 TWh in Germany shows that the energy activated on the balancing reserve markets is – by its nature – relatively small.

Data published by the TSOs shows the average values for balancing reserve activation within 15 minutes. These quarter hourly values are used to generate blocks with specific activation frequencies for each country, product, and direction. In this application we use ten different blocks for each balancing product. These activation frequencies are used to estimate the activation cost when reserving balancing power. See Section 2.2 for an explanation of activation frequencies and blocks. The quarter hourly values are also used to model the activation of balancing reserve during the call. This could result in an underestimation of possibly high ramping gradients as these activation could occur within seconds in practice.

2.4. Results and discussion

The application of ELMOD-MIP yields interesting insights into a possible development of the German balancing reserve market of 2025 and confirms an overall good

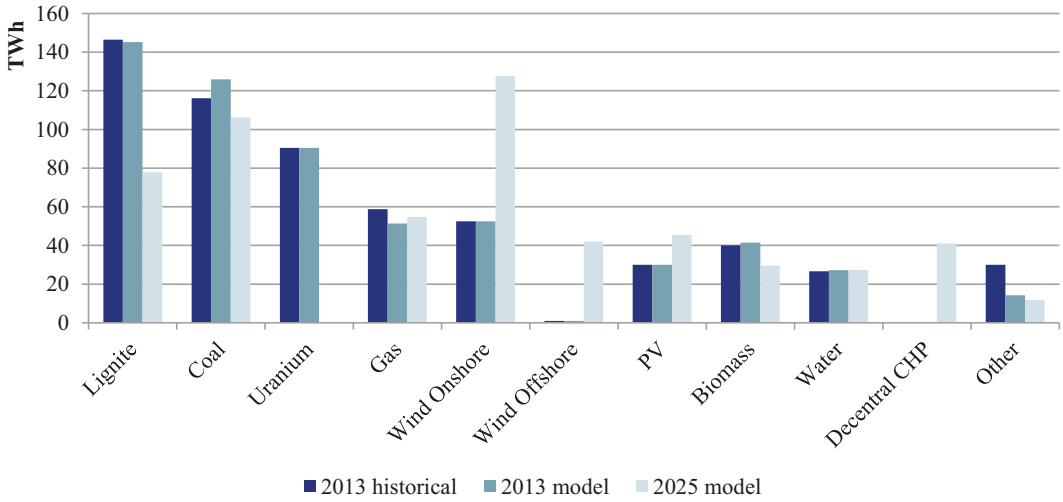


Figure 2.4.: Spot market generation by fuel for 2013 and 2025. This figure does not differentiate between the balancing reserve scenarios, as the effect on the spot market is minimal. Source: own depiction.

representation of the German electricity market of 2013, as the realized electricity generation levels of 2013 are met by the model values (Figure 2.4).[5]

In 2013, lignite and hard coal produced nearly half of the German electricity demand, followed by nuclear power and natural gas. RES accounted for around a quarter of the electricity demand. The generation levels of 2025 show strongly increased production by renewable energy sources compared to 2013, corresponding to the increase in installed capacity and improved FLH. Consequentially, also following the anticipated decrease in installed capacity of lignite and coal power plants, the production of lignite and coal-fired power plants is reduced significantly. No more nuclear electricity generation capacities are present in 2025. The gas-fired electricity generation level increases, as not only gas-fired power plants are used, but also "decentral CHP" generation is partly based on gas.

The model's spot price calculations also match the observed spot price values. The 2013 spot market price duration curve (Figure 2.5) as well as the average market price are nearly met by the model results with 36.5 €/MWh model average price compared to 37.8 €/MWh realized electricity price.

In 2025, the new power plant portfolio and increased generation from renewables lead to a different price duration curve with a slightly higher average price of 38 €/MWh, which corresponds to current forecasts for 2025 (cf. Oei et al., 2015b). Furthermore, we observe over 1,300 hours where the spot price is close to 0 €/MWh,

[5]Small deviations of the realized values to the model results are present, which are caused by different technology assignments for some power plants, especially regarding the categorization between "Coal" and "Miscellaneous." Furthermore, the production of gas-fired power plants is slightly underestimated.

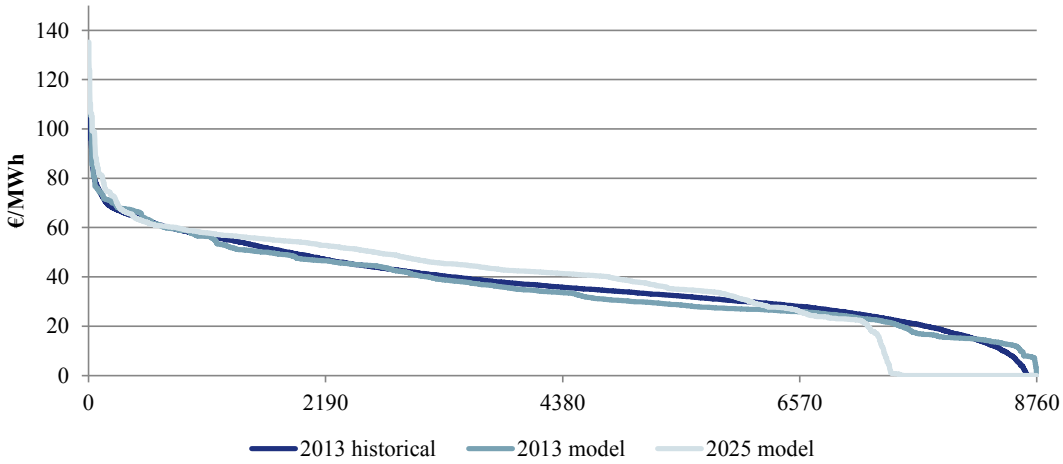


Figure 2.5.: Spot Price duration curves for 2013 and 2025. This figure does not differentiate between the balancing reserve scenarios as the effect on the spot market is minimal. Source: own depiction.

which is on the one hand caused by the uptake in renewable feed-in and on the other hand result of the model formulation, as the interaction with the neighboring countries is determined in a preparatory model run using the model dynELMOD described in Chapter 8.

2.4.1. Balancing reserve provision

Positive reserves are mainly provided by coal (40 %) and gas (40 %) in 2013. Lignite and pumped hydro storage capacities provide the remaining part of the reserves (Figure 2.6). Nuclear capacities do not participate in providing positive reserves. Similar technology shares for reservation of SC and TC are observable. For TC, more fast starting gas turbines are reserved that can be offline during the spot market dispatch. The inclusion of activation anticipation has a small but noticeable effect on the reservation by the different fuel types. Reservation of gas and oil fueled power plants is slightly reduced and replaced by water and coal fueled power plants, as their marginal costs, and therefore possible activation costs, are lower.

For the 2025 scenario, the reservation shifts towards lignite and pumped storage plant (PSP) reservation and fewer gas capacities. In comparison to 2013, lignite power plants are more often below full capacity in the spot market due to an increased variation of the residual load. Therefore they are able to provide more positive capacity without opportunity costs. In contrast, CHP power plants show higher FLH due to two factors: first, fewer CHP plants are in the market to provide heat. Second, more CHP plants are equipped with heat storage that allows for complete shutdowns

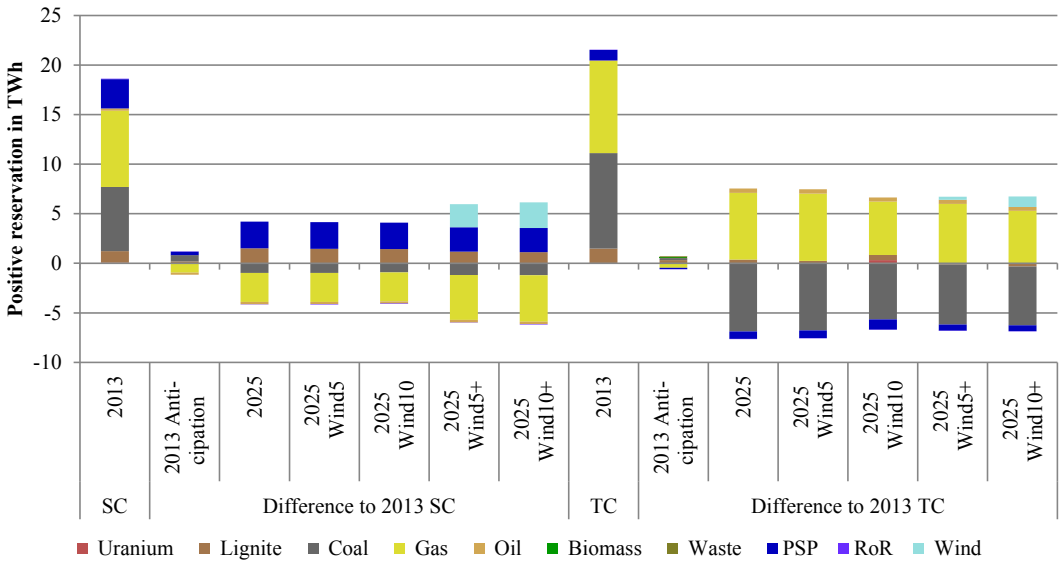


Figure 2.6.: Positive balancing capacity reservation by product, scenario and fuel for 2013 and 2025

when demand is low. These two factors lead to higher utilization, which in return leads to less options for reserve provision with low opportunity cost.

For TC the usage of gas-fired power plants increases in *2025* with the results of an almost exclusive provision of positive TC reservation by gas. This is caused by the high flexibility of gas-fired power plants compared to coal, allowing them to be offline and use their fast-starting gas turbines to start when needed. The possibility to use fast starting power plants is not given for SC, which explains the interesting contrary developments in SC and TC. However, in times with high spot market prices, gas fired power plants are used in both markets as their marginal cost are now close to the market price, which allows for cheap reserve provision. The PSP capacities are mostly used for SC reservation. The effect of the scenarios *2025 Wind5* and *2025 Wind10* on positive reservation is small as they only include participation of wind in the negative balancing market. Clearly a much larger effect can be observed in *2025 Wind5+* and *2025 Wind10+*. It is slightly different for SC and TC. For SC, wind replaces a significant share of gas reserves. The volumes are similar for the 5 % and 10 % wind participation. For TC, wind replaces less capacities as most of them are already provided by cheap offline gas turbines. The difference between 5 % and 10 % is bigger than for SC, indicating that first, costly SC is provided by wind and only when excess wind capacity is available the already cheap TC is replaced.

The reservation of negative balancing capacity (Figure 2.7) in the *2013* scenario is distributed between coal (30 %), lignite (29 %), run-of-river (18 %), natural gas (10 %) and PSP (7 %). Taking into account possible activation probabilities in the scenario *2013 Anticipation* alters the reservation towards more fossil based capacities,

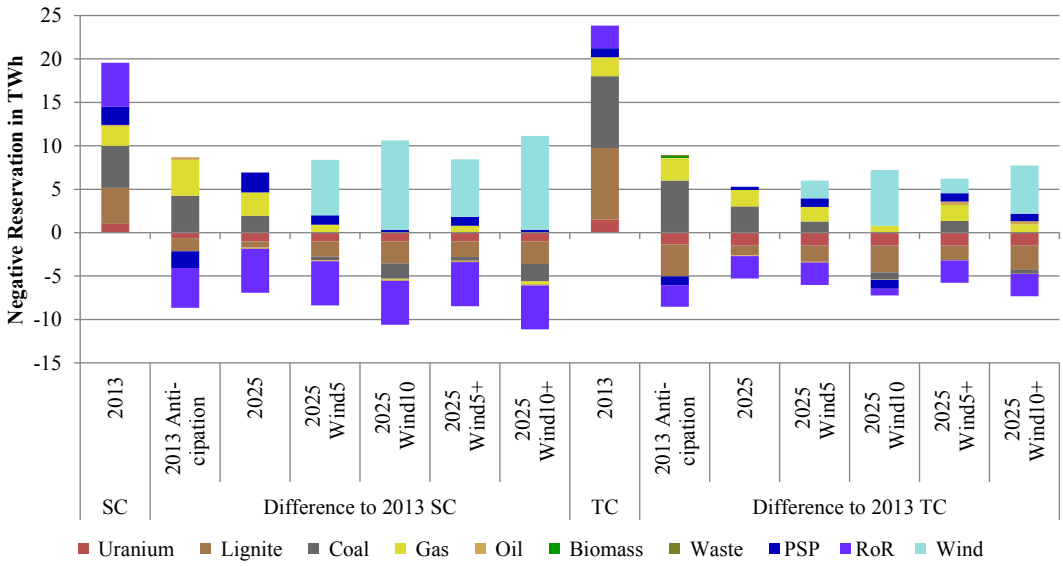


Figure 2.7.: Negative balancing capacity reservation by product, scenario and fuel for 2013 and 2025

as potential fuel savings in the case of activation are anticipated, which would not occur with run-of-river capacities.

In the *2025* case without wind, the reserved capacity also shifts to coal, gas, and PSP, reducing lignite and run-of-river reservation. The reduced FLH of lignite lead to less possibilities to provide negative reserves without additional costs. In contrast, one can see an increased provision by gas fired power plants, as these power plants are now producing due to a spot price above their marginal costs and hence above their minimum load. Therefore, they have the potential to ramp down and provide negative reserves.

With increased wind participation for negative reserves in the scenarios *2025 Wind5* and *2025 Wind10* wind is used increasingly and provides 53 % of the SC capacity and about 33 % of the TC capacity in the scenario *2025 Wind10*. The participation of wind turbines in providing negative reserves reduces mainly the provision of coal but for high shares also of PSP and gas. As expected, the provision of positive reserves by wind in the *2025 Wind5+* and *2025 Wind10+* scenarios does not have an significant influence on the provision of negative reserves.

2.4.2. The system cost of balancing reserves

Comparing the computed costs for reservation with the observed costs and between the scenarios provides insights whether the model is able to replicate the current market setting sufficiently well, and what the effect of the novel model formulation with activation anticipation is. Also, the cost estimate for 2025 can be analyzed.

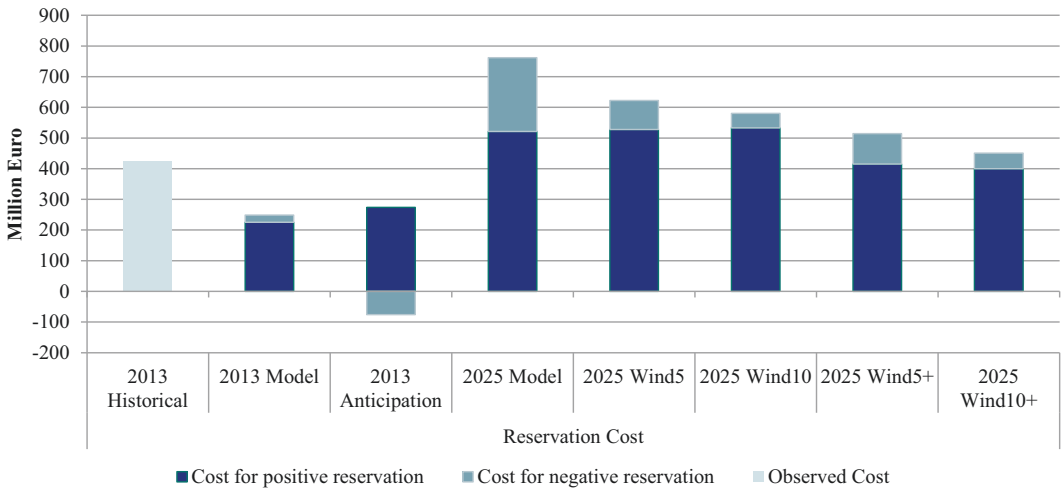


Figure 2.8.: Total cost for reserves provision by scenario for 2013 and 2025. Source: BNetzA (2015b) and own calculations.

Independent of the scenario, the calculated cost for reserving SC and TC balancing capacities in 2013 are lower than the 423 million € costs observed (Figure 2.8). This is mainly a result of the assumption of hourly reserve capacity reservation as well as underestimated costs for negative balancing capacity. In the current market setting, prices for negative reserves are not mainly driven by market fundamentals but also by market participant behavior and price expectations. Especially in a setting with many plants running at or near full capacity, the cost of providing negative balancing capacity should be close to zero. Thus, replicating the historical results in a fundamental electricity model is challenging.

While the cost for positive balancing capacity reservation in the scenario *2013* do not fully meet the values observed, the comparison with included anticipation in the scenario *2013 Anticipation* shows a slightly better approximation of the positive balancing reservation cost with 273 million €. Here, generation capacities with higher opportunity cost on the spot market but potentially lower anticipation cost are reserved. The overall calculated cost are still lower than observed, especially as the price for negative reserves is underestimated by the model.

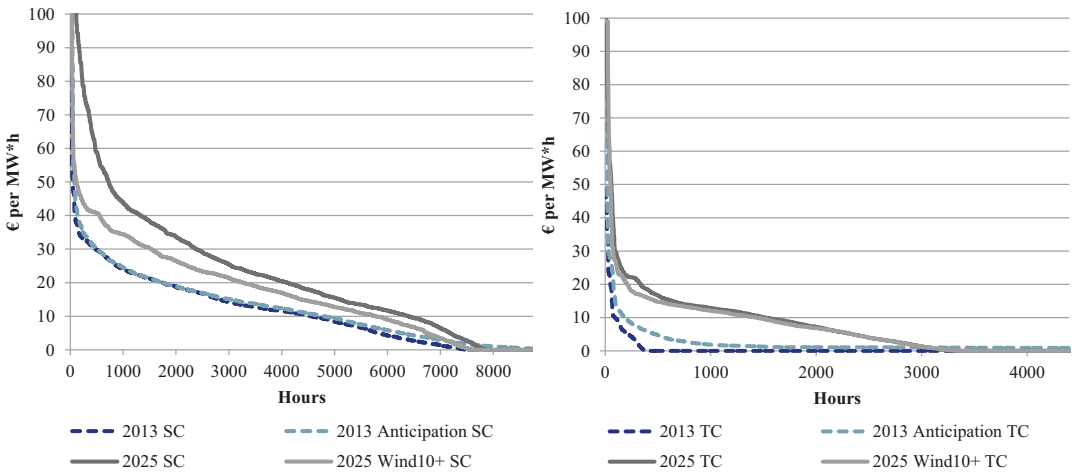
The cost estimate for negative reservation is not improved by the inclusion of anticipation. Here overall negative costs are observed, because hourly prices are often negative. This is caused by the anticipation of potentially saved fuel costs in the model, leading to a negative price in this fundamental model setting. Thus, while the overall reservation structure and prices for positive reserves are improved in the scenario *2013 Anticipation*, the representation of prices for negative balancing cannot be improved.

In 2025 we see an overall reservation cost increase throughout the scenarios. The reservation cost range between 761 million € in the *2025* scenario to 450 million € in the scenario *2025 Wind10+*. The overall cost increase can be explained by a lower supply for balancing capacity as a consequence of the changes in the German power plant portfolio. During times of very low residual load, power plants must now just be online to provide reserves, inducing high costs due to minimum load constraints. Additionally, the shift towards gas-fueled power plants increases the part load costs. Within the scenarios for the year 2025 the overall costs decrease with ascending wind participation as expected. Wind capacities mostly replace fossil capacities during times when residual demand is very low. During this time these capacities would not run normally (above minimum load) due to the low market price, except for providing reserves. Hence, this "unnecessary" generation cost can be avoided. The additional benefit of 10 % instead of 5 % percent of wind turbines participating is different for positive and negative reserves. While negative reserve cost are further reduced when increasing the number of participating turbines, the cost for positive reservation do not decrease substantially. Furthermore, the relative cost savings stemming from wind participation in negative reserves are higher than from participation in positive reserves, as for negative reserve provision, no ex-ante curtailment of wind feed-in is necessary. For positive reserve provision, wind feed-in must be curtailed to enable upward potential. Thus, the opportunity cost for providing positive reserves are much higher than for negative reserves. Therefore, only in situations with a very residual load close to or below zero (which are still rare in 2025) it is beneficial to provide positive balancing reserves with wind turbines. Hence, the resulting cost savings by wind providing positive reserves, are lower. In systems with a higher share of fluctuating RES and more hours with low residual load, the use of positive reserves by wind turbines become a sensible option.

In line with the reservation cost, the activation cost differ depending on scenario. The results show that in the *2013 Anticipation* scenario activation cost for positive and negative balancing energy can be reduced in comparison to the *2013* scenario by up to 10 %. For the *2025* scenario activation cost for positive and negative balancing energy are increasing by 15 %. These cost for negative balancing energy are significantly reduced with the participation of wind in the *2013 Wind5* scenario and *2013 Wind10* scenario. Similarly, the cost for positive balancing activation are significantly reduced in the *2013 Wind5+* scenario and *2013 Wind10+* scenario.

2.4.3. Prices on balancing reserve markets

We now analyze the price duration curves as well as the average reservation price for the balancing products. This allows further insights into the effect of the scenario



(a) Price of positive reservation SC (b) Price of positive reservation TC

Figure 2.9.: Price duration curves for positive reservation by product and scenario for 2013 and 2025. The scenario *2025 Wind5* is not depicted for clarity. The duration curve of *2025 Wind5* is directly between *2025* and *2025 Wind10*. Source: own calculations.

Table 2.1.: Average marginal prices for balancing capacity reservation by scenario

€/MW·h	Product	*2013*	*2013 Anticipation*	*2025*	*2025 Wind5*	*2025 Wind10*	*2025 Wind5+*	*2025 Wind10+*
Positive reservation	SC	11.66	12.87	23.30	23.49	24.32	17.68	17.13
	TC	0.40	1.59	4.14	4.21	4.72	4.06	3.82
Negative reservation	SC	1.03	-3.61	7.63	2.39	1.14	2.55	1.20
	TC	0.14	-0.39	3.84	2.03	1.06	2.08	1.14

Source: own calculation.

variations regarding the price distribution. Table 2.1 gives an overview of the observed average marginal prices for balancing capacity reservation. Looking at the market results for positive balancing capacity of *2013*, we observe an average marginal price for positive SC reservation of 11.66 €/MW·h. This comes close to the historical average of 12 €/MW·h (Figure 2.9a). The average marginal price for positive TC reservation is much lower with 0.4 €/MW·h (Figure 2.9b). Also the historical market results for positive TC reservation shows a much lower price than than SC, still the model price is significantly lower than the historical results.[6] In the scenario *2013 Anticipation* the average price for positive SC reserves increases as expected by 1 €/MW·h to 12.87 €/MW·h. On the right hand side the low prices increase

[6] In the current German balancing market pay-as-bid is used in contrast to the marginal prices reported in our model. According to Kahn et al. (2001) all pay-as-bid bids in such a market setting will converge towards the market clearing price in the long term, not taking into account risk-aversive behavior. Therefore, the marginal pay-as-bid price and our marginal price can be compared.

slightly. This is a result of the call anticipation, the peak prices remain unaffected, as other influencing factors are relevant here. The price duration curve for TC in *2013 Anticipation* shows higher prices overall, showing an improved representation of the historical results with 1.59 €/MW·h, almost matching the observed average of 1.51 €/MW·h of 2013.

In 2025, the average marginal price for SC increases to 23.3 €/MW·h, while prices for TC increase to 4.1 €/MW·h. With the participation of wind in the positive reserve provision the average marginal price for SC decreases to 17.7 €/MW·h for *2025 Wind5+* and 17.1 €/MW·h for *2025 Wind10+*. Therefore, only the load duration curve for the *2025 Wind10+* is shown. Especially the high prices for SC can be reduced with wind participation. Prices for TC decrease less heavily to 4 €/MW·h for *2025 Wind5+* and 3.8 €/MW·h for *2025 Wind10+*. As expected, the provision of negative reserves by wind turbines in the *2025 Wind5* and *2025 Wind10* scenarios does not have a significant impact on prices for positive reserves.

In 2025 the general price level is higher, and higher price peaks are observed. This price increase stems from different factors: First, the German power plant portfolio is characterized by higher average marginal cost than in 2013, which mainly applies to gas-fired power plants. Furthermore, the gas-fired power plants' relative part-load efficiency decrease is higher than for other plant types, leading to higher part load cost.[7] Second, more situations with very low residual load occur, in which no or very few dispatchable thermal power plants are online or have spare generation capacity. Thus, additional plants need to be started up and operating in minimum load just to provide available capacity for possible reserve energy activation.

Third, the increased flexibility of CHP plants in 2025 (e.g., due to additional heat storage) results in reduced online times and higher load factors during electricity production. Hence, CHP plants produce less often when their marginal costs are above the market price. Thus, the amount of must-run capacity is reduced in 2025, which would allow for an reserve provision without opportunity cost.[8]

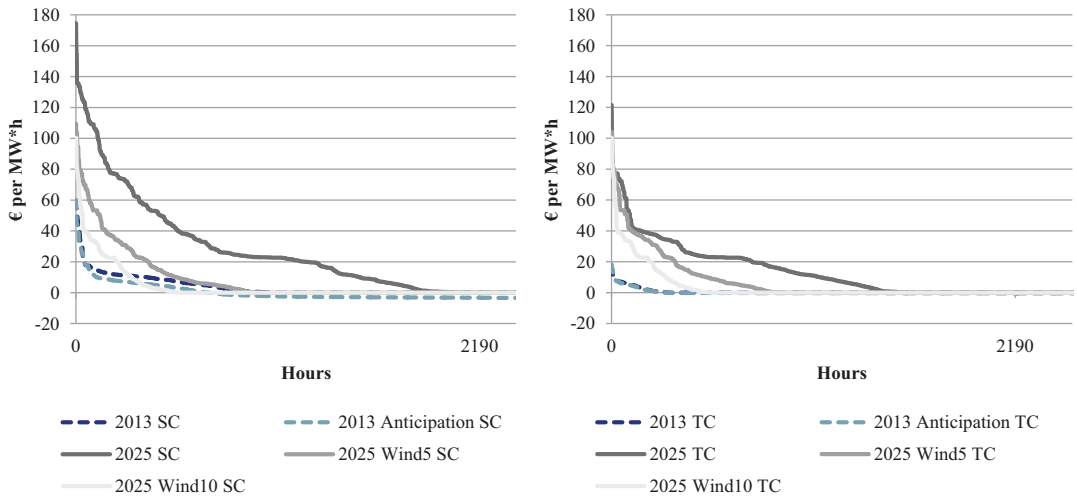
Analyzing the negative prices (Figure 2.10) for reserve capacity shows a different picture: In 2013 we observe an average marginal price for negative SC of 1.03 €/MW·h, which is significantly lower than the actually observed market outcome of 40 €/MW·h.[9] Hence, we find that prices for negative reserves are not fully replicable using a fundamental model, which is inline with current literature.[10]

[7] See Section 2.2 for an explanation on cost components driving the price of reserve capacity.

[8] See footnote 7.

[9] In the actual market outcome for 2013, the average marginal price for negative reserves of 40 €/MW·h is much higher than the average bid price of 8 €/MW·h. In the market for positive reserves the average marginal price and average price are much closer.

[10] This is confirmed by Bucksteeg et al. (2014) who compute prices for negative reserves close to zero in a fundamental model approach and thus only analyze the prices for positive balancing capacity.



(a) Price of negative reservation SC (b) Price of negative reservation TC

Figure 2.10.: Price duration curves for negative reservation by product and scenario for 2013 and 2025. Source: own calculations.

Looking at the results for negative reserves in the *2013 Anticipation* scenario we observe negative prices for a large percentage of hours. This is a result of the model formulation, as the potential fuel savings are included in the reservation price. In this case, the novel model formulation does not lead to more realistic price results.

In *2025* the average prices for negative SC increase to 7.63 €/MW·h; peak prices increase from 60 €/MW·h (*2013*) to 174 €/MW·h. Prices are still low in general, as prices above zero are observed in less than 2,000 hours. The inclusion of wind participation in the *2013 Wind5* and *2013 Wind10* scenarios influences the prices visibly, as the price averages are much lower with an average price of 2.39 €/MW·h and 1.14 €/MW·h, respectively. In contrast to positive reserves, additional wind turbines in the *2013 Wind10* scenario can further reduce the prices compared to *2013 Wind5* scenario.

For negative TC, average marginal prices close to zero are observable in *2013* that increase to 3.84 €/MW·h in the *2025* scenario. The *2025 Wind5* and *2025 Wind10* scenarios reduce the price for negative TC reservation again, to 2.03 €/MW·h and 1.06 €/MW·h, respectively. In line with the results for SC, additional wind turbines further reduce the prices. As expected, the provision of positive reserves by wind turbines in the *2025 Wind5+* and *2025 Wind10+* scenarios does not have a significant impact on prices for positive reserves.

The price increase for negative reserves in the *2025* scenarios stems from the fact that conventional generation is running at minimum load (or is even offline) in more hours. Thus, some plants must produce electricity only to provide negative reserves, even if their marginal cost are above the spot price. The provision of negative

balancing reserves by wind reduces these cost significantly, as in situations with low residual demand wind feed-in is often very high. This allows for large quantities of negative balancing reserves being provided by wind turbines, which in return allows for reducing the amount of conventional power plants that have to be online merely to provide negative reserves.

2.4.4. Discussion of limitations

This chapter's findings need to be discussed in the context of the model's limitations as well as assumptions regarding the regulatory and technical boundary conditions.

We abstract from any strategic behavior that the market participants might apply, which might lead to higher prices on the spot and balancing markets and could increase costs. Furthermore, we abstracts from some characteristics of the actual balancing market design, that includes product durations of more than an hour as well as portfolio bids, where an actor controlling multiple power plants can bid into the balancing market without revealing in advance which power plant will provide the balancing reserves. However, for power plants within large portfolios this approximation leads to no changes, only for power plants in small portfolios these approximation could lead to an overestimation on their flexibility. Together with the neglection of uncertainty of RES infeed and load realization, a perfect adjustment of the reserved capacities neglecting any market inefficiencies is possible. Thus, the true cost of the balancing reserve system is likely underestimated. The increasing market volume would also increase the absolute cost savings. Hence, the absolute cost savings observed in the model are a lower bound, as the relative cost savings are not changing, because the different scenarios are based on the same assumptions.

Apart from strategic behavior, most technical constraints can only be approximated in a large-scale unit-commitment model. This includes also limitations on wind turbine output when withholding capacity to provide balancing reserves. As the future output of a wind turbine always includes some level of uncertainty, it can be complicated to determine the capacity that must be withheld to provide balancing reserves with a sufficient high level of security. Thus, real opportunity cost of wind turbines providing balancing reserves, could be slightly higher, although the general picture will not change.

2.5. Conclusions

This chapter presents the fundamental market model ELMOD-MIP which includes a detailed approach to model balancing provision for 2013, and analyzes a future scenario for the German balancing market of 2025. ELMOD-MIP includes the

probability of reserve activation during the calculation of reserve capacity allocation. This allows us to closer approximate the behavior of market participants. In the future scenario of 2025, the influence of a changed power plant portfolio on prices and allocation of reserves is analyzed. Furthermore, the influence of wind power as a new market participant for the provision of positive and negative reserves is analyzed. The model shows a good representation of the spot and balancing markets. The novel approach leads to an improved representation of the historical market results for positive reserves, especially for TC. For negative reserves the representation cannot be improved substantially. Here, besides market fundamentals, strategic behavior and price expectations are important price drivers, which are hard to replicate in a fundamental electricity model.

The application of ELMOD-MIP to scenarios of the year 2025 shows an increase of prices for positive and negative reserves, when no entrance of new market participants is anticipated. With the participation of wind turbines the cost for balancing provision is reduced by 40 %, but remains above 2013 values. The relative cost savings stemming from wind participation are higher for negative reserves, as no previous curtailment of feed-in is required for reservation in contrast to positive reserve provision by wind turbines. The participation of wind turbines especially reduces the occurrence of peak prices for positive and negative reserves in 2025. This reduction effect occurs even with a relatively low share where wind turbines participate with only five percent of their capacity.

Further fostering the process of allowing wind turbines to participate in the German reserve market favorable. Although participation of wind turbines in balancing reserves is already reality, the current motions to adapt the current market setup to improve timing and flexibility of the auction process by decreasing lead times between bid and delivery, shorter product lengths, or an adapted bidding procedure to include marginal cost pricing could improve the market environment to enable the findings discussed in this chapter.

Chapter 3

Options for cross-border balancing reserve provision – A model analysis of electricity balancing cooperation arrangements in the Alpine region

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3.1. Introduction

One of the European Commission's goals is to establish an internal energy market for Europe. This includes a restructuring of the electricity market, laid out to a large extent in Directive 2009/72/EC and Regulation EC No. 714/2009. This exposes the European electricity system to significant changes, not only with respect to developments in generation and grid, but also to arrangements for the operation of the electricity system. In 2017, the European Network of Transmission System Operators for Electricity (ENTSO-E) published the final draft of the Network Code on Electricity Balancing (NC EB) which foresees arrangements to foster cross-border exchange of balancing services with the objective of lowering overall costs and increasing social welfare (EC, 2017). In line with the suggestions of the NC EB, in this chapter we analyze different forms of cross-border exchanges of balancing reserves with an application to the region of Austria, Germany, and Switzerland.

Increasing cross-border cooperation regarding balancing reserves is important because in the long term a high share of renewables will be reached, which could lead to higher balancing needs and lower balancing supply if the current balancing markets design remains unchanged. Borggrefe and Neuhoff (2011) see the upcoming importance of balancing markets with rising shares of wind penetration and propose a joint provision and adjustment of balancing services. While balancing markets have a much lower volume than the spot market, changes on balancing markets can also influence the spot market price. Wieschhaus and Weigt (2008) analyze these influences and show that an increasingly competitive balancing market also leads to lower prices on the spot market.

Balancing costs in Germany have been relatively constant to decreasing, although the renewable share is rising (Hirth and Ziegenhagen, 2015). This can partly be explained by the reorganization of the market design in Germany. Nevertheless dena (2014) and Holttinen et al. (2011) project rising balancing reserve requirements and specific costs for higher renewables shares if the market circumstances do not change. This phenomenon has not materialized in the market, although the share of renewables has increased substantially in recent years in Germany.

Balancing reserves stabilize the system's frequency of 50 Hz in the European electricity grid. In general, deviations from the nominal frequency can occur due to unexpected fluctuations in demand or generation. Three different types of reserve can be distinguished by their response time and length of activation: primary control (PC), secondary control (SC), and tertiary control (TC).[11]

[11] Throughout the literature different terms like balancing reserves, balancing capacity, control power, control energy are used. We will use the terms balancing reserves, balancing power and balancing energy that are used by ENTSO-E (2013a). The differentiation of the balancing power

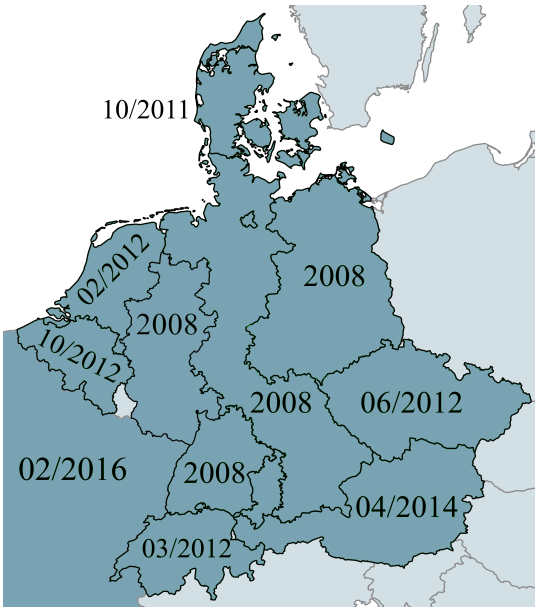


Figure 3.1.: TSOs' participation in the IGCC over time. The dates reflect the start of cooperation in the IGCC.

3.1.1. Cooperation efforts for balancing reserve procision in Europe

Currently, these products are auctioned on predominantly national markets with partly different procurement mechanisms. In Germany a joint balancing control area with joint coordinated procurement of secondary reserve capacity including all four German transmission system operators (TSOs) was established in 2010. This cooperation was extended in 2012 to the International Grid Control Cooperation (IGCC), see Figure 3.1. It is limited to the avoidance of counteractivation between two countries, called imbalance netting. Hence no joint procurement or activation of SC or TC takes place, as this could require the alteration of national framework conditions. Additional participants since 2012 are Energinet.dk (Denmark), Swissgrid (Switzerland), ČEPS (Czech Republic), Elia (Belgium), and TenneT TSO B.V. (the Netherlands). In April 2014 the cooperation was expanded to APG (Austria), and RTE (France) joined the cooperation in February 2016.

The IGCC is one of the most promising of ENTSO-E's cross-border electricity balancing pilot projects. Another leading balancing pilot project is the Trans European

products used in this chapter corresponds to the German variant. Thus, short-time load frequency control products such as frequency containment reserve (FCR) are PC, while automatic frequency restoration reserve (aFRR) is denoted as SC and manual frequency restoration reserve (mFRR) is denoted as TC in this chapter. Furthermore, replacement reserve (RR) are used to restore the required level of other reserves (FCR, aFRR, and mFRR) to be prepared for a further system imbalance. No comparable balancing product exists in Austria, Germany or Switzerland.

Replacement Reserves Exchange (TERRE) project, whose objectives is to establish a platform for all replacement reserve (RR) offers and to optimize the allocation of RR across the systems of various TSOs. It consists of TSOs in Great Britain, France, Spain, Portugal, Italy, Switzerland, and Greece (ENTSO-E, 2015b). A further advanced pilot project started in 2013 with the aim to establish one common market for the procurement of FCR based on a TSO–TSO model. Participants are currently Austria (APG), Denmark (Energienet.dk), the Netherlands (TenneT NL), Germany (50Hertz, Amprion, TenneT DE and TransnetBW) and Switzerland (Swissgrid). It is planned that Belgium (Elia) and France (RTE) will join the project in the future (ENTSO-E, 2015a).

Currently, several pilot projects tackle different balancing products (FCR, aFRR, mFRR, and RR), involving many TSOs and pursue diverse objectives (ENTSO-E, 2014a). These pilot projects have been established because in contrast to other European energy markets, where a rather clear target model exists, different forms for the provision and exchange of balancing services are still in discussion. This diversity highlights the challenge for harmonization (cf. ENTSO-E, 2012c).

To overcome this diversity the NC EB tries to set a framework for future balancing harmonization. It addresses the topics of i) imbalance settlement, ii) procurement of balancing services, and iii) reservation and use of cross-zonal capacity for balancing. It is binding for each TSO, distribution system operator (DSO), balancing service provider (BSP) and balancing responsible party (BRP) and should frame their settlement processes. To harmonize the process of balancing service exchange between two or more TSOs the concept of Coordinated Balancing Areas (CoBAs) is developed. Every TSO must cooperate with two or more TSOs in a CoBA by exchanging at least one standard product or through implementation of an Imbalance Netting Process. However there is a transition period of two years after the entry into force of the NC EB before this rule applies. After various consultations by the Agency for the Cooperation of Energy Regulators (ACER) the final draft of the NC EB was sent to the electricity cross-border committee of the European Commission (EC) before it entered the comitology process, through which it should become European law. (EC, 2017)

The TSOs from Austria, Belgium, Germany and the Netherlands form the "European X-border Project for Long term Real-time balancing Electricity market design" (EXPLORE) that aim at creating a consistent cross-border balancing market design for aFRR and mFRR in line with the definition of CoBAs described in the NC EB. Furthermore, it takes a special position, as this cooperation focuses not only on balancing markets, but also on interlinks with the spot markets. (50Hertz et al., 2016b)

3.1.2. Literature on cross-border cooperation for balancing reserve provision

In the literature several studies treat the issue of cross-border balancing cooperation. The major part of the studies apply numerical models, focusing on the Nordic electricity markets. In contrast to most of the literature we analyze the region of Austria, Germany and Switzerland. One the one hand, they share a long history of cooperation between their electricity systems and are working closely together in different balancing pilot projects (ENTSO-E, 2014a). On the other hand, their generation portfolios are divers regarding technologies and potentials for renewable energy sources (RES), which prospects significant efficiency gains when forming a cooperation.

Van der Veen et al. (2010) give an overview on cross-border balancing agreements and perform a qualitative analysis on different arrangements. They conclude that cross-border balancing agreements are generally beneficial but uncertainties exist regarding their impact depending on the resulting detailed balancing market design.

Neuhoff and Richstein (2016) confirm that notion but highlight the need to avoid lock-in effects arising from an evolutionary market design process. Instead, first a consistent blue-print for a future balancing market market should be created, that could in a second step be the basis to assess individual market designs.

A study for the EC analyzes the impacts of a European balancing market (Mott MacDonald, 2013). It studies different approaches to handle cross-border exchange of balancing services by applying empirical methods as well as quantitative simulations. The results show a gain in social welfare and additional advantages for the integration of RES. To reach this goal the study recommends a TSO-to-TSO platform with a Common Merit Order List (CMOL), harmonization of key elements, and “appropriate” bidding blocks.

Van den Bergh et al. (2016) analyze the coordinating the sizing, allocation and activation of reserves among market zones. The reserve coordination among zones is mainly limited by network constraints. Their model is formulated as a three-step approach: i) a reserve sizing module, ii) a day-ahead module which determines the optimal energy scheduling and reserve allocation and iii) a real-time reserve activation module. They apply the model to the Central Western Europe (CWE) electricity system. The highest benefits occur when reserves are jointly activated but not jointly sized and allocated. This counter-intuitive result is caused by simplified transmission constraints during sizing and allocating reserves. Therefore reserves are not guaranteed to be deliverable in the model.

A further approach to analyze the reserve procurement and transmission capacity reservation in the northern European power market is Gebrekiros et al. (2015b). The

authors also implement a three-step approach however with different objectives. In the first step the frequency restoration reserve (FRR) bidding price is determined on the power plant's opportunity cost. In the second step the TSO selects the cheapest FRR bids including cross-border capacities when transmission capacity is reserved. In the third step optimal dispatch is determined, taking into account the reserve and transmission capacity allocations. In a case study on the northern European power system balancing provision cost can be reduced when transmission capacity is reserved. With a transmission capacity reservation level of around 20%, total system cost tend to be the lowest.

Abbasy et al. (2009) analyze the effect of integrating balancing markets of Northern Europe. They show that balancing costs can be decreased by 100 million € in the region by increased integration. While overall cost are reduced, balancing power prices remain stable on average. A similar question is analyzed by Jaehnert and Doorman (2010). The authors show that increased integration of the Nordic and German balancing markets shows positive effects, but these are dependent on assumptions regarding the cost of regulation services. Farahmand and Doorman (2012) estimate cost savings of up to 400 million € per year resulting from an integration of the Nordic balancing market with the German balancing market.

Furthermore, van der Veen et al. (2011) show the positive effects of cross-border cooperation in providing balancing services, by an agent-based analysis for different agreements for integrating the Dutch, German, and Nordic balancing markets. Results indicate a 50% reduction of balancing cost resulting from the implementation of a common merit order list. Furthermore, Abbasy et al. (2011) analyze the effects of trading among BSPs and TSOs (i.e. foreign bidding) between Norway and the Netherlands. To simulate the change in market prices an agent-based model is used. They conclude that there is no general answer to whether a BSP-TSO model would result in too much shifted capacity (therefore increasing prices in the cheaper market) because this is dependent on the current situation of the spot market. The usage of an agent-based model allows to introduce strategic behavior and different players. However, it requires assumptions on the behavior of players, which can influence results to a great extent. Farahmand et al. (2012) compare the effects of a non-integrated and a fully-integrated balancing market in the Nordic region for a 2030 scenario. They apply a two-stage approach to model the spot and balancing market, which is similar to the approach applied in this chapter. Results show that possible cost saving opportunities due to balancing market integration that allow for less activation and cheaper reservation of balancing capacity exist.

Regional cooperation in the procurement of tertiary balancing capacity in the alpine region has been analyzed by Gerbaulet et al. (2012b) with the result, that common procurement leads to cost decreases in the region. Bilateral cooperations

can also lead to a decrease in total cost. The authors note that optimal allocation of interconnector (IC) capacity for the spot market and balancing services might gain significance in the future.

Besides the benefits of cooperation described above, pursuing cross-border balancing agreements might be a challenging task. A comprehensive study by Tractebel (2009) analyzes a pathway towards cross-border balancing agreements in Europe and demonstrates possible obstacles. Main prerequisites of cross-border harmonization are identified as common technical characteristics of balancing services and gate closure times, a common remuneration mechanism for balancing services, and a harmonization of imbalance settlement mechanisms. Possible inefficiencies and distortions due to insufficient harmonization of national market designs are analyzed by Vandezande et al. (2008). They recommend an implementation of cross-border balancing agreements with very low prerequisites to allow for a fast and functioning realization. Intensified harmonization should be done at a later stage.

Building upon the prevailing literature we analyze possible effects of the proposed NC EB for SC and TC, taking into account the cross-border lines and potential competing allocation objectives of the different energy markets of Austria, Germany, and Switzerland.

The remainder of this chapter is structured as follows: Section 3.2 describes the methodology applied in this chapter and underlying assumptions. The mathematical formulation of the modeling approach is explained in section 3.3. Section 3.4 describes the scenarios applied in the model. The data and application are presented in Section 3.5. In Section 3.6 the quantitative results are discussed, and Section 3.7 draws conclusions.

3.2. Methodology

We analyze the benefits stemming from regional cooperation between Austria, Germany, and Switzerland in the procurement of balancing services taking into account the suggestions of the NC EB. We only take into account the effects on SC and TC and neglect PC as its provision is already done jointly. Furthermore, the activation of PC is also done on a pro-rata basis within the entire synchronized grid as it is activated based on the grid's frequency.

We apply an extended variant of the model ELMOD-MIP that determines the cost-minimal power plant dispatch in the spot market under the assumption of perfect competition.

In our model two factors induce costs when reserving balancing capacity: On the one hand opportunity costs occur due to balancing restrictions on the available generation capacity, as capacity is either reserved in a power plant in case of positive

capacity reservation, or a must-run condition is introduced in case of negative capacity reservation. On the other hand activation of balancing reserves leads to costs, because additional fuel is required or deviations from the optimal power plant dispatch occur. Pumped storage and hydro reservoirs can also participate in the balancing reserve market. Although no actual fuel cost occur in these plants, the connected nature of the electricity system leads to opportunity costs that are taken into account as well.

This chapter neglects price markups for balancing capacity as it focuses on the inefficiencies that exist in the balancing markets devoid of strategic behavior. Historical price markups, that are used in the majority of the existing literature, might distort the model results significantly in case of market integration, as the markups are usually not endogenous to the model. This could lead to an overestimation of the cost saving potential. Therefore our results will show lower cooperation benefits, as the model setting is different in comparison to the existing literature.

The extension of ELMOD-MIP (a mixed integer linear program (MILP)) is also a multi-step model. The steps involved are shown in Table 3.1. For all steps the same model is used, but relevant variables and parameters are fixed or set to zero based on each step's goal.

Table 3.1.: Model steps

Step	Description
1. Reservation	Spot market dispatch is calculated given balancing capacity requirements. Cross-border capacities are reserved depending on the scenario.
2. Activation	balancing reserves is activated given the reservation done in the previous step. This is either conducted for each region or the whole balancing area depending on the scenario.

1. Reservation Step 1 optimizes the power plant dispatch for all countries, given the balancing capacity requirements. The cross-border transfer capacities are optimized depending on the scenario for electricity exchanges only, or for electricity and reserve exchanges jointly. The model does not consider the cost for possible activation at this stage.

2. Activation In step 2, the dispatch including the activation of balancing reserves is optimized. Here, the variables determining the reservation of balancing capacity are fixed in the model. Only power plants with reserved capacity can be dispatched for balancing reserve activations by the model. No uncertainty about future spot market outcomes is integrated at this point, hence load and RES feed-in are certain for all hours of the model.

In the current market design balancing capacity is reserved regularly for time periods between four hours and one week, depending on the product and region. Furthermore this reservation is allocated to the bidding firms. The firms can optimize the dispatch of their power plant portfolio at the time of delivery of the balancing energy. In our model we abstract from this setting, thus balancing capacity can be reserved for each power plant and hour separately. This results in a situation similar to a single big firm participating in a cost-minimizing behavior on the balancing markets.

Computational complexity

The problem is not solved for an entire year at once, but each week is solved separately with a two-day overlap[12] to cover a whole year. To generate storage levels and associated limitations for the starting and the end period of each period, we solve a limited version of the model for the entire model year prior to the actual calculations. This is necessary because large-scale reservoirs not only optimize their dispatch on a day-to-day basis but the reservoir level and inflows into these reservoirs are very different over the course of a year. This allows to parallelize the calculations and reduce the computation time for an entire year significantly. It is solved with the help of a unix cluster. Up to 50 nodes were used in parallel, each equipped with at least 16 GB of RAM and AMD or Intel processors of at least 2.6 GHz. Each calculation needs up to 20 hours. Thanks to parallelization each scenario can be calculated in less than 2 days.

3.3. Model implementation

We extend the model ELMOD-MIP to be able to represent cross-border interaction and reservation and activation of balancing reserves within a multi-market environment. This sections only shows the additions and alterations to the model.

The model's objective is to minimize total system costs, while clearing the spot market as well as the balancing market for the two balancing power products SC and TC. The model is solved in the General Algebraic Modeling System (GAMS) using the commercial solver CPLEX.

[12] See Barrows et al. (2014) for an analysis of time series partitioning and overlap times. The authors suggest the setting used in this chapter to achieve adequate solutions while achieving fast solution times.

Market clearing

$$
\begin{aligned}
0 = q^{spot}_{r,t} - \sum_{c \in r} G_{c,t} + \sum_{s} (G^{up}_{s,t} - G^{down}_{s,t}) \\
- g^{wind}_{r,t} - g^{pv}_{r,t} - g^{bio}_{r,t} - g^{water}_{r,t} - g^{waste}_{r,t} \qquad \forall r, t \qquad (3.1)\\
- g^{sewage}_{r,t} - g^{deposite}_{r,t} - g^{cb}_{r,t} + \sum_{rr} F^{spot}_{r,rr,t}
\end{aligned}
$$

$$q^{resv,pos}_{b,bl,r,t} = \sum_{p \in r} G^{resv,pos}_{p,t,bl,b} - \sum_{rr} F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall t, r, bl, b \qquad (3.2)$$

$$q^{resv,neg}_{b,bl,r,t} = \sum_{p \in r} G^{resv,neg}_{p,t,bl,b} - \sum_{rr} F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall t, r, bl, b \qquad (3.3)$$

$$q^{call,pos}_{b,r,t} = \sum_{p \in r} G^{call,pos}_{b,p,t} - \sum_{rr} F^{call,pos}_{b,r,rr,t} \qquad \forall b, r, t \qquad (3.4)$$

$$q^{call,neg}_{b,r,t} = \sum_{p \in r} G^{call,neg}_{b,p,t} - \sum_{rr} F^{call,neg}_{b,r,rr,t} \qquad \forall b, r, t \qquad (3.5)$$

The spot market is cleared by leveling load $q^{spot}_{r,t}$, generation $G_{c,t}$, storage $G^{up}_{s,t}$, $G^{down}_{s,t}$, renewable feed-in $g^{wind}_{r,t}$, $g^{sol}_{r,t}$, $g^{bio}_{r,t}$ and exchange flows $F^{spot}_{r,rr,t}$ for all time steps t and regions r, as stated in (3.1). Markets for positive and negative balancing capacity are cleared separately for each product b and activation probability block bl, by leveling demand $q^{resv,pos}_{b,bl,r,t}$, $q^{resv,neg}_{b,bl,r,t}$, reserves $G^{resv,pos}_{p,t,bl,b}$, $G^{resv,neg}_{p,t,bl,b}$, and cross-border flows to or from other regions $F^{bal,pos}_{b,bl,r,rr,t}$, $F^{bal,neg}_{b,bl,r,rr,t}$. This is shown in (3.2) and (3.3) for the reservation and (3.4) and (3.5) for the activation of balancing reserves.

Flow restrictions

$$f^{max}_{r,rr} \geq F^{spot}_{r,rr,t} + \sum_{b,bl} F^{resv,pos,ge0}_{b,bl,r,rr,t} - \sum_{b,bl} F^{resv,neg,le0}_{b,bl,r,rr,t} \qquad \forall r, rr, t \qquad (3.6)$$

$$-f^{max}_{r,rr} \leq F^{Spot}_{r,rr,t} + \sum_{b,bl} F^{resv,pos,le0}_{b,bl,r,rr,t} - \sum_{b,bl} F^{resv,neg,ge0}_{b,bl,r,rr,t} \qquad \forall r, rr, t \qquad (3.7)$$

$$F^{spot}_{r,rr,t} = - F^{Spot}_{rr,r,t} \qquad \forall r, rr, t \qquad (3.8)$$

$$F^{resv,pos}_{b,bl,r,rr,t} = - F^{resv,pos}_{b,bl,rr,r,t} \qquad \forall b, bl, r, rr, t \qquad (3.9)$$

$$F^{resv,neg}_{b,bl,r,rr,t} = - F^{resv,neg}_{b,bl,rr,r,t} \qquad \forall b, bl, r, rr, t \qquad (3.10)$$

$$F^{call,pos}_{b,r,rr,t} = - F^{call,pos}_{b,rr,r,t} \qquad \forall b, r, rr, t \qquad (3.11)$$

$$F^{call,neg}_{b,r,rr,t} = - F^{call,neg}_{b,rr,r,t} \qquad \forall b, r, rr, t \qquad (3.12)$$

$$F^{resv,pos,ge0}_{b,bl,r,rr,t} \geq F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall b, bl, r, rr, t \qquad (3.13)$$

$$F^{resv,neg,ge0}_{b,bl,r,rr,t} \geq F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall b, bl, r, rr, t \qquad (3.14)$$

$$F^{resv,pos,le0}_{b,bl,r,rr,t} \leq F^{resv,pos}_{b,bl,r,rr,t} \qquad \forall b, bl, r, rr, t \qquad (3.15)$$

$$F^{resv,neg,le0}_{b,bl,r,rr,t} \leq F^{resv,neg}_{b,bl,r,rr,t} \qquad \forall b, bl, r, rr, t \quad (3.16)$$

$$\sum_{bl} F^{Resv,Pos,ge0}_{b,bl,r,rr,t} \geq F^{call,pos}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (3.17)$$

$$\sum_{bl} F^{resv,pos,le0}_{b,bl,r,rr,t} \leq F^{call,pos}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (3.18)$$

$$\sum_{bl} F^{resv,neg,ge0}_{b,bl,r,rr,t} \geq F^{call,neg}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (3.19)$$

$$\sum_{bl} F^{resv,neg,le0}_{b,bl,r,rr,t} \leq F^{call,neg}_{b,r,rr,t} \qquad \forall b, r, rr, t \quad (3.20)$$

We distinguish three types of flows: Spot market flows $F^{spot}_{r,rr,t}$, flow reservation of balancing capacity $F^{resv}_{b,bl,r,rr,t}$, and flows induced by the activations of balancing reserves $F^{call}_{b,r,rr,t}$. The maximum flows between regions are limited in the positive (3.6) and in the negative direction (3.7). These flows consist of spot market flows as well as reserved capacity for balancing purposes if available in the scenario. Equations (3.8) to (3.12) ensure model symmetry. In order to avoid model-induced counteracting for the possible balancing flows only the positive or the negative part is included in these equations. Hence counter-balancing-flows can not increase the flow limit. The flows induced by the activation of balancing reserves must always be lower than the reserved capacity as show in (3.17) to (3.20).

Further restrictions

$$F^{Resv,Pos,ge0}_{b,bl,r,rr,t}, F^{Resv,Neg,ge0}_{b,bl,r,rr,t} \geq 0 \quad (3.21)$$

$$F^{Resv,Pos,le0}_{b,bl,r,rr,t}, F^{Resv,Neg,le0}_{b,bl,r,rr,t} \leq 0 \quad (3.22)$$

Equations (3.21) and (3.22) ensure positive or negative values for some variables in the model.

3.4. Scenarios

We study different levels of balancing market integration as suggested in the current version of the NC EB: i. *No Cooperation* as a base case, ii. *Imbalance Netting* only, iii. *Joint Activation* across borders, and iv. *Full Cooperation*. We assume perfect competition and the objective is to minimize total system cost while taking into account generation restrictions, reserve restrictions and flow limitations between different countries.

i. In the scenario *No Cooperation* every country procures and activates balancing services on its own. Cross-border flows on the spot market exist but the balancing markets are separated.

ii. The scenario *Imbalance Netting* adds limited cooperation between countries during the activation phase of balancing reserves. Procurement of balancing capacity takes place nationally like in scenario i., but imbalances are netted between countries when activations for balancing reserves occur and remaining free transmission capacity can handle the induced power flow of imbalance netting. This avoids unnecessary counteracting between countries.

iii. In the *Joint Activation* scenario this cooperation is further extended and the activation of balancing reserves is coordinated between countries. If cross-border capacity is available, balancing reserves can be activated within the country with the lowest cost. The procurement remains separate for each country.

iv. In the *Full Cooperation* scenario the coordination extends to the procurement of balancing capacity, building on the setup of scenario *Joint Activation*. The capacity reservation is conducted for the entire region given cross-border capacity restrictions. Hence the reservation of capacity for cross-border balancing flows competes with the spot market flows. This allows for interesting insights into the value of each kind of cross-border capacity, as the model determines the cost-minimal balance between spot market and balancing flow reservation.

The overall model structure is identical for all scenarios. The scenarios are differentiated by the available transfer capacity for balancing purposes and the netting of imbalances between countries. Spot market flows are only limited by the available net transfer capacities (NTCs) in all stages.

3.5. Data and application to model region

We apply the model to our region of interest consisting of Switzerland[13], Austria and Germany as shown in Figure 3.2. We use exogenous exchange flows for the surrounding countries. Changes to these exchange flows due to the inclusion and change of the balancing cooperation scheme are not taken into account.

Where possible, we use publicly available data. Load, balancing power reserve requirements, and balancing reserves activations are based on historical time series from 2013. Renewable feed-in time series are based on TSO data for Germany from 50Hertz (2013), Amprion (2013), TenneT (2013), and TransnetBW (2013). For

[13]Liechtenstein is incorporated into Switzerland for our analysis.

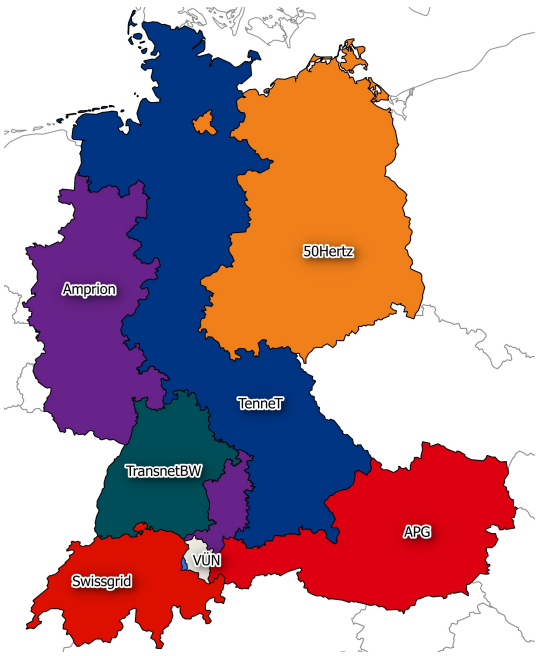


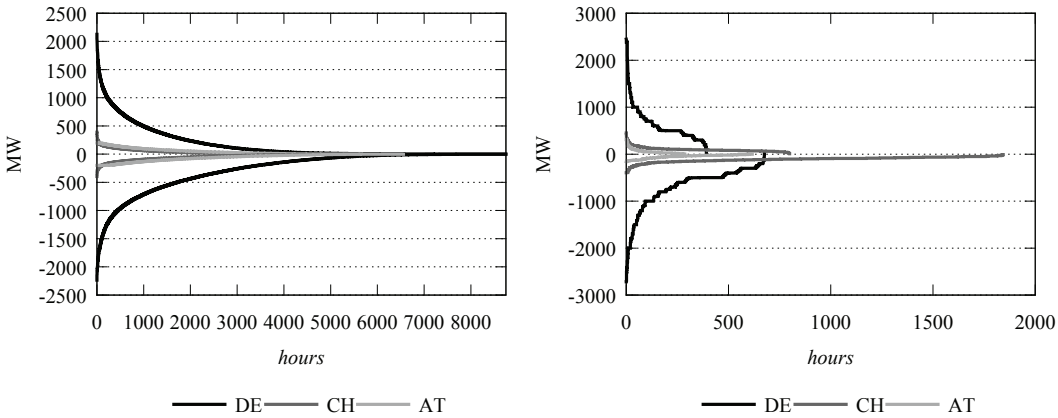
Figure 3.2.: TSOs in the model region

Austria and Switzerland the feed-in time series are approximated based on installed capacities and weather data. Hydro inflows for Austria are based on E-Control (2013) and for Switzerland on Bundesamt für Energie BFE (2013). Load time series for all regions are taken from ENTSO-E (2013-2016). The NTC between the countries is based on ENTSO-E (2016).

The power plant data for Germany is based on Egerer et al. (2014), and for Austria and Switzerland based on PLATTS (2011) as well as additional data from BFE (2014), BNetzA (2014b), and Verbund (2014). The transfer capacities between regions are based on NTC values from ENTSO-E (2013b). Cost assumptions for fuels and the CO_2 price are based on Egerer et al. (2014). Power plant characteristics are derived from Schröder et al. (2013a).

Data for necessary reserved balancing power and activated balancing reserves is taken from the official platform of the four German TSOs Regelleistung.net (2013) for Germany and from Swissgrid (2013) for Switzerland and E-Control (2013) for Austria. Figure 3.3 shows the duration curves of balancing reserves activations from 2013: Values above zero represent positive activations, whereas negative values represent negative balancing reserves activations.

The figures show that the balancing energy demand for SC can reach above 2,000 MW and below −2,000 MW in Germany. The balancing energy need in Austria and Switzerland is smaller, here the SC balancing reserves activations do not exceed ±400 MW for Switzerland and ±200 MW for Austria. While activations for secondary



(a) Secondary Capacity (b) Tertiary Capacity

Figure 3.3.: Balancing reserve activation duration curves of 2013.

balancing reserves occur throughout the year, tertiary capacity is used less frequently. At the same time the countries' peak activations for tertiary balancing reserves are higher. Comparing these numbers to the peak load of about 84 GW and an overall energy demand of about 535 TWh in Germany shows that the energy activated on the balancing reserve markets is – by its nature – relatively small. The same holds true for Austria with a peak demand of about 10.2 GW and a yearly consumption of 66 TWh as well as for Switzerland with a peak demand of 9.8 GW and a yearly consumption of 62 TWh.

In the calculations the balancing time series is aggregated from quarter hours to full hours, as the model's time resolution is one hour. This is achieved by taking the maximum activation of each hour and ensures that the necessary ramps that occur when balancing reserves are activated are also realized in our model. This slightly overestimates the total amount of activated balancing reserves.

3.6. Results and discussion

3.6.1. Cost for balancing reserve provision

The costs for balancing reserve provision are determined as the difference between the total system cost with and without inclusion of balancing reservation and activation. Our results indicate that increased cooperation in the provision of balancing reserves leads to a reduction in total cost, as depicted in Figure 3.4. The most beneficial scenario *Full Cooperation* leads to savings of up to 104 million € per year for the entire region. *Imbalance Netting* only has a minor cost effect, and *Joint Activation* leads to improvements in activation costs of about 30 million € savings per year.

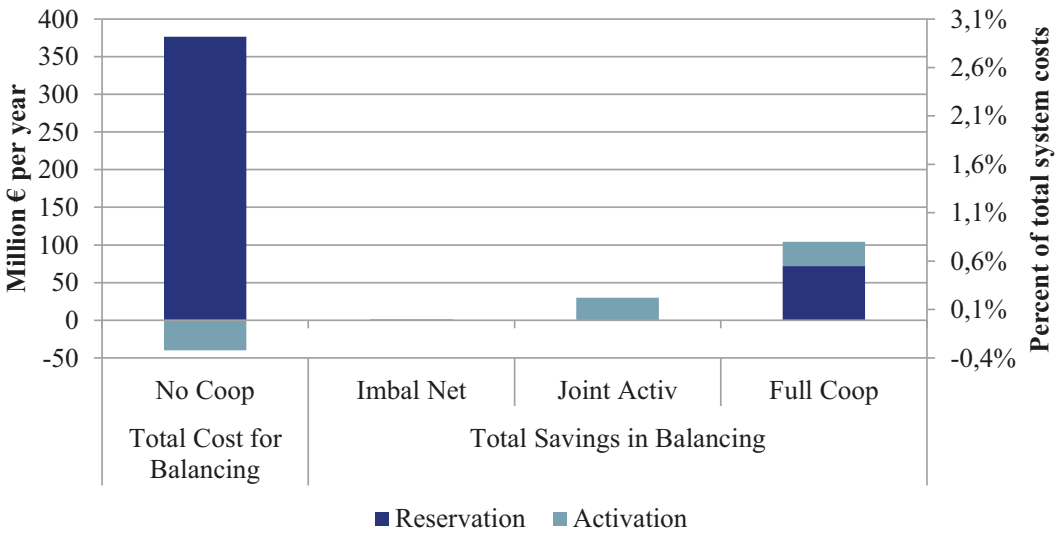


Figure 3.4.: Costs and savings

Only the scenarios *No Cooperation* and *Full Cooperation* are compared regarding the reservation outcome, as the reservation in the other scenarios is identical with the scenario *No Cooperation*. Here we see a cost improvement of 74 million € by coordinating the balancing procurement.

The difference in activation cost can be analyzed for all four scenarios. The total cost for activation of balancing capacities are negative in our application. This is caused by the fact that the total demand for negative balancing capacity is larger than positive balancing both for SC and TC in 2013. In case of negative balancing demand the model has the option to decrease the output of more expensive generation capacities, compared to the case of positive balancing demand. This causes the total cost of activation to be negative. This also reflected in historical prices of 2013, where the imbalance price during time of control zone shortage was also negative on average, fitting the results of our fundamental model.

Imbalance netting does not lead to significant activation cost improvements compared to existing projects. This deviation is partly caused by the fact, that the quarter-hours provided by the TSOs are already aggregated and hence less imbalance netting is possible. Further, the structure might be changed slightly. *Joint activation* shows cost improvements, as here the distribution of activated power plants can be optimized more with a higher degree of freedom. In the case of *Full Cooperation* the activation also leads to a further improvement in cost. In the *Full Cooperation* scenario not only the reservation but also the spot market as well as cross-border transmission capacity is optimized simultaneously. Despite the competition of the spot and balancing market for cross-border transmission capacity the overall cost in the *Full Cooperation* scenario, with partly reserved interconnectors are still lowest.

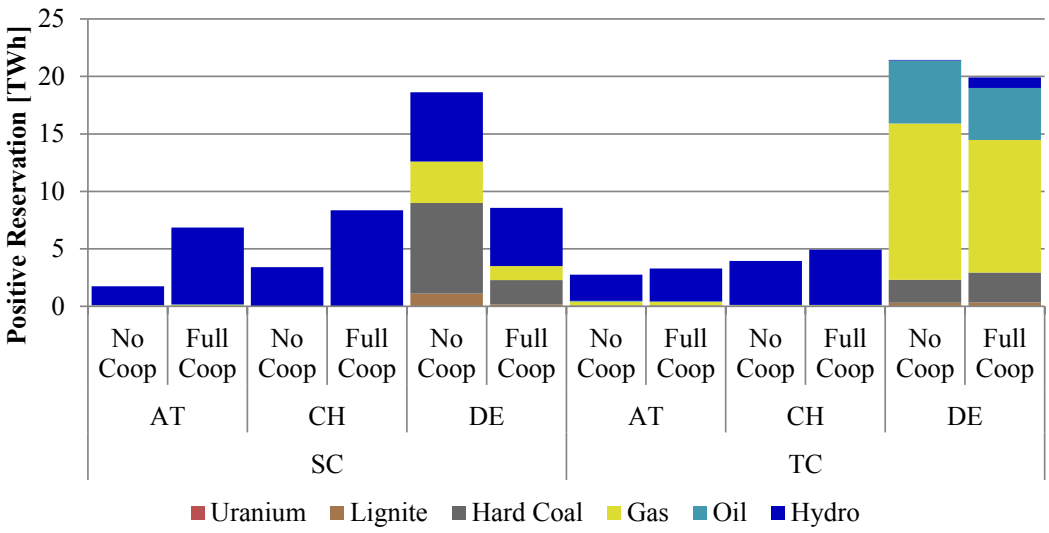


Figure 3.5.: Positive reservation

The much higher savings in the *Full Cooperation* justify the high complexity of the process. Therefore it would be beneficial to apply it to specific regions separately, as this requires a less complicated adaption and harmonization process.

The relatively small savings in comparison to the total cost are mainly caused by the small volumes of reserved balancing capacity in comparison to the spot market load. Furthermore only a small fraction of the reserved capacities is activated and causes direct generation costs.

Reservation of generation capacity for balancing power

When regional cooperation is in place a great impact on the amounts of reserved and activated balancing capacities can be observed. The scenario *Full Cooperation* – the only one that allows for inter-regional reservation – shows drastic changes of reserved capacities within the regions. Comparing the reservation of positive balancing capacity (Figure 3.5) between the *No Cooperation* and *Full Cooperation* scenarios shows a general trend towards generation both of SC and TC capacity from Germany towards Austria and Switzerland. We only analyze these two scenarios in this section, as the reservation result for the scenarios *Imbalance Netting* and *Joint Activation* is identical to the *No Cooperation* scenario. It is not only the amount of reserved capacity that allows for insights into a theoretically cost-optimal allocation of reserve capacity, but also the technologies that are used for capacity reservation.

In the case without cooperation, the demand for positive balancing capacity in Germany is met by hard coal, natural gas, and hydro capacities. For TC, oil and gas turbines capacities are also reserved, as these remain often unused and are not part of the least cost dispatch. They can be started sufficiently fast within the time

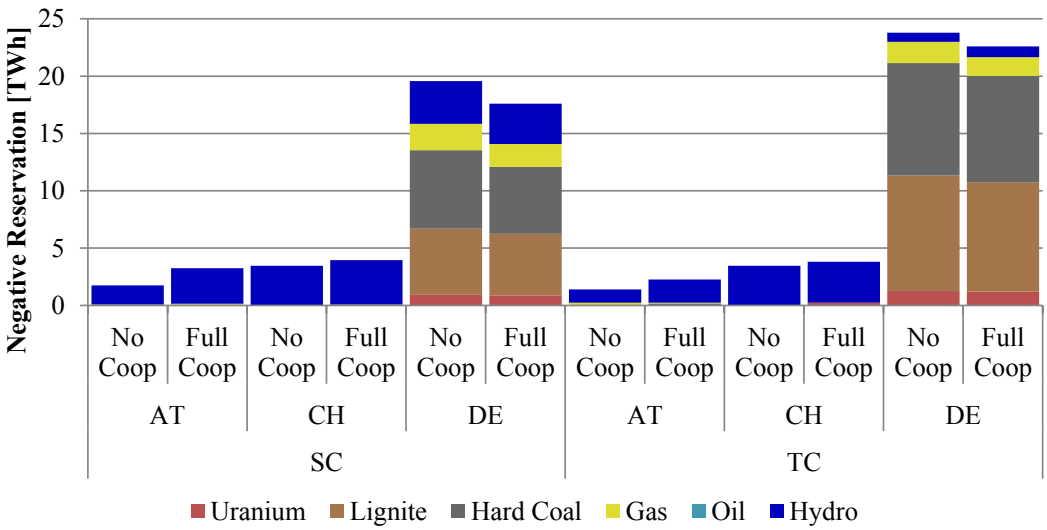


Figure 3.6.: Negative reservation

required to provide capacity for the TC product. Both in Austria and Switzerland, the demand for positive balancing capacity is almost entirely met by hydro based electricity generation technologies.

Reasons for the discrepancy can be explained by the difference in the generation portfolios between Germany and Austria/Switzerland. Germany's generation portfolio contains more fossil fueled generation capacities to serve its base load than its neighbors. Austria and Switzerland mainly rely on hydro power with theoretical zero marginal cost. Withheld generation capacity from run-of-river power plants (RoR) power plants is lost in our model as it can not be stored. Therefore it is not beneficial to provide positive reserve capacity with this technology. However it is beneficial to provide negative reserve capacity as these plants have no assumed minimum generation level. Due to their marginal cost close to zero, RoR are nearly always in the market. It is the other way around with pumped storage plants (PSPs), where unused water is not lost. Hence it is especially beneficial to use storage for positive reserve capacities. Furthermore, these plants also do not have minimum generation constraints and can can be started very quickly in our model. However, during hours with high spot prices, positive reserve is provided by power plants with marginal cost. During these times it is more efficient to reserve these plants and to use the storage plants in the spot market.

When the positive balancing capacity is reserved across the entire region, the reservation shifts toward more hydro capacity in Austria and Switzerland. About 50% of German SC capacity and 8% of German TC capacity are shifted towards Austria and Switzerland. This leads to significant transmission capacity reservation, analyzed in Section 3.6.1. This shift of SC is significantly higher than for TC as the provision

of TC is relatively cheap in Germany due to fast starting power plants. Hence the cost advantage of hydro power from Austria and Switzerland is less prevalent. This results in lignite in Germany not providing positive balancing capacity anymore, and the share of hard coal is also significantly reduced.

In the *No Cooperation* scenario hydro sources also provide negative reserves (Figure 3.6) for Austria and Switzerland. In Germany, hard coal and lignite power plants provide negative capacity, as those power plants are often part of the dispatch solution, and have the option to decrease the output of electricity without opportunity costs. This is often not the case for natural gas fired power plants, as these are further to the right in the merit order and also are often restricted by heat demand requirements.

The changes of coordinated reservation of negative balancing capacity are less distinct than in the case of positive balancing capacity. Only 10% of German SC capacity and 5% of German TC capacity is shifted towards Austria and Switzerland. The composition remains similar.

Activation of generation capacities to provide balancing energy

The activation of balancing reserves can be analyzed for all four scenarios. As balancing reserves activations are not constant but occur dispersed over time the values shown are significantly smaller than in Figures 3.5 and 3.6.

In the *No Cooperation* scenario, positive reserves in Austria and Switzerland are mainly provided by PSPs. In Germany, lignite and coal and PSP are the main provider for SC. For TC, fast starting natural gas plants are the main provider. In the *Imbalance Netting* scenario the SC and TC activations decrease by about 20% and 2% respectively (Figure 3.7). In all scenarios the amount of activated positive balancing reserves is decreased by imbalance netting as the effect remains also for the *Joint Activation* and *Full Cooperation* scenarios. The high cost decrease in the *Joint Activation* scenario (shown in Figure 3.4) stems from the shift away form gas fired activation in Germany for TC towards activations of hydro energy sources in Austria and Switzerland. In the *Full Cooperation* scenario in less coal and lignite is activated in Germany and shifted towards activations of hydro energy sources in Austria and Switzerland. This further shift in comparison to the *Joint Activation* scenario is due to the changes already occurring during reserving balancing capacities.

In the *No Cooperation* scenario, negative reserves in Austria and Switzerland are mainly provided by RoR. In Germany, hard coal, natural gas and RoR are the main provider. The development of negative activations throughout the scenarios show a similar overall picture as shown in Figure 3.8. Imbalance netting leads to an overall decrease in activations. These reduced activations are the base of the *Joint Activation* and *Full Cooperation* scenario. In the *Joint Activation* scenario, a shift from Austria

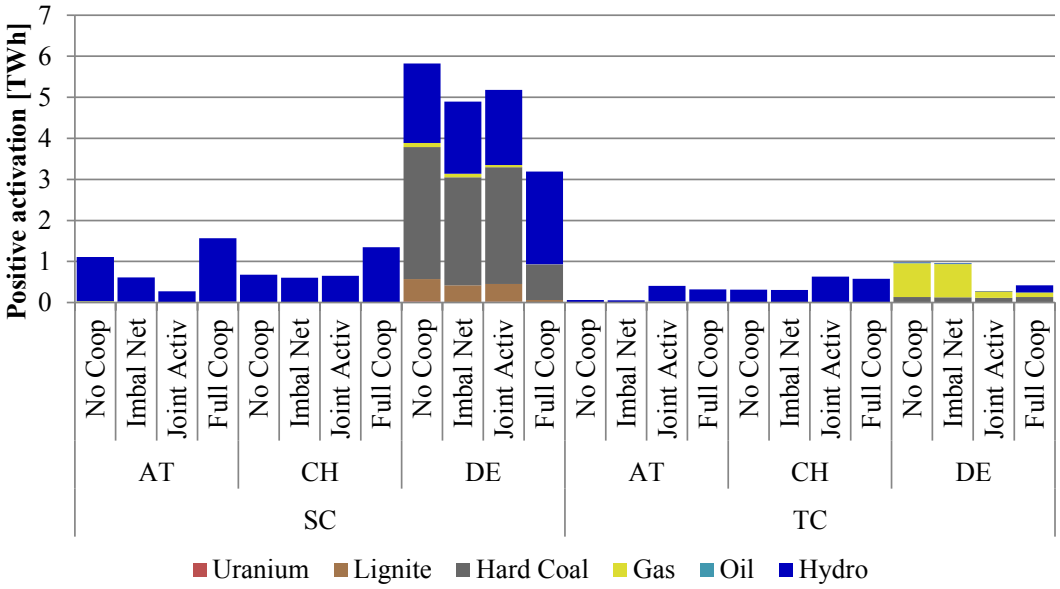


Figure 3.7.: Positive balancing reserve activations by scenario

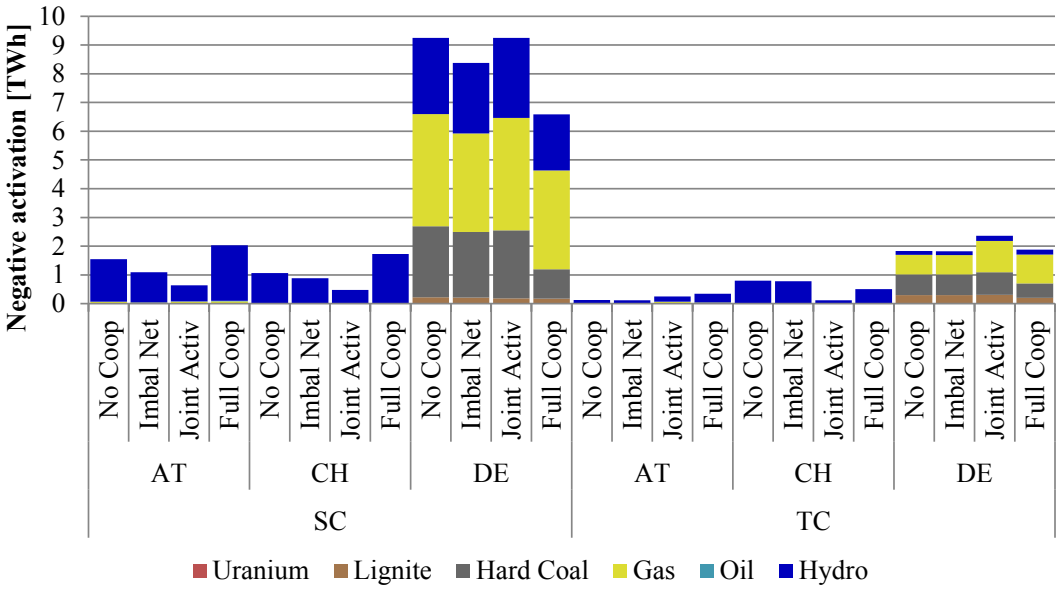


Figure 3.8.: Negative balancing reserve activations by scenario

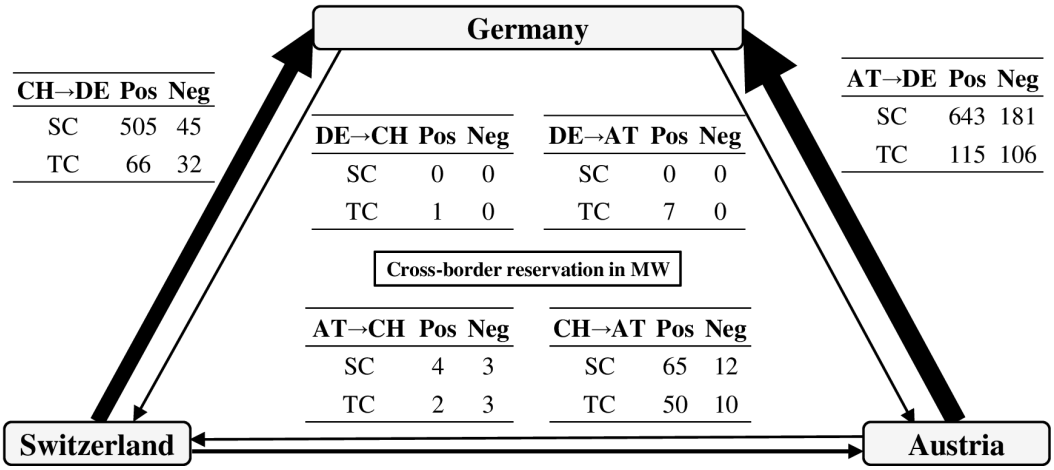


Figure 3.9.: Cross-border reservation of balancing capacity in the *Full Cooperation* scenario in MW

and Switzerland to Germany occurs. This initially counter-intuitive result stems from cost reduction of negative activation when applied to fossil generation technologies. Hence, increased activation of fossil generation capacities in Germany leads to an overall cost decrease. In the *Full Cooperation* scenario, the activations of SC also decrease and the lowest for Germany, as here the shift to Austria and Switzerland had already occurred during the reservation phase.

Cross-border analysis

In the *Full Cooperation* scenario, not only balancing capacities in neighboring zones are reserved, but also the cross-border grid must anticipate potential full activation of these capacities. Thus, cross-border transmission capacity is also reserved simultaneously.

Figure 3.9 shows the cross-border reservation of balancing capacity in the scenario *Full Cooperation*. We observe high reservation of IC capacity from Austria and Switzerland to Germany for positive reserves. While most of the capacity is reserved for positive SC. The IC capacity reservation from Germany to Austria and Switzerland is negligible, similarly for the capacity between Austria and Switzerland. The reserved IC capacity between Switzerland and Austria in contrast is small but significant and even between SC and TC.

The IC reservation for positive reserves between Austria and Germany accounts for up to 70% of the total IC capacity. The IC reservation for positive reserves between Switzerland and Germany accounts for up to 80% of the total IC capacity. At first, this seems quite high as the volumes in the balancing market are usually low compared to the spot market. However the IC reservation occurs in the opposite

direction of the normal prevalent spot market flows, as Germany regularly exports to Austria and Switzerland. Therefore the IC reservation for positive balancing services does not compete with spot market flows and hence does not increase total spot market costs.

For negative reserves we observe a very similar pattern of IC capacity reservation as just shown for positive reserves. However the level of IC capacity reservation is much lower. A reservation of IC capacity for negative reserves leads blocks the IC in the opposite direction. Hence, the negative reserves that are "flowing" from Austria and Switzerland towards Germany reduce the IC capacity from Germany to Austria and Switzerland. Therefore the IC capacity reservation occurs parallel to the direction of normally prevalent spot market flows. Hence, the reservation for negative balancing services competes with spot market flows and therefore potentially increases spot market cost. Therefore the IC capacity is only reserved during times of very high reservation prices or untypical spot market flow directions. As these situations occur less often, the average reservation of IC capacity is lower than for the positive reserves.

Results show, that often spot and reserve market see flows going in different directions. Electricity is exported from Germany while at the same time reserves are imported to Germany. During these times, spot market prices in Austria and Switzerland are higher than in Germany, leading to these spot market flows. But why does it then makes sense to withhold generation capacity in these countries to provide reserves for Germany? The type of generation capacity reserved in Austria and Switzerland induces this result: In Austria and Switzerland, mostly storage capacities are reserved for balancing. These capacities do not generate electricity during these time, as their water value is above the current spot market price. Therefore, they do not face opportunity cost when providing balancing reserves. Those reserve capacities will then be procured in Germany.

In the *Full Cooperation* scenario described above, the reservation of the activation of balancing reserves is always within the limit of the NTC, as activation must always be lower than the reservation. In contrast, the *Joint Activation* scenario allows for activation of balancing reserves across borders without prior IC capacity reservation. Therefore, only capacity that is not used in the spot market is used for balancing purposes.

3.6.2. Model limitations

Our model allows capacity reservation on an hourly basis. Together with the neglection of uncertainty of renewable energies in-feed and load realization, a perfect adjustment of the reserved capacities is possible. Thus, the true cost of the electricity system are

likely underestimated. Furthermore the benefits shown by our results are generated under the assumption of a social planner. We abstract from any strategic behavior that the market participants might want to apply, which would lead to higher prices on the spot and balancing markets and would increase costs. Network constraints are approximated using a transport model, hence loop flows and line specific limitation are not analyzed.

3.6.3. Implementation issues

When analyzing possible benefits of market reforms the cost and effects of implementation must also be addressed. *Imbalance Netting* requires the least technical and regulatory interventions. Furthermore is is already implemented in various balancing exchange cooperations like the IGCC. *Joint Activation* has similar technical prerequisites, and the implementation is therefore not critical from a technical perspective. In line with *Imbalance Netting*, *Joint Activation* is also already applied in different balancing pilot projects. In contrast, the implementation of *Full Cooperation* with joint procurement is more complex, both from technical but also from regulatory aspects. It requires the harmonization of balancing products and regulations. These challenges are partly addressed in the NC EB. Furthermore these requirements can be reduced when using a TSO–TSO model. The technical complexity regarding the adequate sizing of reserves across zones remains. The change of capacity reservation also shifts BSP rents and possibly influences the spot markets.

3.7. Conclusion

In this chapter we analyze regional cooperation scenarios on the balancing reserve market. The motivation for our analysis stems from "Network Code Electricity Balancing" by ENTSO-E which is close to implementation as of early 2017. It introduces various regulations to increase cross-border exchange of balancing reserves and should lead to lower overall balancing cost.

We estimate the efficiency increases for different levels of regional cooperation on the secondary and tertiary control markets of Austria, Germany, and Switzerland. We apply a fundamental electricity sector model with unit-commitment constraints and endogenous flows.

The model results confirm the expectations that increased cooperation in balancing markets is highly beneficial. The degree of cost savings depends on the depth of cooperation. The *Imbalance Netting* scenario show only minor cost savings, which can be largely increased by *Joint Activation*. The largest benefits can be gained in the *Full Cooperation* scenario. However, this requires the reservation of IC capacity

for balancing purposes, which could influence spot market cost. Therefore the IC capacity reservation is mostly done against the direction of regularly spot market flows, hence no competition rises. Only occasionally, when high reserve prices occur, IC capacity is reserved in the same direction as spot market flows. This coordinated procurement and cross-border capacity reservation mostly shifts capacity reservation from Germany towards Austria and Switzerland. These shifts are largely driven by the countries' different power plant portfolios. Coordinated procurement and cross-border activation also cause transfers of producers' rents. Thus, the resulting distributional effects need to be analyzed carefully.

Chapter 4

Power system impacts of electric vehicles in Germany: Charging with coal or renewables?

This chapter is based on Applied Energy 156, 185–196 (Schill and Gerbaulet, 2015b); DIW Berlin Discussion Paper No. 1442 (Schill and Gerbaulet, 2015a). Findings and policy implications are published in the DIW Wochenbericht 10/2015 *Speicher und Elektrofahrzeuge im Stromsystem* (Schill et al., 2015b) as well as the DIW Economic Bulletin 17/2015 *Power System Impacts of Electric Vehicles* (Schill et al., 2015a).

4.1. Introduction

The use of electric vehicles (EVs) is set to increase substantially in many countries around the world (OECD and IEA, 2013). Electromobility may bring about numerous benefits, such as lower emissions of various air pollutants and noise, increasing energy efficiency compared to internal combustion engines, and the substitution of oil as the main primary energy source for road transport. A massive uptake of electric vehicles may also have a strong impact on the power system. The effects on power plant dispatch, system peak load, and carbon emissions depend on both the power plant fleet and the charging mode of electric vehicles (cf. Hota et al. 2014).

In this chapter, we study possible impacts of future electric vehicle fleets on the German power system. The German case provides an interesting example as the government has announced ambitious targets of becoming both the leading manufacturer and the lead market for electric vehicles in the world (Bundesregierung, 2011). Moreover, the German power system undergoes a massive transformation from coal and nuclear toward renewable sources, also referred to as Energiewende. We carry out model-based analyses for different scenarios of the years 2020 and 2030, building on detailed vehicle utilization patterns and a comprehensive power plant dispatch model with a unit commitment formulation. We are particularly interested in the impacts of electric vehicles on the system's load duration curve, the dispatch of power plants, the integration of fluctuating renewables, and carbon dioxide (CO_2) emissions under different assumptions on the mode of vehicle charging.

Previous research has analyzed various interactions of electric mobility and the power system, covering purely battery-electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), and/or range extender electric vehicles (REEVs). Kempton and Tomić (2005) first introduce the vehicle-to-grid (V2G) concept and estimate V2G-related revenues in various segments of the United States (U.S.) power market. In the wake of this seminal article, a broad strand of related research has evolved. Hota et al. (2014) review numerous model analyses on the power system impacts of electric vehicles and group these into different categories, e.g., with respect to the assumed type of grid connection and the applied methodology.

One strand of the literature deals with power system implications of different charging strategies. Wang et al. (2011) examine interactions between PHEVs and wind power in the Illinois power system with a unit commitment approach. They show that smart coordinated charging leads to a reduction in total system cost and smoother conventional power generation profiles. Kiviluoma and Meibom (2011) model the power costs that Finnish owners of electric vehicles would face by 2035. In case of optimized charging, power prices turn out to be rather low as cheap generation capacities can be used. Loisel et al. (2014) analyze the power system impacts of

different charging and discharging strategies of battery-electric vehicles for Germany by 2030. Distinguishing between grid-to-vehicle (G2V) and V2G, they also highlight the benefits of optimized charging, yet conclude that V2G is not a viable option due to excessive battery degradation costs. Kristoffersen et al. (2011) as well as Juul and Meibom (2011) and Juul and Meibom (2012) also find that EVs provide flexibility mostly by optimized charging activities and not so much by discharging power back to the grid.

Another strand of the literature focuses on the interactions of electric vehicles with fluctuating renewables and emission impacts. Lund and Kempton (2008) analyze the integration of variable renewable sources into both the power system and the transport sector. They find that EVs with high charging power can substantially reduce renewable curtailment and CO_2 emissions. Göransson et al. (2010) carry out a comparable case study for Denmark, also concluding that system-optimized PHEV charging can decrease net CO_2 emissions. In a more stylized simulation for Denmark, Ekman (2011) highlights the potential of EVs to take up excess wind power. Guille and Gross (2010) focus their analysis on PHEV-related potentials for smoothing variable wind generation. Sioshansi and Miller (2011) apply a unit commitment model to analyze the emission impacts of PHEVs with regard to CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_x) in the Texas power system. Imposing an emission constraint on PHEV charging activities, they show that specific emissions may be reduced below the ones of respective conventional cars without increasing recharging costs substantially. For the case of Ireland, Foley et al. (2013) show that off-peak charging is the most favorable option with respect to cost and CO_2 emissions. Using an agent-based model, Dallinger et al. (2013) find that smart EV charging can facilitate the integration of intermittent renewables both in California and Germany by 2030. Schill (2011) analyzes the impacts of PHEV fleets in an imperfectly competitive power market with a Cournot model and finds that both welfare and emission impacts depend on the agents being responsible for charging the vehicles, and on the availability of V2G. Doucette and McCulloch (2011) notes that the CO_2 mitigation potential of photovoltaics (PVs) is highly dependent on the existing power plant portfolio and concludes that additional decarbonization efforts might be needed to obtain CO_2 emission reductions.

We aim to contribute to the cited literature in several ways. First, the unit commitment approach used here is particularly suitable for studying the interactions of EVs with fluctuating renewables. It considers the limited flexibility of thermal power generators and is thus more suitable to capture the potential flexibility benefits of EVs compared to linear dispatch models such as Ekman (2011), Göransson et al. (2010), Loisel et al. (2014), Lund and Kempton (2008), and Schill (2011). Next, the hourly patterns of electric vehicle power demand and charging availabilities used

here are considerably more sophisticated than in some of the aforementioned studies, e.g., Ekman (2011) and Foley et al. (2013). In contrast to, for example, Loisel et al. (2014), we moreover consider not only BEVs, but also PHEVs/REEVs. What is more, we do not rely on a stylized selection of hours in particular seasons or load situations (e.g. Wang et al. 2011), but apply the model to all subsequent hours of a full year. We further present a topical case study of the German Energiewende for the years 2020 and 2030 with up-to-date input parameters as well as a stronger deployment of renewables than assumed in earlier studies, and with a full consideration of the German nuclear phase-out. Next, we do not only distinguish between the two stylized extreme cases of fully cost-optimized and completely non-coordinated charging, but also include additional analyses with intermediate modes of charging, which appear to be more realistic. This is made possible by drawing on a novel formulation of EV charging restrictions. Finally, we study the effects of electric vehicles not only for a baseline power plant fleet, but also for cases with adjusted renewable generation capacities. This allows assessing the potential benefits of linking the introduction of electric mobility to a corresponding expansion of renewable power generation.

The remainder is structured as follows. Section 4.2 introduces the methodology. Section 4.3 describes the scenarios and input parameters. Model results are presented in Section 4.4. The impacts of model limitations on results are critically discussed in Section 4.5. The final Section 4.6 concludes. Further, the Appendix B presents a description of the optimization model, dispatch outcomes without EVs, and the results of additional sensitivity analyses.

4.2. Methodology

We use a numerical optimization model that simultaneously optimizes power plant dispatch and charging of electric vehicles. The model determines the cost-minimal dispatch of power plants, taking into account the thermal power plant portfolio, fluctuating renewables, pumped hydro storage, as well as grid-connected electric vehicles. The model has an hourly resolution and is solved for a full year. It includes several inter-temporal constraints on thermal power plants, such as minimum load restrictions, minimum down-time, and start-up costs. The model is formulated as a mixed integer linear program (MILP) with binary variables on the status of thermal plants. In addition, there are special generation constraints for thermal plants that are operated in a combined heat and power mode, depending on temperature and time of day.

The model draws on a range of exogenous input parameters, including thermal and renewable generation capacities, fluctuating availability factors of wind and solar power, generation costs and other techno-economic parameters, and the demand for

electricity both in the power sector and related to electric vehicle charging. As for the latter, we draw on future patterns of hourly power consumption and charging availabilities derived by Kasten and Hacker (2014). Hourly demand is assumed not to be price-elastic. Endogenous model variables include the dispatch of all generators, electric vehicle charging patterns, dispatch costs, and CO_2 emissions.[14]

We use a standard unit commitment model approach. The basic formulation is provided in Appendix B.1. In the following, we highlight the equations that deal with electric vehicles. EV-related sets, parameters and variables are listed in Table B.1 in Appendix B.1. Exogenous parameters are in lower case letters, endogenous continuous variables have an initial upper case letter, and binary variables are completely set in upper case letters. The set ev represents the different EV profiles in the model. Eq. (4.1) is the cumulative EV energy balance. The battery charge level $Chargelev_{ev,t}$ is determined as the level of the previous period plus the balance of charging and (price-inelastic) consumption in the actual period. The charge level of PHEV/REEV is also influenced by conventional fuel use $Phevfuel_{ev,t}$. Importantly, only electric vehicles of the PHEV/REEV type may use conventional fuels, so $Phevfuel_{ev,t}$ is set to zero for purely battery-electric vehicles (4.2). In order to ensure a preference for using electricity in PHEV/REEV, we penalize the use of conventional fuels with $penalty^{Phevfuel}$ in the objective function (Eq. (B.1) in Appendix B). Eqs. (4.3) and (4.4) constitute upper bounds on the cumulative power of vehicle charging and the cumulative charge level of vehicle batteries. Note that the parameter $chargemax_{ev,t}$ assumes positive values only in periods in which the EV is connected to the grid. Non-negativity of the variables representing charging, charge level, and conventional fuel use is ensured by Eqs. (4.5-4.7). In addition, the model's energy balance (Eq. (B.14) in Appendix B) considers the additional electricity that is required for charging electric vehicles $\sum_{ev} Charge_{ev,t}$ in each hour.

$$\begin{aligned} Chargelev_{ev,t} &= Chargelev_{ev,t-1} + Charge_{ev,t}\eta_{ev} \\ &\quad - cons_{ev,t}n_{ev} + Phevfuel_{ev,t} \end{aligned} \qquad \forall ev, t \qquad (4.1)$$

$$Phevfuel_{ev,t} = 0 \; if \; phev_e v = 0 \qquad \forall ev, t \qquad (4.2)$$

$$Charge_{ev,t} \leq chargemax_{ev,t}n_{ev} \qquad \forall ev, t \qquad (4.3)$$

$$Chargelev_{ev,t} \leq batcap_{ev}n_{ev} \qquad \forall ev, t \qquad (4.4)$$

$$Charge_{ev,t} \geq 0 \qquad \forall ev, t \qquad (4.5)$$

[14] We only consider G2V and abstract from V2G applications, as previous analyses have shown that the potential V2G revenues are unlikely to cover related battery degradation costs (cf. Loisel et al. 2014). Kempton and Tomić (2005), Andersson et al. 2010, Lopes et al. (2011), and Sioshansi and Denholm (2010) argue that V2G may be viable for providing spinning reserves and other ancillary services.

$$Chargelev_{ev,t} \geq 0 \qquad \forall ev, t \qquad (4.6)$$

$$Phevfuel_{ev,t} \geq 0 \qquad \forall ev, t \qquad (4.7)$$

Eqs. (4.8) and (4.8) are only relevant in the case of not fully cost-driven charging, i.e., if $fastchargegoal$ is exogenously set to a positive value. Eq. (4.8) makes sure that the vehicle will be charged as fast as possible after it is connected to the grid. This is operationalized by determining the difference between the desired and the current battery charge level. If the battery level is below the target, fast charging is enforced, i.e., the binary variable $FULLCHARGE_{ev,t}$ assumes the value 1. Eq. (4.9) then enforces charging to be carried out with full power. Note that this model formulation is very flexible. It allows not only representing the two extreme modes of charging, i.e., fully user-driven or fully cost- driven[15] charging; by assigning any real number between 0 and 1 to, $fastchargegoal$ any desired target level of fast battery charging may be specified. For example, if $fastchargegoal$ is set to 0.5, vehicle batteries have to be charged with full power until a charging level of 50% is reached. After that, the remaining battery capacity may be charged in a cost-optimal way. We focus on the two extreme charging modes in the model analyses, i.e., set $fastchargegoal$ to 0 (fully cost-driven) or 1 (fully user- driven), respectively, in most scenarios. In addition, we carry out additional analyses with values of 0.25, 0.5 and 0.75 (see Section 4.3).

$$\begin{aligned} 0 \leq\ & batcap_{ev} n_{ev} FULLCHARGE_{ev,t} \\ & - Chargelev_{ev,t} - batcap_{ev} n_{ev} fastchargegoal \end{aligned} \qquad \forall ev, t \qquad (4.8)$$

$$0 \leq Charge_{ev,t} - FULLCHARGE_{ev,t} chargemax_{ev,t} n_{ev} \qquad \forall ev, t \qquad (4.9)$$

4.3. Scenarios and input parameters

We apply the dispatch model to various scenarios. First, we distinguish different developments with regard to electric vehicle deployment:[16] a reference case without electric vehicles, a Business-as-usual (BAU) scenario and an "Electric mobility$^+$" (EM$^+$) scenario for the years 2020 and 2030. The BAU scenario assumes an EV stock of 0.4 million in 2020 and 3.7 million in 2030. The EM$^+$ scenario assumes a slightly increased deployment of electric vehicles with a stock of 0.5 million EV by 2020 and 4.8 million by 2030. This is made possible by additional policy measures such as a feebate system, adjusted energy taxation and ambitious CO_2 emission targets (for

[15] According to the objective function (B.1) presented in Appendix B, the model minimizes the costs of dispatch. This includes fuel and CO_2 costs as well as start-up costs. Capital costs are not relevant for the optimization under the assumption of existing generation capacities.

[16] In doing so, we draw on the scenarios developed by Kasten and Hacker (2014) in the context of the European research project DEFINE. `https://www.ihs.ac.at/projects/define/`.

further details, see Kasten and Hacker 2014). These scenarios are solved for all hours of the respective year. In addition, we carry out six additional model runs for the EM^+ scenario of the year 2030 with additional renewable capacities (RE^+). These capacities are adjusted such that their yearly generation exactly matches the yearly power demand of EVs. We assume that the additional power either comes completely from onshore wind, or completely from PV, or fifty–fifty from onshore wind and PV.

Within the scenarios BAU, EM^+, and RE^+, we further distinguish the two extreme charging modes described in Section 4.2. EVs may either be charged in a completely user-driven mode or in a completely cost-driven mode. User-driven charging reflects a setting in which all electric vehicles are fully recharged with the maximum available power as soon as these are connected to the grid. This mode could also be interpreted as a "plug-in and forget" charging strategy by the vehicle owners. In contrast, the cost-driven charging mode reflects a perfectly coordinated way of charging that minimizes power system costs. It could also be interpreted as system-optimized charging or market-driven charging under the assumption of a perfectly competitive power market. Such a charging strategy could be enabled by smart charging devices and may be carried out by power companies, specialized service providers, or vehicle owners themselves. In the real world, some intermediate modes of charging between these extremes may materialize. To approximate these, the 2030 EM^+ scenarios are additionally solved with fast charging requirements of 25%, 50%, and 75%, respectively. Table 4.1 gives an overview of all model runs.

Regarding exogenous input parameters, we draw on several sources. First, we use DIW Berlin's power plant data-base, which includes a block-sharp representation of thermal generators in Germany. Blocks with a capacity smaller than 100 MW are summed up to 100 MW blocks in order to reduce numerical complexity. Assumptions on the future development of the German power plant fleet are derived from the grid development plan (NEP, Netzentwicklungsplan).[17] This plan is drafted on a yearly basis by German transmission system operators for a time horizon of 10 and 20 years. After a series of revisions and public consultations, the NEP serves as the basis for German federal network planning legislation. We largely draw on the 2013 version (50Hertz et al., 2013b) regarding thermal and renewable generation capacities, fuel and carbon prices (Table 4.2), and specific carbon emissions.[18]

As the NEP 2013 only provides generation capacities for the years 2011, 2023, and 2033, we linearly interpolate between these years to derive capacities for 2020 and 2030. Nuclear power is phased-out according to German legislation. Pumped

[17] Netzentwicklungsplan (NEP) in German.

[18] More precisely, we draw on the medium projections called "B 2023" and "B 2033", which are deemed to be the most likely scenarios. We also draw on the 2012 and 2014 versions of the NEP in some instances, e.g., regarding 2010 generation capacities as well as 2012 offshore wind capacities 50Hertz et al. (2012, 2014).

Table 4.1.: Scenario matrix.

EV scenario	Charging mode	Generation capacities		2010	2020	2030
No EVs		Baseline		x	x	x
		RE$^+$	100% Wind			x
			50% Wind/PV			x
			100% PV			x
			100% Wind			x
			50% Wind/PV			x
			100% PV			x
BAU	User-driven	Baseline			x	x
	Cost-driven				x	x
EM$^+$	User-driven	Baseline			x	x
	75% fast charge					x
	50% fast charge					x
	25% fast charge					x
	Cost-driven				x	x
	User-driven	RE$^+$	100% Wind			x
			50% Wind/PV			x
			100% PV			x
	Cost-driven		100% Wind			x
			50% Wind/PV			x
			100% PV			x

Source: Own assumptions.

Table 4.2.: Fuel and carbon prices.

	Unit	2010	2020	2030
Oil	EUR_{2010}/t	446	543	663
Natural gas	EUR_{2010}/MWh_{th}	21	25	26
Hard coal	EUR_{2010}/t coal equ.	85	80	86
Lignite	EUR_{2010}/t MWh_{th}	2	2	2
CO_2 certificates	EUR_{2010}/t	13	24	41

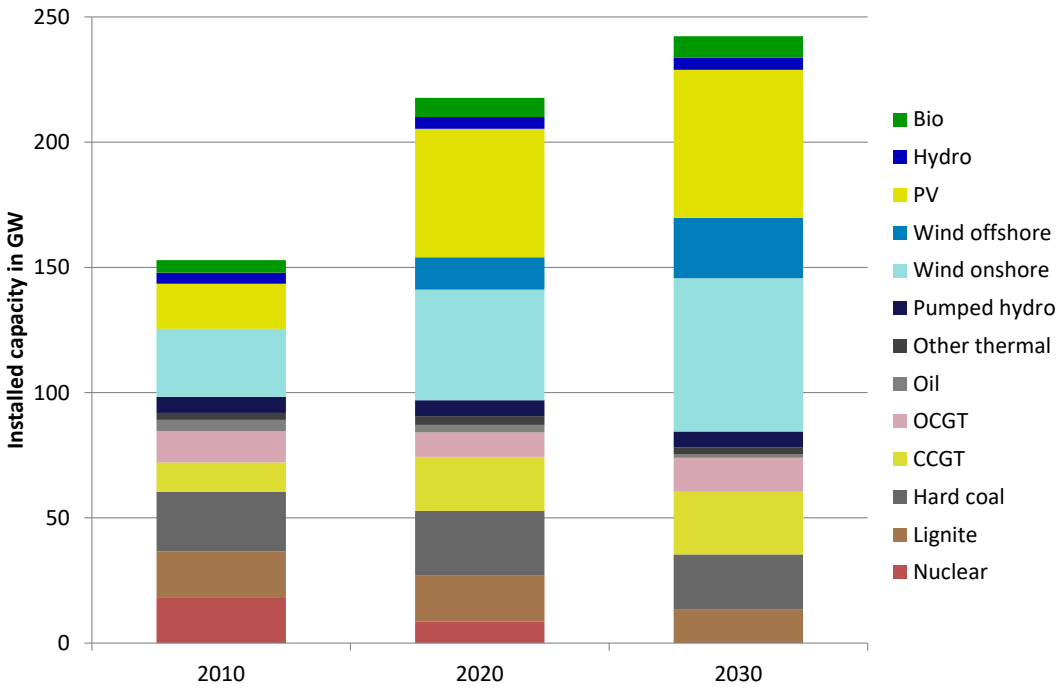


Figure 4.1.: Installed net generation capacities. Source: Own calculations based on 50Hertz et al. (2013b).

hydro storage capacity is assumed to stay constant. Overall, thermal generation capacities slightly decrease until 2030, whereas installed renewable capacities increase substantially (Figure 4.1). CCGT and OCGT refer to combined or open cycle gas turbines, respectively. We also include an expensive, but unlimited backstop peak generation technology in order to ensure solvability of the model even in cases of extreme vehicle charging patterns.

Hourly availability factors of onshore wind and PV are derived from publicly available feed-in data of the year 2010 provided by the German transmission system operators (TSOs). We project hourly maximum generation levels of these technologies for the years 2020 and 2030 by linearly scaling up to the generation capacities of the respective year.[19] Hourly power demand is assumed not to change compared to 2010 levels. We assume a total yearly net consumption of around 561 terawatt-hours (TWh), including grid losses, with a maximum hourly peak load of 91.9 gigawatt (GW). As regards other techno-economic parameters such as efficiency of thermal generators, start-up costs, and minimum off-times, we largely draw on Egerer et al. (2014).

All exogenous model parameters related to electric vehicles – except for the parameter $fastchargegoal$ – are provided by Kasten and Hacker (2014). The input

[19] Offshore wind feed-in data is available for selected projects in the North Sea only. We derive hourly availability factors from 2012 feed-in data provided by the transmission system operator TenneT.

Table 4.3.: Exogenous parameters related to electric vehicles.

	2020		2030	
	BAU	**EM$^+$**	**BAU**	**EM$^+$**
Number of vehicles (million)				
BEV	0.1	0.1	0.9	1
PHEV/REEV	0.3	0.4	2.9	3.7
Overall	0.4	0.5	3.7	4.8
Cumulative battery capacity (GWh)				
BEV	2.4	2.8	21.7	25.2
PHEV/REEV	3	3.9	27.6	35.9
Overall	5.4	6.7	49.2	61.1
Cumulative average hourly charging capacity (GW)				
BEV	0.3	0.3	2.9	3.1
PHEV/REEV	0.7	0.8	8.7	10.3
Overall	1	1.1	11.6	13.3

Source: Kasten and Hacker (2014).

data includes aggregate hourly power consumption and maximum charging profiles of 28 vehicle categories, of which 16 relate to BEV and 12 to PHEV/REEV. Vehicle categories differ with respect to both their battery capacity and their typical charging power. All vehicles may be charged with a net power of 10.45 kilowatt(kW) in some hours of the year, as they are assumed to be connected to (semi-)public fast-charging stations at least occasionally. Table 4.3 provides an overview of EV-related parameters. The cumulative battery capacity in the 2030 is in the same order of magnitude as the power storage capacity of existing German pumped hydro storage facilities. Table 4.3 also includes an indicative yearly average value of hourly recharging capacities, which reflects different hourly connectivities to charging stations and different charging power ratings.

4.4. Results

4.4.1. Charging of electric vehicles

The yearly power consumption of electric vehicles in the different scenarios is generally small compared to overall power demand (Table 4.4). In 2020, the EV fleet accounts for only around 0.1–0.2% of total power consumption. In 2030, EV-related power consumption gets more significant with up to 7.1 TWh in BAU and nearly 9.0 TWh in EM$^+$, which corresponds to around 1.3% of total power consumption, or 1.6%, respectively. In the user-driven charging modes, the values are generally slightly lower compared to cost-driven charging because the electric shares of PHEV/REEV are lower. These electric utility factors are around 55% in the 2020 scenarios, and between

Table 4.4.: Power consumption of electric vehicles.

EV scenario	Charging mode	Generation capacities		EV consumption (TWh) 2020	EV consumption (TWh) 2030	Share of total load (%) 2020	Share of total load (%) 2030
BAU	User-driven	Baseline		0.7	6.92	0.12	1.22
	Cost-driven			0.7	7.1	0.12	1.25
EM$^+$	User-driven	Baseline		0.88	8.59	0.16	1.51
	75% fast charge				8.9		1.56
	50% fast charge				8.95		1.57
	25% fast charge				8.95		1.57
	Cost-driven			0.88	8.95	0.16	1.57
	User-driven	RE$^+$	100% Wind		8.54		1.5
			50% Wind/PV		8.55		1.5
			100% PV		8.59		1.51
	Cost-driven		100% Wind		8.95		1.57
			50% Wind/PV		8.95		1.57
			100% PV		8.95		1.57

Source: Own calculations.

60% (user-driven) and 64% (cost-driven) in the 2030 scenarios. For comparison, Kelly et al. (2012) estimate a utility factor of around 67% based on data from 170,000 vehicles in the U.S. Weiller (2011) also determines utility factors for U.S. PHEVs between 50% and 70%, depending on the battery size and car usage.

While overall power consumption of the assumed EV fleets is relatively small, hourly charging loads vary significantly over time and sometimes become rather high. This is especially visible in the case of user-driven charging, where charging takes place without consideration of current power system conditions. Here, EVs are charged as fast as possible given the restrictions of the grid connection.[20] Figure 4.2 exemplarily shows the average charging power over 24 hours(h) for the 2030 EM$^+$ scenario for the two extreme charging cases as well as for the intermediate charging modes, in which at least 25%, 50%, or 75% of the vehicles' battery capacities have to be recharged as quickly as possible after the vehicles are connected to the grid. User-driven charging results, on average, in three distinct daily load peaks. These occur directly after typical driving activities. Almost no charging takes place at night, as EVs are fully charged several hours after the last evening trip. In contrast, the cost-driven charging mode allows charging EVs during hours of high PV availability, and shifting charging activities into the night, when other electricity demand is low.

[20] We do not consider possible restrictions related to bottlenecks in both the transmission and the distribution grids, which may pose barriers to both the fully user-driven and the fully cost-driven charging modes.

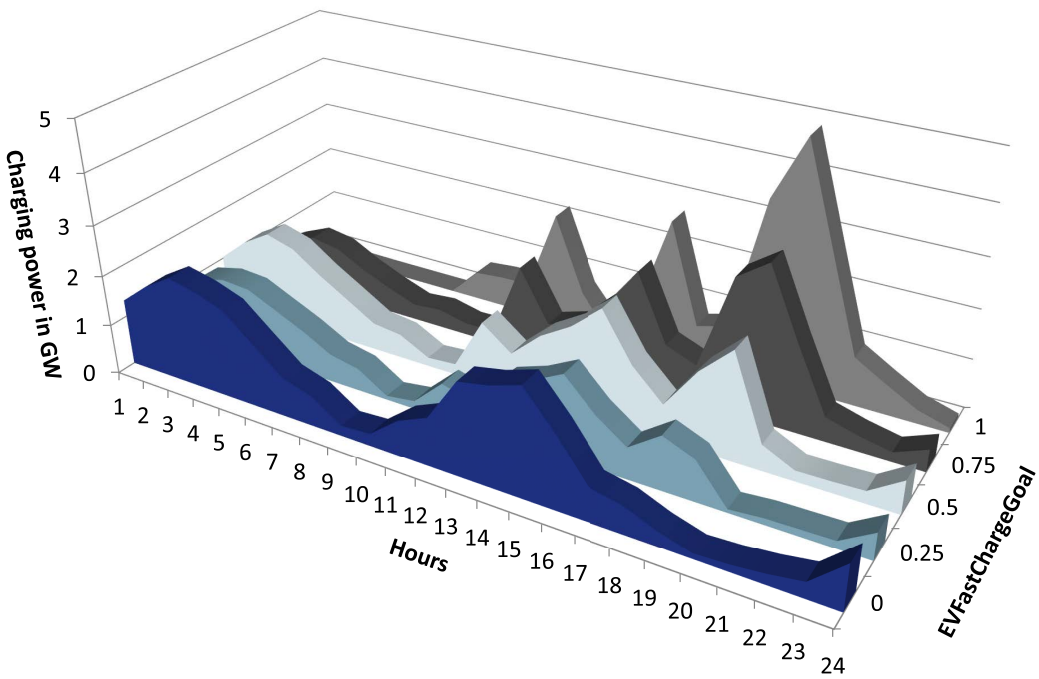


Figure 4.2.: Average EV charging power over 24 h (2030, EM$^+$). Source: Own calculations.

Overall, the average charging profile is much flatter in the cost-driven mode compared to the user-driven one.

From a power system perspective, average charging levels of electric vehicles are less relevant than the peak loads which EVs induce on the system. Figure 4.3 shows the electricity system's load duration curve without electric vehicles, i.e., all observed hourly loads in descending order (right axis). In addition, the sorted additional loads related to EVs for different charging modes are shown (left axis).[21]

Figure 4.3 shows that fully user- driven charging generally steepens the load duration curve of the system, as additional power is mainly required on the left-hand side. That is, user- driven charging increases the system load during hours in which demand is already high. On the very left-hand side, the peak load in the fully user- driven mode increases by around 3.6 GW, compared to only 1.5 GW in the purely cost-driven mode. In contrast, cost-driven charging largely occurs on the right-hand-side of the load duration curve, which implies a better utilization of generation capacities during off-peak hours. We again find a strong effect of even slightly deviating from the fully user-driven mode: reducing $fastchargegoal$ from 1 to 0.75 results in substantial smoothing of the residual load curve. If this parameter

[21] The figure shows the differences between sorted load duration curves with and without EVs for different charging modes. That is, the differences refer to load deviations between hours with the same position in the load duration curve, but not necessarily between the same hours, i.e., the index t will typically differ.

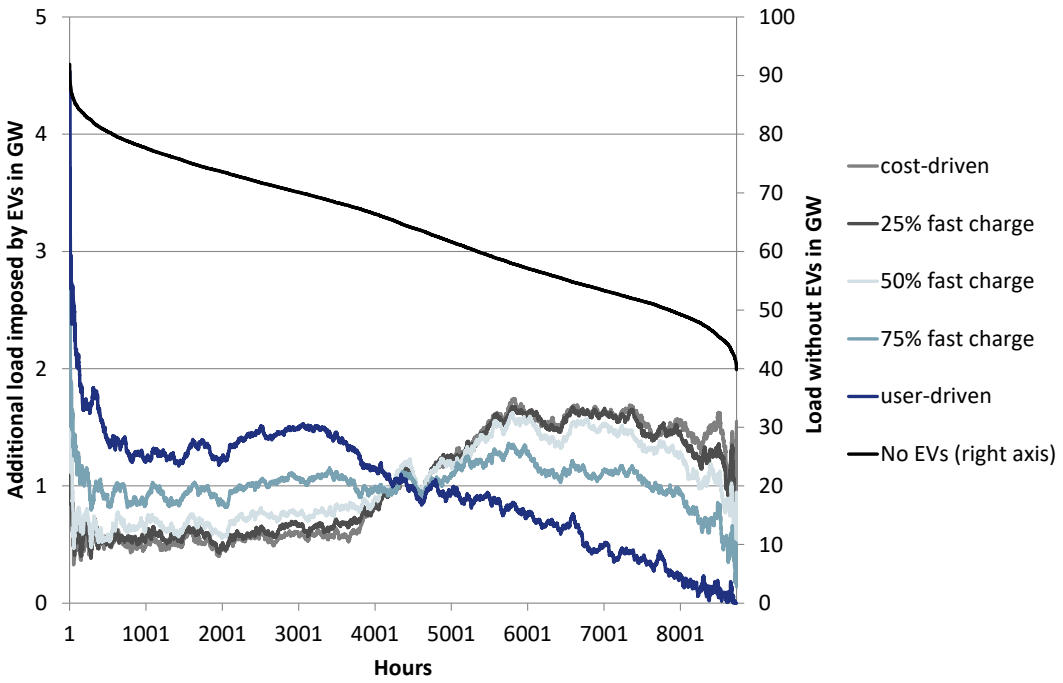


Figure 4.3.: Impacts of EVs on the load duration curve under different charging modes (2030, EM$^+$). Source: Own calculations.

is further reduced to 0.5, the load duration curve closely resembles the one of the fully cost-driven charging mode.

It should be noted that the backstop peak technology is required in the 2030 scenarios under fully user-driven charging in order to solve the model. That is, the generation capacities depicted in Figure 4.1 do not suffice to serve overall power demand during peak charging hours. The NEP generation capacities are exceeded by around 220 megawatt(MW) in the peak hour of the user-driven 2030 BAU scenario, and by around 360 MW in the respective EM$^+$ scenario. In other words, user-driven charging would raise severe concerns with respect to generation adequacy and may ultimately jeopardize the stability of the power system with the assumed EV fleets.

4.4.2. Power plant dispatch

The differences in hourly EV charging patterns discussed above go along with a changed dispatch of the power plant fleet.[22] While EV-related power requirements in the user-driven case mainly have to be provided during daytime, cost-driven charging allows, for example, utilizing idle generation capacities in off-peak hours.

[22] We only present dispatch results for the EM$^+$ scenarios of 2020 and 2030 as well as 2030 RE$^+$. The respective dispatch results in the BAU scenarios are very similar, but less pronounced.

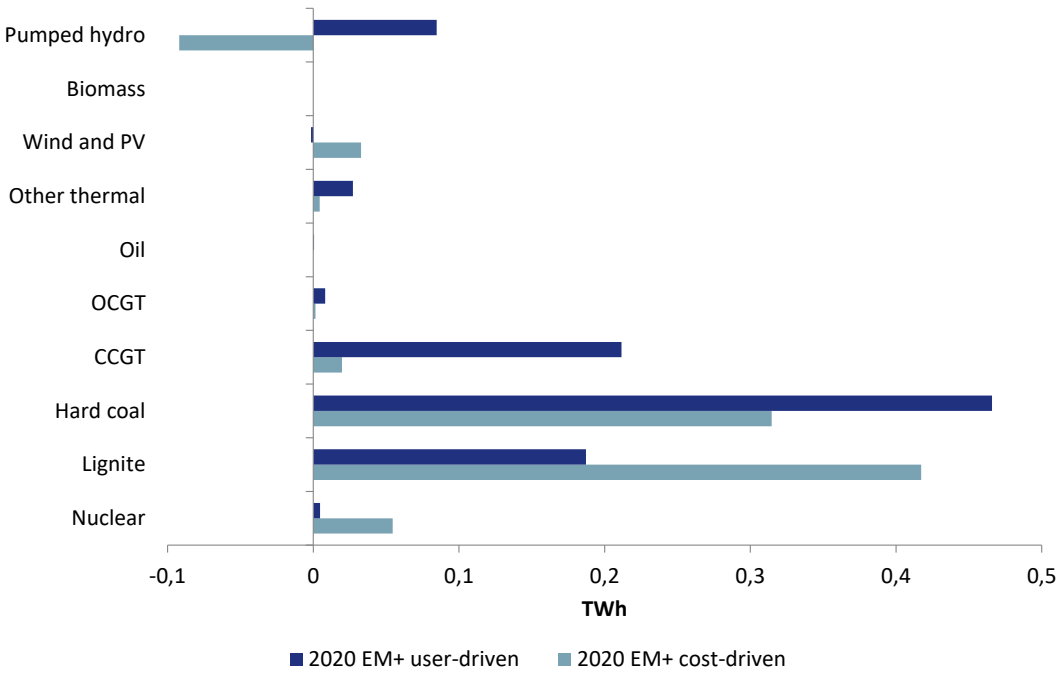


Figure 4.4.: Dispatch changes relative to scenario without EVs (2020, EM$^+$). Source: Own calculations.

Comparing dispatch in the 2020 EM$^+$ scenario to the one in the case without any electric vehicles in the same year, we find that the introduction of electric vehicles under cost-driven charging mostly increases the utilization of lignite plants, which have the lowest marginal costs of all thermal technologies (Figure 4.4).[23]

Generation from mid-load hard coal plants also increases substantially. These changes in dispatch are enabled by the charging mode, which allows shifting charging to off-peak hours in which lignite and hard-coal plants are under- utilized. Under user-driven charging, power generation from lignite cannot be increased that much, as charging occurs in periods in which these plants are largely producing at full capacity, anyway. Instead, generation from hard coal grows even more than in the cost-driven case. In addition, user-driven charging increases the utilization of – comparatively expensive – gas-fired plants, as these are the cheapest idle capacities in many recharging periods, e.g., during weekday evenings. The utilization of pumped hydro storage decreases slightly under cost-driven charging, as optimized charging of electric vehicles diminishes arbitrage opportunities of storage facilities. In contrast, storage use increases slightly under user-driven charging because of increased arbitrage opportunities between peak and off-peak hours.

[23]Figure B.1 in the Appendix B shows the dispatch results of the scenarios without EVs, against which the EV-related dispatch changes presented in Figs. 4.4–4.6 may be compared.

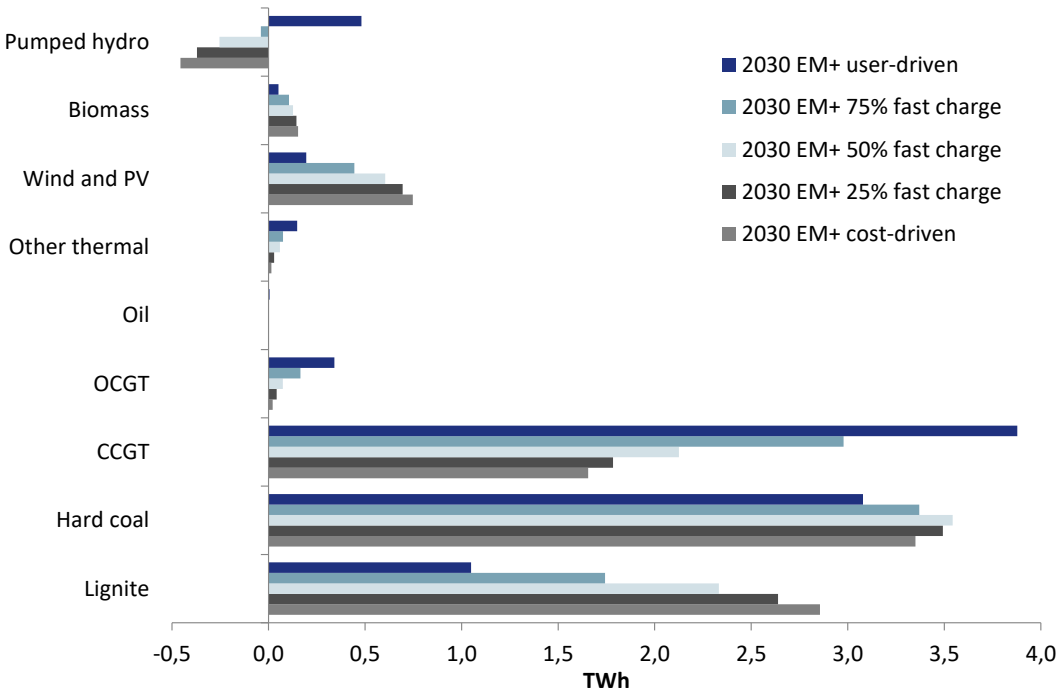


Figure 4.5.: Dispatch changes relative to scenario without EVs (2030, EM$^+$). Source: Own calculations.

Figure 4.5 shows respective changes in dispatch outcomes for the 2030 EM$^+$ scenario. Compared to 2020, the introduction of electric vehicles has a much stronger effect in 2030, as the overall number of electric vehicles is much higher. While the direction of dispatch changes is largely the same as in 2020, there is a slight shift from lignite to gas: under cost-driven charging, the relative increase in the utilization of lignite plants is less pronounced compared to 2020, whereas the utilization of combined cycle gas turbines (CCGTs) is higher. Under user-driven charging, this effect – which can be explained by an exogenous decrease of lignite plants and a corresponding increase of gas-fired generation capacities (cf. Figure 4.1) – is even more pronounced, such that most of the additional power generation comes from CCGT plants. Worth mentioning, the additional flexibility brought to the system by cost-driven charging also enables additional integration of energy from renewable sources. Pumped storage, which is another potential source of flexibility, is accordingly used less in the cost-driven case. It can also be seen that reducing the fast charging requirement from 100% to 75% strongly alters the dispatch into the direction of the cost-driven outcomes. Reducing the requirement to 50% entails largely the same dispatch as the fully cost- driven charging mode.

In the cases presented so far, we have assumed that the power plant fleets of the years 2020 or 2030 do not change between the cases with and without electric vehicles. While this assumption proves to be unproblematic with respect to overall generation

Table 4.5.: Additional generation capacities in RE$^+$ scenarios (in MW).

Charging mode	**100% Wind**	**100% PV**	**50% Wind/PV**	
			Wind	PV
User-driven	6,176	13,235	3,088	6,617
Cost-driven	6,438	13,795	3,219	6,897

Source: Own calculations.

capacities in the cost-driven charging mode, we are interested in how results change if the power plant fleet is adjusted to the introduction of electric mobility. While there are many thinkable changes to the generation portfolio,[24] we are particularly interested in cases in which the introduction of electric vehicles goes along with a corresponding increase in renewable energy generation. In fact, German policy makers have directly linked the introduction of electric vehicles to the utilization of renewable power (Bundesregierung, 2011). Yet results presented so far have shown that the additional energy used to charge EVs is mainly provided by conventional power plants, and particularly by emission-intensive lignite plants in the cost-driven charging mode.

In the 2030 RE$^+$ model runs, we add onshore wind and/or photovoltaics capacities to such an extent that their potential yearly feed-in exactly matches the amount of energy required to charge EVs. We distinguish three cases in which this power is generated either with 100% onshore wind, 100% PV, or fifty-fifty (Table 4.5).[25] The required PV capacities are much larger compared to onshore wind because of PV's lower average availability. In the cost-driven charging mode, capacities are slightly higher than in the user-driven mode, as the overall power consumption of PHEV and REEV is higher.

The outcomes of the RE$^+$ cases may be compared to the 2030 scenario without EVs and without additional renewables. This may be interpreted as if the deployment of EVs was strictly linked to an additional deployment of renewables, which would not have occurred without the introduction of electric mobility. Under user-driven charging, lignite plants are used less, while gas-fired plants and pumped hydro stations are increasingly utilized. This can be explained by increasing flexibility requirements in the power system induced by both additional (inflexible) EVs and fluctuating renewables. In contrast, power generation from lignite increases under cost-driven

[24] For example, additional open cycle gas turbines may be beneficial under user-driven charging, while additional base- load plants may constitute a least-cost option under cost-driven charging. Note that we do not determine cost-minimal generation capacity expansion endogenously, as we use a dispatch model in which generation capacities enter as exogenous parameters.

[25] Additional deployment of renewables involves additional capital and fixed costs. These are not considered here. Onshore wind and PV as well incur different capital costs. Yet we do not aim to determine a cost-minimizing portfolio; rather, we are interested in the effects of different technology choices on dispatch outcomes.

charging, whereas gas-fired plants and pumped hydro facilities are used less. This is because system-optimized EV charging brings enough flexibility to the power system to replace pumped hydro and gas-fired plants and at the same time increase generation from rather inflexible lignite plants.

Finally, we provide further details on the integration of fluctuating renewables. It has often been argued that future electric vehicle fleets may help to foster the system integration of fluctuating renewables (compare Hota et al. (2014)). Our model results show that the potential of EVs to reduce renewable curtailment is rather low under user-driven charging, but sizeable in case of cost-driven charging (Figure 4.6).[26] In 2020, very little curtailment takes place, and the effect of EVs on curtailment is accordingly negligible. In the 2030 EM^+ scenario, about 1.3 TWh of renewable energy cannot be used in the case without EVs, corresponding to 0.65% of the yearly power generation potential of onshore wind, offshore wind and PV. User-driven EV charging decreases this value to about 1.1 TWh (0.55%), while only 0.6 TWh of renewables have to be curtailed under cost-driven charging (0.29%). Accordingly, optimized EV charging allows slightly increasing the overall utilization of renewables. Curtailment is generally higher in the RE^+ scenarios. Among the three different portfolios of additional renewable generators, the one with 100% PV has the lowest curtailment levels (1.9 TWh or 0.89% in the case without electric vehicles), while curtailment is highest in the one with 100% onshore wind (2.3 TWh or 1.07%). Cost-driven charging results in much lower levels of renewable curtailment compared to user-driven charging.

4.4.3. CO_2 emissions

We have shown that EVs may increase the utilization of base-load capacities as well as fluctuating renewables.[27] While the first tends to increase CO_2 emissions, the latter has an opposite effect. Both effects overlap. The net effect on emissions is shown in Figure 4.7, which features specific emissions of both overall power consumption and EV charging electricity. The latter are calculated as the difference of overall power plants' CO_2 emissions between the respective case and the scenario without electric vehicles, related to the overall power consumption of EVs.[28]

[26] In addition, electric vehicles may indirectly foster the system integration of renewable power generators by providing reserves and other ancillary services energies, which are increasingly required in case of growing shares of fluctuating renewables.

[27] It should be noted that the dispatch model not only considers CO_2 emissions related to the actual generation of power, but also to the start-up of thermal power plants.

[28] The analysis accordingly focuses on direct CO_2 emissions from the operation of power plants, and is not based on a full life-cycle assessment of electric vehicles.

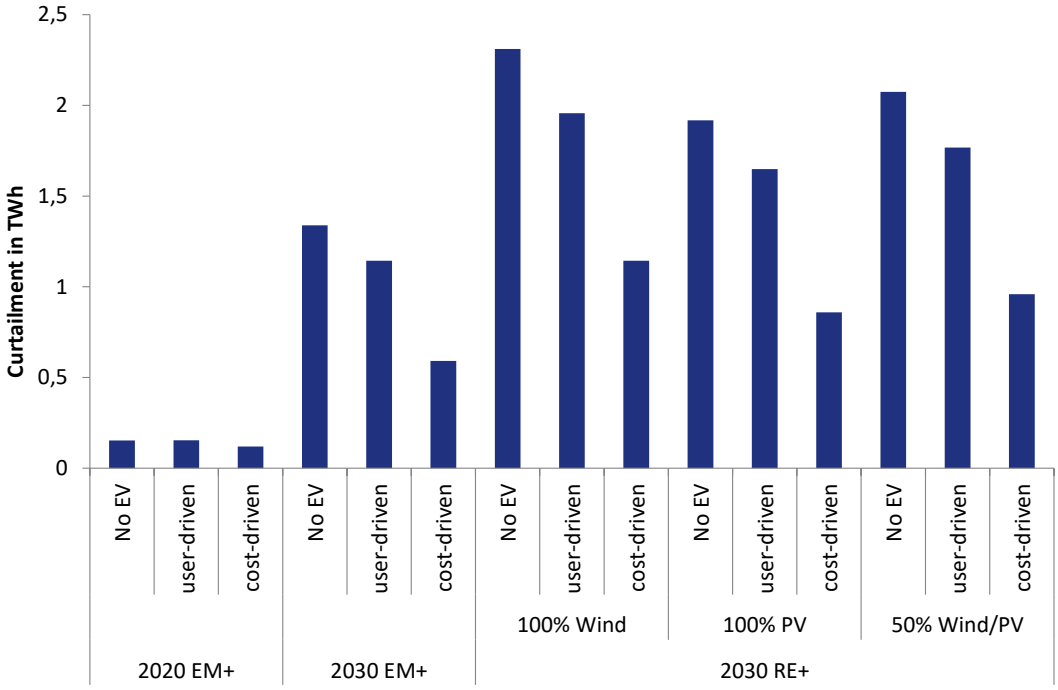


Figure 4.6.: Renewable curtailment. Source: Own calculations.

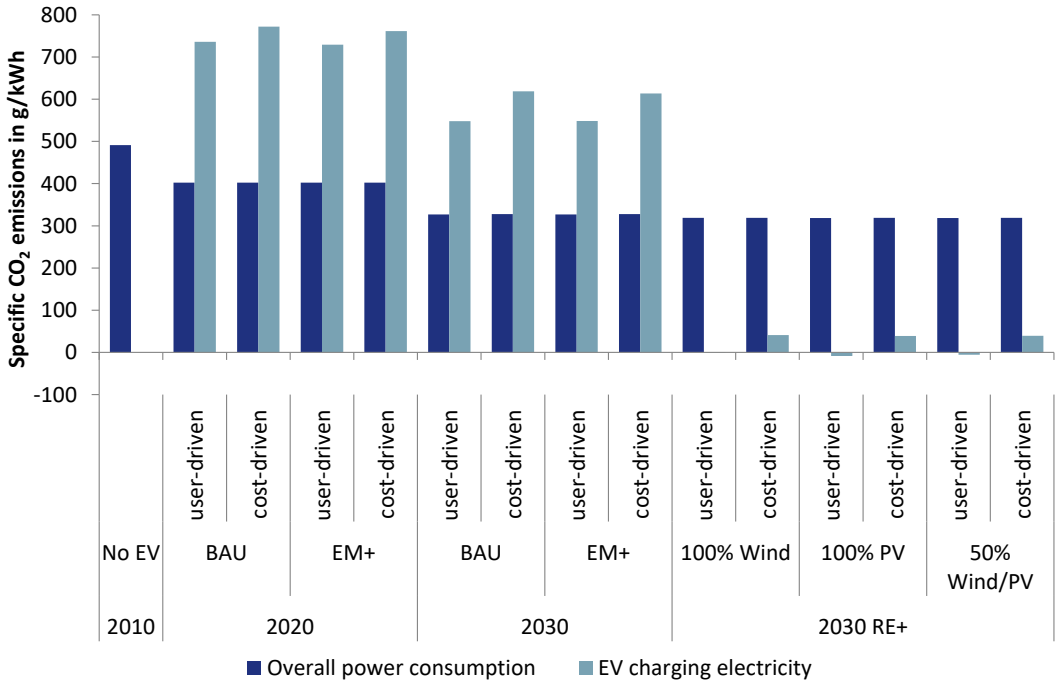


Figure 4.7.: Specific CO_2 emissions. Source: Own calculations.

Due to ongoing deployment of renewable generators, specific CO_2 emissions of the overall power consumption decrease from around 490 g/kWh in 2010 [29] to around 400 g/kWh in 2020, to less than 330 g/kWh in the 2030 BAU and EM^+scenarios, and to around 320 g/kWh in the 2030 RE^+ scenarios. In the BAU and EM^+ scenarios of both 2020 and 2030, specific emissions of the EV charging electricity are substantially larger than average specific emissions, as it is largely generated from emission-intensive technologies like lignite and hard-coal. The improvements in renewable integration related to EVs are by far outweighed by the increases in power generation from conventional plants. Only in the 2030 RE^+ scenarios, in which the introduction of electric vehicles goes along with additional renewable generation capacities, specific emissions of the charging electricity are well below the system-wide average. Note that we compare the RE^+ scenarios to the same reference scenario as the 2030 EM^+ runs, i.e., a 2030 scenario without EVs and without additional renewable generation capacities. The system-wide emission effect of additional renewables is thus fully attributed to electric vehicles, even if EVs are not fully charged with renewable power during the actual hours of charging.

Among the two different charging strategies, the cost-driven mode always leads to higher emissions compared to the user-driven mode, as the first allows for switching some charging activities into hours in which lignite plants are under-utilized, whereas the latter forces charging to happen mostly in hours in which lignite and hard-coal plants are already fully utilized. Interestingly, this outcome contrast the findings of Göransson et al. (2010), which show for a Danish case study that user-driven charging increases system-wide CO_2 emissions, whereas cost- driven charging decreases emissions. These differences can be explained by different power plant fleets in the two case studies: The Danish system has low capacities of emission-intensive generators and very high shares of wind, with accordingly high levels of curtailment. In contrast, our German application features much higher capacities of emission-intensive generators as well as lower shares of wind power. Accordingly, the increase in power system flexibility related to cost-driven EV charging is predominantly used for reducing renewable curtailment in the Danish case and for increasing the utilization of lignite and hard-coal plants in Germany.

4.5. Discussion of limitations

We briefly discuss some of the model limitations and their likely impacts on results. First, the future development of exogenous model parameters is generally uncertain.

[29] According to model results. The officially reported CO_2 intensity for 2010 is slightly higher. Yet in this context, only the relation between different scenarios is relevant and not so much absolute emission levels.

This refers, in particular, to the future power plant fleet. We have thus decided to largely draw on the assumptions of a well-established scenario (50Hertz et al., 2013b). In this way, meaningful comparisons to other studies which lean on the same scenario are possible. On the downside, the power plant fleet is necessarily not optimized for the integration of electric vehicles. This shortcoming, however, should not have a large impact on results, as overall power consumption of electric vehicles is very small compared to power demand at large.

In Appendix B.3, we provide the dispatch outcomes for additional sensitivity analyses that include alternative assumptions on the power plant fleet, higher CO_2 prices, and cross-border exchange. We find that general dispatch results hardly change in most sensitivity runs, except for the case in which CO_2 prices are assumed to double, as this reverses the merit order of gas- and coal-fired plants.

While using projections of future power generation from fluctuating renewables, drawing on historic feed-in data of other years than 2010 may lead to slightly different dispatch results. What is more, calculating availability factors from feed-in time series neglects potential smoothing effects related to future changes in generator design or changes in the geographical distribution. This may result in exaggerated assessments of both fluctuation and surplus generation, as discussed by Schill (2014).

Next, our dispatch model assumes perfectly uncongested transmission and distribution networks. This assumption appears to be reasonable with respect to the transmission grid, as the NEP foresees perfect network expansion. Yet on the distribution level, a massive deployment of electric vehicles may lead to local congestion. Such effects can hardly be considered in a power system model. It is reasonable to assume that congestion in distribution grids may put additional constraints on the charging patterns of electric vehicles. While this effect should in general be relevant for both the user-driven and the cost-driven charging mode, distribution grid bottlenecks may be particularly significant for the user-driven mode, as charging is carried out largely in peak-load periods in which the distribution grid is already heavily used.

In addition, we abstract from interactions with neighboring countries. In the context of existing interconnection and plans for further European market integration, this assumption appears to be rather strong. Yet considering power exchange with neighboring countries would require a much larger model with detailed representations of these countries' power plant fleets, and according parameters on future power system and EV developments in these countries. Solving a large European unit commitment model for a full year and various scenarios would be very challenging. By treating the German power system as an island, we may generally overestimate the flexibility impacts of electric vehicles such as additional integration of lignite and renewables, as well as peak capacity problems in the user-driven mode, as exchange with neighboring countries would entail additional flexibility which may mitigate both

peak and off-peak load situations. Our results may thus be interpreted as an upper boundary for the flexibility impacts of EVs on the German power system. In fact, the effects of EVs on lignite-fired power generation are mildly mitigated compared to the EM^+ runs in a sensitivity analysis in which we fix the hourly pattern of net power exchange with neighboring countries to 2010 levels.

Next, we only consider G2V power flows and abstract from V2G flows. This assumption may be justified for the wholesale market, as wholesale price differences likely do not suffice to make V2G economically viable with respect to battery degradation costs (Loisel et al., 2014; Schill, 2011). The provision of reserves and other ancillary services by V2G, however, appears to be more promising (Andersson et al., 2010; Lopes et al., 2011; Sioshansi and Denholm, 2010). We also abstract from the provision of reserves, which may result in underestimated levels of conventional generation, and accordingly underestimated renewable curtailment.

Finally, it should be noted that cost-driven charging generally reduces the utility of vehicle owners compared to the user-driven mode. Under cost-driven charging, users would have to make regular forecasts about when they use their cars again, and how long the next trips will be. In the real-world, this may pose a considerable barrier to the adoption of a purely cost-driven charging mode. On the other hand, charging costs are lower in the cost-driven mode, as the EV owner – or the retailer, or some other service provider, respectively – can make use of lower wholesale prices. Further savings should be possible if not only the wholesale market, but also reserve markets and other ancillary services could be accessed, probably in combination with V2G applications. Yet the feasibility of such strategies as well as the quantification of utility losses and cost savings remain questions for future research. In any case, a partly cost-driven charging mode as modeled here (for example, with $fastchargegoal$ of 50%), may provide a feasible middle ground between users' preferences and power system requirements.

4.6. Conclusions

We analyze the integration of future fleets of electric vehicles into the German power system for various scenarios of 2020 and 2030. We use a numerical dispatch model with a unit commitment formulation which minimizes overall dispatch costs over a full year to study the effects of different charging modes on the load curve, dispatch, costs, and emission. By applying a novel model formulation, we are able not only to simulate extreme charging modes, but also more realistic intermediate ones.

Based on our findings we suggest several policy-relevant conclusions. First, the overall energy requirements of electric vehicles should not be of concern to policy makers for the time being, whereas their impact on peak loads should be. Not only

with respect to costs, but also to system security, cost-driven charging is clearly preferably to the user-driven mode. Because of generation adequacy concerns, user-driven charging may have to be restricted, at the latest if the vehicle fleet gets as large as in our 2030 scenarios, unless high charging tariffs render user-driven charging unattractive, anyway.

Second, policy makers should be aware that cost-optimized charging not only increases the utilization of renewable energy, but also of low-cost emission- intensive plants. If the introduction of electric mobility is linked to the use of renewable energy, as repeatedly stated by the German government, it has to be made sure that a corresponding amount of renewables is added to the system. With respect to CO_2 emissions, an additional expansion of renewables is particularly important as long as substantial – and increasingly under-utilized – capacities of emission-intensive generation technologies are still present in the system. From a system perspective it does not matter if these additional renewables are actually fully utilized by EVs exactly during the respective hours of charging; rather, the net balance of the combined introduction of electric mobility and renewables compared to a baseline without EVs and without additional renewables is relevant.

Third, cost-driven charging, which resembles market-driven or profit- optimizing charging in a perfectly competitive market, can only lead to emission-optimal outcomes if emission externalities are correctly priced – as, for example, in a sensitivity analysis that assumes double CO_2 prices. Otherwise, cost-driven charging may lead to above-average specific emissions, and even to higher emissions compared to the user-driven mode. Accordingly, policy makers should make sure that CO_2 emissions are adequately priced. Otherwise, some kind of emission-oriented charging strategy would have to be applied, which is possible in theory (cf. Sioshansi and Miller 2011), but very unlikely to be implemented in practice. Fourth, controlled charging of future electric vehicle fleets interacts with other potential sources of flexibility in the system. Our analysis indicates that the utilization of pumped hydro storage substantially decreases in the cost-driven mode compared to user-driven charging. The same may hold for other storage technologies and load shifting. Accordingly, the viability of such flexibility options depends on the size of the future EV fleet, as well as on the charging mode.

Finally, we conclude that even a slight relaxation of fully user-driven charging leads to much smoother charging profiles. That is, undesirable EV impacts on the system peak load could be substantially reduced if vehicle owners would agree to have not the full battery capacity charged as quickly as possible after connecting to the grid, but only a (possibly large) fraction of it. We show that a large part of the system benefits generated by fully cost-driven charging could already be realized with a fast charging requirement of around 50% or even 75%. This suggests that EV

user preferences – such as not giving control over charging away completely, or being able to make previously unplanned trips – and power system requirements could be reconciled by a charging strategy which makes sure that not the full battery capacity is charged as soon as possible.

Part II

Network aspects

Chapter 5

The role of electricity transmission infrastructure in Germany

This chapter is a single author publication based on Chapter 7 in the book "Energiewende – A Mid-Term Perspective on Electricity Sector Reform in Germany" by von Hirschhausen et al. (under review).

5.1. Introduction

In addition to the core objectives of the energiewende analyzed in Chapter 1, the infrastructure required to assure a reliable, clean, and economic electricity system is among the crucial conditions that have to be established for the energiewende to succeed. In this context, the electricity transmission infrastructure is a particularly important ingredient of the energiewende given the changing geographic distribution of electricity supply. Electricity transmission is a more controversial issue and also a stronger focus of attention because it involves important trade-offs between ambitious expansion projects by transmission system operators, important fuel choices overseen by regulators (e.g., decisions not to favor coal electrification through network extension), and the public debate about the appropriate siting of transmission corridors.

This chapter summarizes issues surrounding electricity transmission in the context of the energiewende. This chapter's hypothesis is that even though infrastructure is an important ingredient of the energiewende, its importance has been exaggerated in the policy debate and in the public debate as well. Often hailed as a "critical factor" in the energiewende – and sometimes as the final nail in its coffin – transmission infrastructure has not been a demonstrable obstacle to the energiewende thus far, thanks to the highly developed network inherited from the "old system" and its continuous improvement over the last decade. Even in the medium term – that is, into the 2020s – no serious constraints are to be expected, provided that the transmission system operators (TSOs) and regulatory agencies stick to the path of transmission expansion that has proven reliable so far.[30]

The next Section 5.2 describes network planning and development from its inception in the 2000s until today. Over this period, a new method of transmission planning has been implemented, creating more transparency for transmission policies, which had not been open to public scrutiny under the old system. Two possible explanations for the current situation in transmission expansion are also discussed. One is an algorithm created to identify expansion needs based on the assumption of a "copper plate" that by design ignores potential constraints in the establishment of the dispatch merit order.[31] The other is the high equity remuneration of TSOs (9.05 % or 6.91 %, see BNetzA, 2016b), incentivizing these companies to engage in high levels of investment. Section 5.3 then traces a decade of network development in Germany. As is discussed in detail, rates of transmission investment remain consistent over the years, and important connections, such as links between the former GDR and West Germany,

[30] This chapter does not consider electricity distribution infrastruture.

[31] In 2015, the possibility of 3% curtailment of renewable electricity feed-in was introduced into the grid planning process, which reduced the need for investments that are needed only a very few hours per year to accommodate both high wind and photovoltaic (PV) feed-in.

were completed. Section 5.4 summarizes results of a study on the effects of price zones in Germany, confirming the overall level of network congestion and suggesting that there is no need to split the German electricity market into zones. Section 5.5 discusses the current debate of introducing multiple price zones in Germany. Section 5.6 then discusses an interesting recent development: the explicit integration of carbon dioxide (CO_2) constraints into network planning. Section 5.7 concludes.

5.2. Transmission planning and incentives

5.2.1. Network planning before the energiewende

Electricity transmission, that is, long-distance transport of electricity at voltage levels of 200 kV and above, has been a major point of discussion in the energiewende and has received extensive attention from technical professionals, policy makers, and economic analysts. Even though electricity distribution is financially more important (with about five times the level of average annual investments), transmission is considered particularly challenging because of the changing structure of electricity generation, away from centralized conventional sources towards more decentralized renewable sources. In this context, a general belief prevailed in the 2000s that a major shift in grid architecture might occur, not only in Germany but also across Europe, towards the diffusion of "Supergrids," European-wide high-voltage corridors ("Stromautobahnen") that were expected to accompany the low-carbon energy transformation at the European level.

Before the advent of the energiewende, investments were made into the development of electricity transmission infrastructure with the intention of a congestion-free connection between mostly fossil and nuclear generators and industrial as well as household consumers. Transmission planning was a technical exercise, and a congestion-free infrastructure was considered to be normal; the costs of maintaining a "copper plate" were passed on to the electricity prices. Within the eight (later: four) vertically integrated energy companies, transmission was carried out alongside generation and sales. The transmission operators coordinated their activities somewhat in the "German Network Association" Deutsche Verbundgesellschaft (DVG), see for a historical overview Boll (1969).

Vertical unbundling, first introduced with the European Electricity Directive of 1996 (EC, 1996) and reinforced by the Acceleration Directive 2003/54/EC (EC, 2003b), along with an increasingly heated policy debate, increased pressure to modernize the institutional setting for transmission planning, which had proven to be intransparent and not open to either public or administrative oversight.

The first network planning exercise that involved some public consultation was coordinated by the German Energy Agency (dena, deutsche energieagentur), but the monopoly of data and network calculations remained with the TSOs (a situation that prevails to this day). The dena I network study (dena, 2005) concluded that 850 km of new-built lines and 392 km of line upgrades were needed by 2015. To accelerate network development, the "law on developing electricity transmission infrastructure" of 2009 (*Energieleitungsausbaugesetz,* EnLAG) was passed covering 24 projects that were considered particularly important, surpassing dena's suggestion, totaling 1,855 km in length.[32] For four of these lines, the law foresaw the possibility of laying some sections underground (Ganderkessee to Wehrendorf, Lauchstädt to Redwitz, Diele to Niederrhein, and Wahle to Mecklar). In the context of the Energy Concept 2010 and the first coordinated effort to create a European-wide Ten-Year Network Development Plan (TYNDP) (ENTSO-E, 2010), the dena I network study (dena, 2005) was followed by the dena II network study (dena, 2010), once again conducted by the four TSOs with the participation of two academic reviewers. The results suggested the need for upgrading and new builds above historical values partially driven by renewable in-feed in the grid: with 1,500-3,600 km of newly built lines and up to 5,700 km of upgrades by 2020. A critical analysis of the dena II network study by von Hirschhausen et al. (2010) pointed out the discrepancy between the results and a reasonable economic level of network extensions, as well as the TSO's incentives to overinvest (high rate of return, no congestion clause, etc.).

5.2.2. A renewed institutional framework for network planning

After the two dena network studies, the responsibility for network planning was shifted to the electricity sector regulator, the Federal Network Agency (BNetzA, Bundesnetzagentur). Following the mechanisms of structured network planning defined at the European level, prescribed by the third directive on the internal European Electricity Market,[33] transmission planning was completely reorganized by the new German Energy Law (*Energiewirtschaftsgesetz, EnWG*) of 2011.[34] In

[32] EnLAG (2009). *Gesetz zum Ausbau von Energieleitungen (Energieleitungsausbaugesetz – EnLAG).* URL: `https://www.gesetze-im-internet.de/bundesrecht/enlag/gesamt.pdf` (visited on September 15, 2016).

[33] EC (2009c). *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.* URL: `http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF` (visited on November 21, 2012).

[34] The German Energy Law of 2005 (BGBl 2005, Part I, p. 1970 `http://www.bgbl.de/xaver/bgbl/start.xav?startbk=Bundesanzeiger_BGBl&jumpTo=bgbl105s1970.pdf`), which implemented the Directive 2003/54/EC (EC, 2003b), was adapted in the Gesetz zur Neuregelung energiewirtschaftsrechtlicher Vorschriften (BGBl 2011, Part I, p. 1554 `http://www.bgbl.de/xaver/`

§12 EnWG, the new law prescribed a more open and interactive process, organized and controlled by the regulator, that included a series of public consultations and ended with a law passed by parliament. The TSOs were given the task of setting up a 10-year and 20-year network development plan for measures considered "necessary and urgent" (*vordringlicher Bedarf*):

- In a first step, the TSOs are asked to develop a scenario framework (*Szenariorahmen*), including three scenarios for the energy mix for the next two decades. There are essentially three scenarios for a time frame of ten years (called A, B, and C), with Scenario B updated to cover 20 years as well. These scenarios also contain assumptions on electricity demand, fuel prices, etc. Once this scenario framework is handed over to the regulator (BNetzA), it undergoes public consultation, and is then approved, possibly with amendments by the regulator.

- The TSOs then use the scenario framework to develop a long-term grid development plan (NEP, Netzentwicklungsplan), which is first consulted on publicly, then handed over to the regulator, who then undertakes a second consultation.

- The regulator has to approve, or reject, the individual lines that are proposed; in parallel, the regulator carries out an environmental assessment (*Umweltprüfung*).

- Finally, the approved network development plan is handed over to both chambers of parliament, the lower chamber (*Bundestag*) and the representatives of the 16 federal states (*Bundesrat*). Once approved by both chambers, it is published as the Federal Requirements Plan Law (*Bundesbedarfsplangesetz*).

Parallel to this new provision in the energy law, parliament also passed a law in 2011 that streamlined administrative responsibility within the regulatory agency, the BNetzA: the "transmission network development acceleration law" (*Netzausbaubeschleunigungsgesetz Übertragungsnetz*, NABEG) handed over responsibility for tracing the individual routes (*Bundesbedarfsplanung*) to the national regulator, as well as the decision-making process on the (local) siting of the corridors (*Planfeststellungsverfahren*). By concentrating activities at the national level that had previously been carried out by the 16 federal states individually, the some of the overarching objectives were envisaged to be incorporated into the procedure and

bgbl/start.xav?startbk=Bundesanzeiger_BGBl&jumpTo=bgbl111041.pdf) implementing the directive 2009/72/EC (see previous footnote). Since 2011, the planning process has been adapted, especially regarding the frequency of the planning procedures, see BGBl 2015, Part I, p. 2200 http://www.bgbl.de/xaver/bgbl/start.xav?startbk=Bundesanzeiger_BGBl&jumpTo=bgbl115s2194.pdf.

the implementation of the network development plan should be streamlined and accelerated.

The new procedure was applied for the first time in the network development exercise "NEP 2013," started in 2011. It has raised both public awareness and the participation of a broad range of stakeholders. Following a full cycle of this procedure, the first Federal Requirements Plan Law was adopted and put into effect in 2013. Since then, the process of scenario framework, network planning, and consultation has been carried out annually with only small changes regarding pilot projects for underground alternating current (AC) cables in 2014 and a larger iteration in 2015.

5.2.3. Remaining inefficiencies and investment incentives

Methodology guarantees congestion-free electricity feed-in

It is always better to have slight overinvestment in infrastructures than to have too little investment. In addition, the procedure of transmission investments, including regulation and oversight, should be as simple as possible to avoid "sophistication and complexity in network planning" (Olmos and Pérez-Arriaga, 2009, p. 5286). However, while the new procedure of network planning was a step in the right direction, it had two major drawbacks: first, while some underlying assumptions were stated explicitly in the scenario framework, the monopoly power of the TSOs in setting up the network development plan was maintained. And second, the modified institutional framework of transmission planning did not significantly change the incentives for network development, leading to a situation where congestion-less electricity transmission has remained the point of reference, pushing TSOs toward ambitious expansion plans (for details, see Weber et al., 2013).

A point of criticism of the procedure is the market design used in the NEP development, as it adheres too closely the "old world" market design, which takes the geographical distribution of generation capacities as given, so that neither constraints on feeding in electricity nor the costs of network expansion are taken into account, thus leading to a network, corresponding more or less to a "copper plate."[35] In fact, the first step of the procedure determines an "optimal market-based power plant dispatch" according to the merit order principle (with renewables benefiting from priority feed-in). The second step determines the resulting network expansion needs given the pre-determined dispatch from step one. Any power producer (fossil, nuclear, or renewable) has the right to sell their electricity (once in the merit order), independently of their location in the network.

[35]Some of these points are laid out in detail in Jarass and Obermair (2012).

The disregard of the geographical component led to siting of coal plants in Northern Germany, where access to coal is less expensive, whereas the capacity requirements are tend to be located in the South. As a result, the methodology must accommodate the parallel feeding-in of conventional and renewable electricity, leading to a network where especially the North-South corridors would have to be sized to fit situations of strong wind and full operation of hard coal and lignite power, a situation which tends to work against the climate objectives of the energiewende (see below).

The arguments in favor of an integrated network planning algorithm seem obvious, particularly in light of international experience in countries like the UK or in the US, with its restructured systems.[36] Yet these experiences have not been taken into account in the network planning carried out as part of the German energiewende. It is unclear whether this strategy was chosen deliberately, perhaps to prevent major network congestion, following the example of Alberta, Canada, where the network operator is obliged to avoid congestion.[37] However, if this was indeed the far-sighted strategy, it should have been stated clearly by the regulator at the outset.

Equity remuneration

Another driver of the high levels of investment is the regulatory regime under which the TSOs operate. Eyre and Pollitt (2016) provide an extensive survey of regulatory regimes and the effects of incentives on the transmission planning process. Germany was definitely a latecomer in this process: After a long period of cost-based remuneration of network companies in the "old system," what is known as "incentive regulation" was introduced in 2005. These "incentives" proved, however, to be quite favorable to the TSOs: in addition to a large share of the costs that were exempted from benchmarking because they were declared "not modifiable" by the TSO, all new investment projects received a generous return on equity of 9.05 %;[38] at an average rate of inflation of 0-2%, this corresponds to a real rate of return of 6-7%, for an almost risk-free activity.[39] Comparing this to the average return of a risk-free asset

[36] For a survey and another concrete application see Kemfert et al. (2016).

[37] See The Brattle Group (2007, p. 32).

[38] See BNetzA (2011). *BK4-11-304 Beschluss hinsichtlich der Festlegung von Eigenkapitalzinssätzen für Betreiber von Elektrizitäts- und Gasversorgungsnetzen für die zweite Regulierungsperiode in der Anreizregulierung.* URL: `http://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1BK-Geschaeftszeichen-Datenbank/BK4-GZ/2011/2011_0001bis0999/2011_300bis399/BK4-11-304_BKV/BK4-11-304_Festlegungsbeschluss_Zinssatz.pdf?__blob=publicationFile&v=1` (visited on September 14, 2016). Even a downward adjustment to "only" a return on equity to 6.91 % (see BNetzA, 2016b), suggested for the next regulatory period, would still be significantly above the risk-free return.

[39] Some minor provisions in the legislation reduced the real rate of return somewhat, such as the initial two-year delay between expenditures and payback through regulated network fees, see for details Beckers et al. (2014).

(in the range of 1-3%) reveals the high incentives for TSOs to invest heavily in new transmission infrastructure.

For grid planning, the so-called NOVA principle[40] should be used to guide the network policy: It implies that the first priority is to optimize the use of the existing grid; second, to upgrade existing lines, and only third, to build new lines. Some technologies exist to increase the capacity of the lines, for instance, using high-temperature conductors in the existing grid, which increases line capacity significantly.[41] Also, the active monitoring of existing lines (*Leiterseilmonitoring*) has the potential to increase capacity in times of potential congestion, i.e., cold winter days, by indicating a surplus capacity of certain lines (due to the low temperatures). Even though the overall potential of capacity upgrades are estimated in the range of 20-30%, this instrument was not pursued very actively by the TSOs (see Jarass and Obermair, 2012; Jarass and Jarass, 2016).

5.3. Overview of network development plans

5.3.1. Projected future network development

The TSOs in Germany responded quite rationally to the incentives and the mandate of a congestion-free grid: they planned substantial investments. It is difficult to quantify a degree of overinvestment as there is a very fine line between overinvesting and "staying on the safe side." However, the empirical observation of the network transmission plans drawn up by the TSOs support the hypothesis.

This holds for both periods, the period of almost unregulated transmission planning in the two first dena-network studies, i.e., before 2011, and the subsequent period of more formalized network development procedures initiated with the energy law of 2011 (EnWG, 2011). Network development plans developed in the second period envisaged an increase in planned new builds and line upgrades relative to the average of 50–100 km of high-voltage transmission lines built over the previous decade, and thus overstated the grid development need.

Table 5.1 shows the aggregate figures for network expansion and network upgrades as presented in the subsequent network planning exercises, beginning with the dena I network study (dena, 2005) and running up to the network planning exercise in 2015 (the NEP 2024 is the latest approved version). Compared to about 60–100 km actually built per year, the plans overestimate the grid investment.

[40] NOVA, in German, stands for *N*etz*O*ptimierung, - *V*erstärkung und –*A*usbau (network optimization, strengthening, and expansion).

[41] The pilot project of installing high-temperature conductors in 2013 was successful: the capacity of the 380 kV line between Remptendorf and Redwitz (East Germany to Bavaria) was increased by 400 MW or approx. 25%.

Table 5.1.: Aggregate transmission network expansion plans over time (2005 – 2016)

Planning document	**Network newbuilt**	**Network upgrades**
dena I network study (dena, 2005, p. 126)	851 km up to 2015	392 km up to 2015
dena II network study (dena, 2010, p. 364)	1,500 km up to 2015, as well as 1,700 km to 3,600 km from 2015 to 2020 depending on scenario	up to 5,700 km depending on scenario up to 2020
Network development plan 2022 (50Hertz et al. 2012, p. 116; BNetzA 2012, 2013a, p. 418)	AC: 1,500 km "Startnetz" + 650 km newbuilt DC: 1,600 km newbuilt + 300 km on existing AC corridors	AC: 400 km "Startnetz" + 2,000 km upgrades
Network development plan 2023 (50Hertz et al. 2013b, p. 87; BNetzA 2013a, p. 418)	AC: 1,400 km "Startnetz" + 600 km newbuilt DC: 1,600 km newbuilt + 300 km on existing AC corridors	AC: 300 km "Startnetz" + 2,500 km upgrades
Network development plan 2024 (50Hertz et al. 2014, p. 61; BNetzA 2015a, p. 417)	AC: 1,400 km "Startnetz" + 648 km newbuilt DC: 1,750 km newbuilt + 300 km on existing AC corridors	AC: 500 km "Startnetz" + 2,750 km upgrades

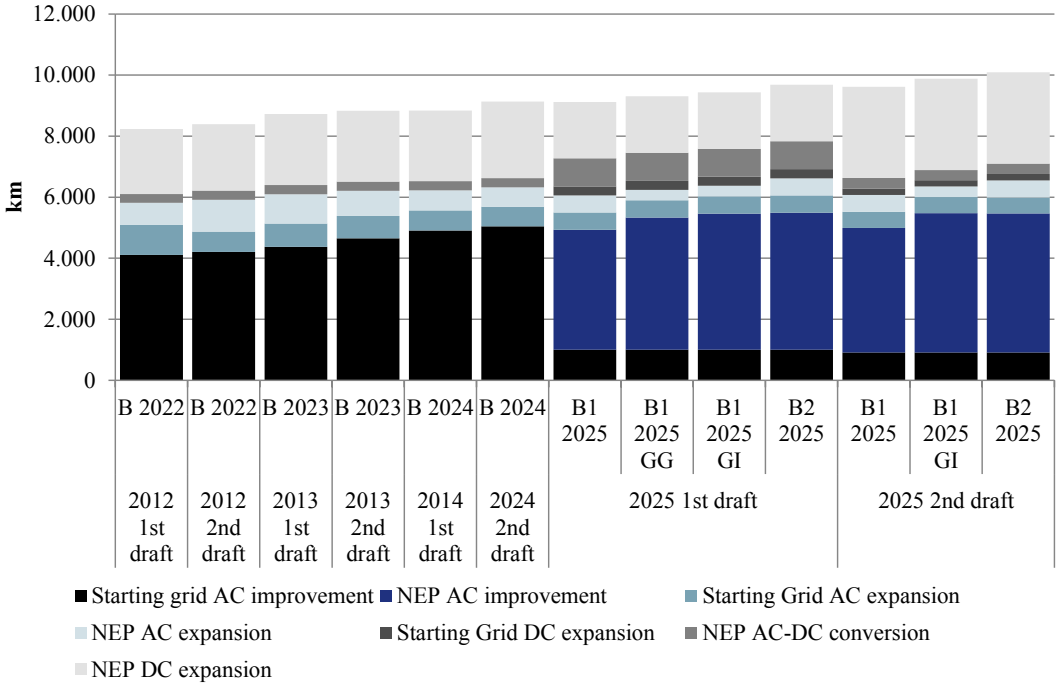


Figure 5.1.: Kilometers planned in network development plans over time
Sources: Network expansion plans (50Hertz et al., 2012, 2013b, 2014, 2016a).

Figure 5.1 shows the number of kilometers planned in the various grid development plans by the TSOs over time.[42] The grid reinforcements amount to about 4,000 km to 5,500 km over time. Leaving the planned high-voltage direct current (HVDC) lines aside, most projects are newbuilt lines or line upgrades in existing corridors. New AC corridors amount to less than 2,000 km, with a slightly declining trend over time. This trend can be attributed the completion of important projects in combination with increased use of the NOVA principle over time, as the various instances of public consultation of the grid development plans showed a clear tendency to not establish new corridors but to instead strengthen the already existing grid.

5.3.2. Development projects onshore and offshore 2012

In order to provide an impression of the physical realities of network development, the results of the 2012 network development exercise, including both onshore and offshore connections, are summarized. The first draft of the TSOs' 2012 network development plan included aggregate network development measures of 6,600 km onshore, corresponding to investments of about €20 bn. The regulator accepted 5,700 km of these lines, including 2,800 km of new builds and 2,900 km of upgrades on existing lines.

A new element of the 2012 planning exercise was the elaboration of an offshore network development plan, called "O-NEP electricity 2013." Offshore connections were previously coordinated in a decentralized manner by the federal states (Lower Saxony and Schleswig Holstein for the North Sea, and Mecklenburg-Pomerania for the Baltic Sea). In the NEP 2012 exercise, coordination was centralized in the national plan under the control of the regulator, BNetzA to ensure closer adherence to the onshore development plan. The Offshore NEP-2013 includes the projects already being implemented, the so-called "starting offshore grid" ("Start-Offshorenetz"), as well as an additional 1,135 km HVDC lines, and 595 km AC-lines in the North Sea, and 370 km AC-lines plus 60 km onshore connections in the Baltic Sea. Figure 5.2 shows the offshore network development plan for the North Sea. Out of the 3,935 km planned, some 1,556 km have been realized (as of early 2016).[43]

5.4. Network expansion during the energiewende

A look at network investment in the German electricity sector appears to support the hypothesis that lack of grid expansion is not a binding constraint to the energiewende. Given an institutional design that favors the complete integration of the merit order,

[42] Only the main scenarios are shown.
[43] In the Baltic Sea, the number of projects is considerably lower.

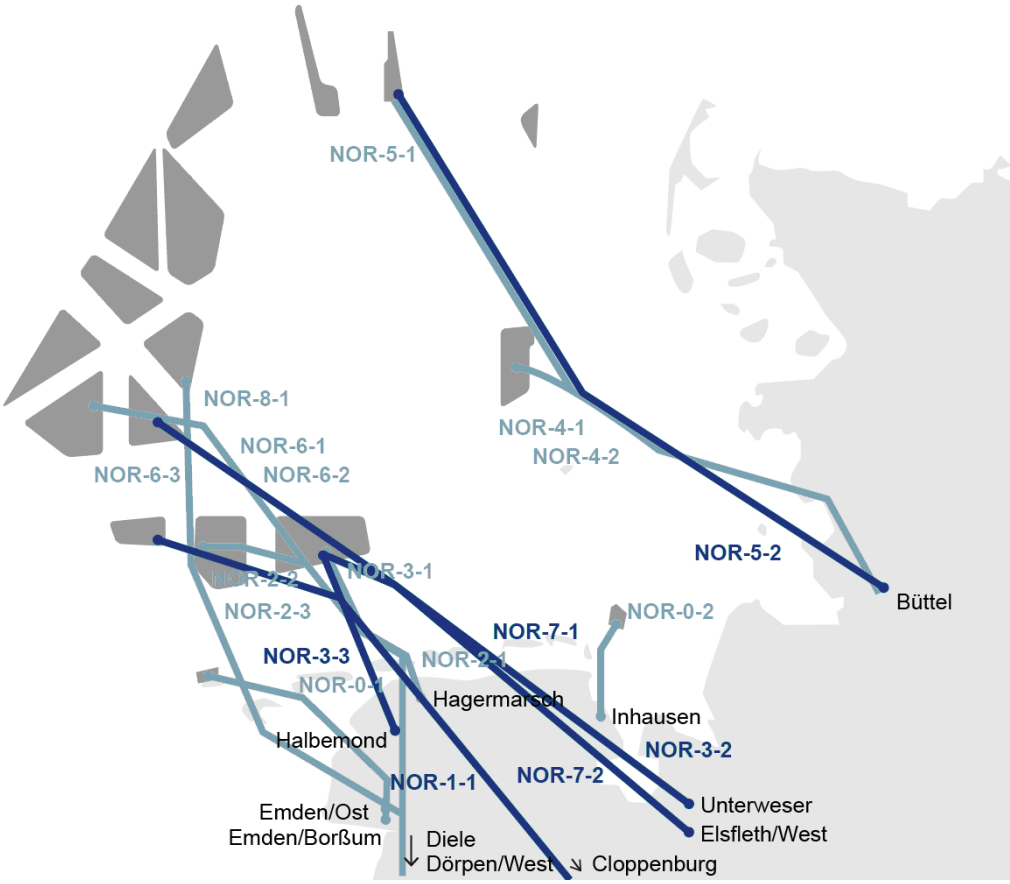


Figure 5.2.: Offshore Network Development Plan (NEP) 2013: Planned offshore network development in the German North Sea.

Legend: The starting grid is light blue; projects of scenario 2023B are dark blue. Source: Gerbaulet et al. (2013a)

in addition to the excessive equity remuneration for TSOs, network extension has proceeded steadily over the last decade. This development appears likely to continue, since there are few issues in transmission network expansion that might create obstacles for the energiewende. This can be shown at three different levels: (1) the aggregate transmission network investments in Germany, (2) the large number of line expansions completed, and, (3) the overall level of network congestion, redispatch requirements, and costs of system services encountered thus far.

5.4.1. Aggregate network investment in Germany

Aggregate investment figures show a constant trend towards slightly increasing transmission investments. Figure 5.3 shows network investments in maintenance and new builds of high-voltage electricity networks. One observes that investments of TSOs gradually increased over time. Some issues were raised by the TSOs regarding

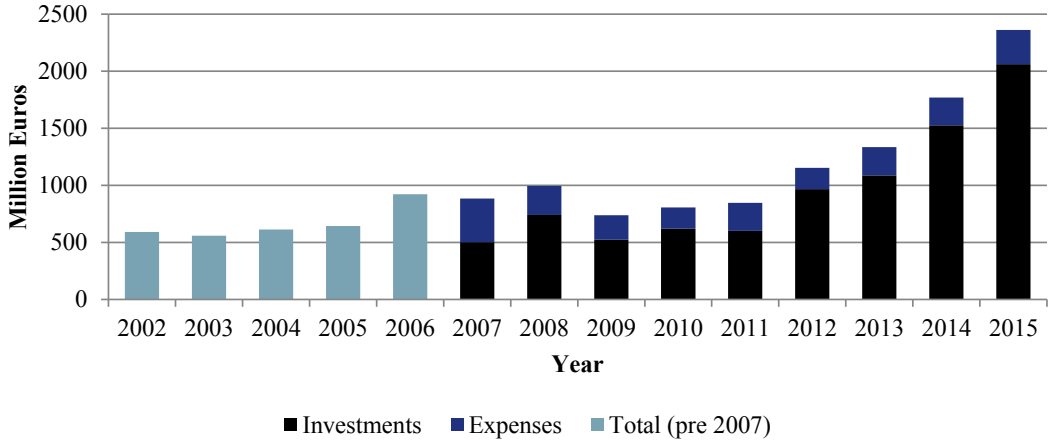


Figure 5.3.: TSOs' network investment over time in Germany
Sources: BNetzA (2007, p. 178, 2013c, p. 53, 2016d, p. 90).

the continuity of the regulatory framework; in particular, the network operator TenneT, a subsidiary of the Dutch state-owned TSO, has complained to regulators of being overburdened by capital expenditures on offshore and HVDC connections.[44] However, these discussions are part of any discussion between investors and regulators; so far, the availability of capital has not been a hindrance to transmission network development.

5.4.2. Implementation of network development plans

A second reassuring sign is the ongoing progress in network development seen throughout the energiewende to date. Both new builds and the expansion of existing lines have proceeded steadily over the last decade. Figure 5.4 and Figure 5.5 summarize developments in the transmission grid as of mid-2016. Almost 500 km of line extensions or new builds were completed between 2009-2015, thus confirming the steady development of the aggregate figures shown above. Three lines connecting the former East and West Germany have been finished, and a large number of local extensions contributed to the smooth development of the network.[45]

The situation of the new HVDC corridors is quite different and more politically charged as well. The first years of the low-carbon transformation at the European level were characterized by a certain "hype" around trans-European HVDC South-North

[44] See ZEIT ONLINE (2011). *Erneuerbare Energien: Stromnetzbetreiber sieht Ausbau von Windparks gefährdet.* November 16, 2011. Hamburg, Germany. URL: `http://www.zeit.de/wirtschaft/2011-11/windparks-finanzierung` (visited on September 15, 2016).

[45] One line was cancelled by a TSO because it was no longer considered required from an energy economic perspective, indicating that not all projects once identified as "necessary" turn out to be required in practice. The EnLAG project No. 22 (Wieder – Villingen) was withdrawn from the network development plan in 2012, the updated EnLAG took effect in July 2013.

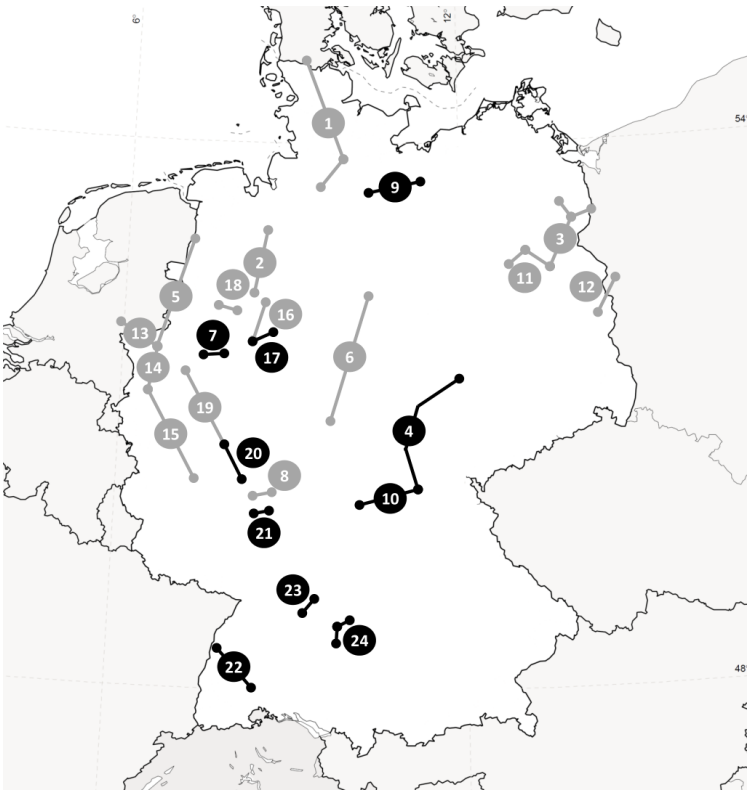


Figure 5.4.: EnLAG Network expansion projects in Germany as of December 2015
Legend: Finished projects are black, unfinished projects gray.
Source: BNetzA (2016c)

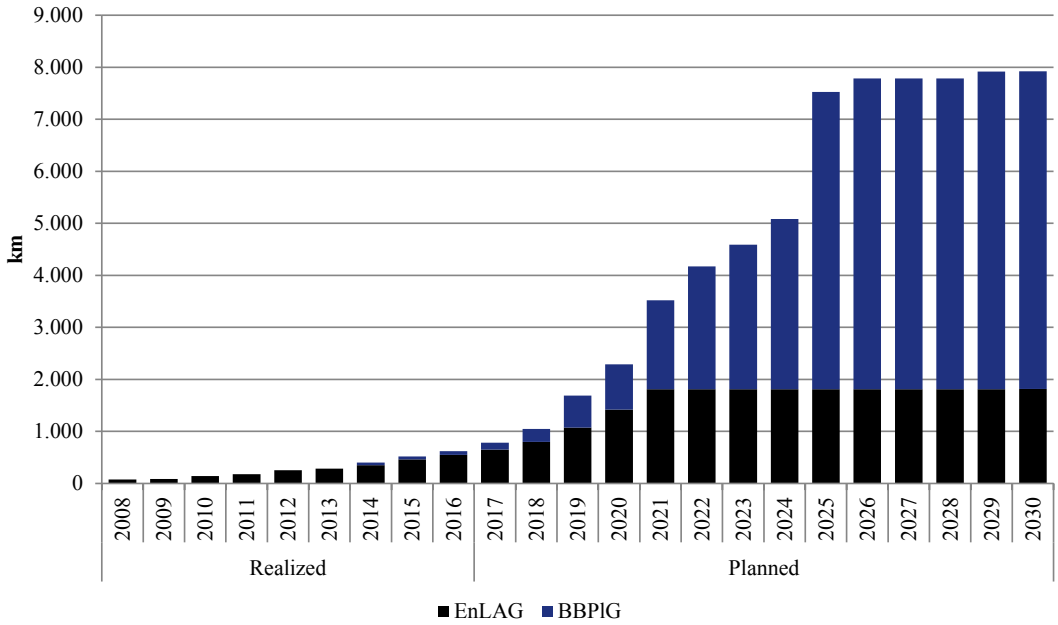


Figure 5.5.: Cumulative realized and planned EnLAG and BBPlG line developments
Sources: BNetzA (2016a,c)

and East-West corridors, even extending to neighboring regions such as North Africa and Russia (Egerer et al., 2009). The inflated expectations have been brought back down significantly since then, but were followed by a similar hype around HVDC lines at the national level (Schröder et al., 2013b). German TSOs have drawn up ambitious plans for HVDC corridors across the country, somewhat emulating the process at the European level.

Figure 5.6 shows the potential siting of four large HVDC corridors that appeared for the first time in the network planning exercise. Most of the four corridors run in a North-South direction. While the northern section of the corridors may have been better suited to renewables integration, the northern section of corridor A was not actively pursued during the first years of the energiewende. In the 2025 iteration of the grid development plan, the northern connection point of corridor D is moved further north to Wolmirstedt, the southern connection point will likely be in Isar. Corridor B having not been considered as essential, and taken out of the network development plan by the BNetzA, a sign that regulatory oversight can lead to adaptations of the NEP.

5.4.3. Levels of congestion, redispatch, and ancillary services

As a result of the network extension, the German electricity system continues to be managed well, which is a logical result of the institutional framework in place. The costs for redispatch have increased slightly with the energiewende. Corrective measures by the TSOs (downward re-dispatch) were for 3.5 terawatt-hours (TWh), 2.5 TWh, 2.2 TWh[46], 2.6 TWh, and 8 TWh in 2011, 2012, 2013, 2014, and 2015; this generally corresponds to less than 1% of total electricity demand, with the exception of 2015, where 1.5% of total demand was reached. The corresponding costs in 2015 were in the range of €402.5 mn for Redispatch and €478 mn for renewable infeed management measures.[47]

Model calculations on network congestion indicate that most redispatch occurs along one corridor running between Thuringia and Saxony in the former East Germany and Bavaria. This congestion occurs mainly in times of simultaneous lignite and wind feed-in, when Thuringia and Saxony are mainly exporting electricity (Mieth et al., 2015a,b). With the finishing and commissioning of one of the EnLAG pilot projects (EnLAG project No. 4), a 380 kV connection (with two circuits) between these two regions (Lauchstädt – Redwitz), this congestion should also be reduced.[48]

[46] The source states 4.4 TWh but accounts for both upward and downward redispatch measures.
[47] For details see the monitoring reports by BNetzA (2013b,c, 2014c, 2015b, 2016d).
[48] Remark: In March 2017 the TSO 50Hertz announced, that redispatch cost in the 50Hertz zone had been decreased from €354 mn in 2015 to about €180 mn in 2016. Reasons for the cost decrease are the commissioning of the EnLAG project No. 4, the installation of phase-shifting

Figure 5.6.: HVDC transmission corridors ("electricity highways") proposed in the 2013 network development plan (NEP 2013)
Source: 50Hertz et al. (2013b)

An additional indicator for the current network situation are the costs of system and ancillary services. These costs summarize efforts by the TSOs to keep the network system in balance at all times, and they include balancing reserves, redispatch and counter-trading, the provision of black-start capacity and reactive power, as well as infeed management, which refers to the costs of cutting the feeding-in of renewables due to network congestion. Figure 5.7 indicates not only a modest absolute level of system costs (in the range of €1-1.4 bn annually) but also a slight decrease in these costs over time. A large part of the cost reduction is attributable to lower costs for reserve energy, which has become more competitive over time.

transformators at the border of Poland and Germany, reduced wind in-feed in 2016, the relocation of bottlenecks towards borders, and the optimization of redispatch processes. (50Hertz, 2017)

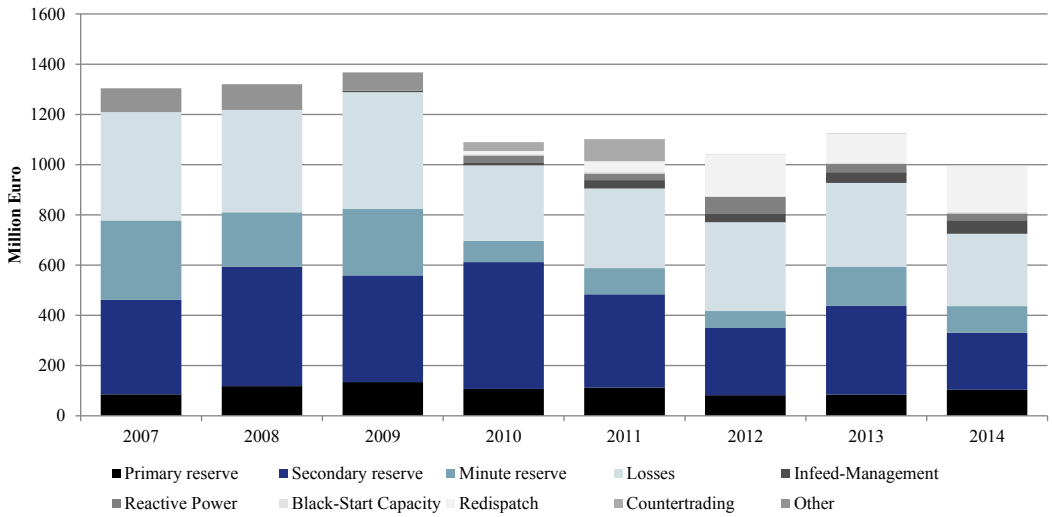


Figure 5.7.: Costs for system and ancillary services
Sources: BMWi (2014b) and BNetzA (2015b)

5.5. Effects from splitting up Germany into bidding zones

5.5.1. Current state of the debate

In the context of network development and Germany's future market design, the question of regionally differentiated electricity prices is raised frequently. The discussion covers the introduction of bidding zones within Germany as well as better coordination with neighboring countries to the North and East among others. Whereas the European Commission and the Agency for the Coordination of Energy Regulators (ACER) appeares to be in favor of internal bidding zones,[49] the German government has regularly voiced its opposition to such a move. An important study conducted on behalf of the network regulator found that the cons of bidding zones outweighed the pros: major disadvantages included the danger of abuse of market power and lower liquidity of the wholesale markets (Consentec and Frontier Economics, 2011). As of mid 2016, all official governmental statements including the "White Book" of 2015 have argued in favor of one integrated bidding zone (BMWi, 2015).

Several studies analyzed potential configurations of bidding zones, but generally without a strong vote in favor of implementing them in practice (see among others Breuer and Moser, 2014; Burstedde, 2012). Studies by the University of Duisburg-Essen suggest the introduction of bidding zones reduces redispatch measures significantly, but positive effects of the market splitting measures are stongly dependent on the actual design of the market split (Trepper et al., 2013, 2015). In

[49] See EC (2014c). *Draft: Commission Regulation (EU) establishing a Guideline on Capacity Allocation and Congestion Management.* Title II, Chapter 2, Bidding zone configuration.

contrast to this, the Institute for Energy Economics of Cologne University (EWI) produced a study in favor of bidding zones.[50]

5.5.2. Bidding zones in Germany would have minor effects

A detailed study on the potential effect of bidding zones for the German electricity market by Egerer et al. (2016b) provides additional quantitative evidence. Logically, because of the incentives given to TSOs explained above, the study reports a low level of congestion, and thus minor potential effects of bidding zones on dispatch and prices. Egerer et al. (2016b) use a variant of the ELMOD electricity model (Egerer, 2016) to calculate the potential effects of bidding zones in a concrete setting that describes the German electricity market in 2012 and 2015. Figure 5.8 shows the distribution of conventional and renewable generation capacity, as well as the potential border between a Northern and a Southern zone: whereas the fossil capacities are mainly located in the North, the distribution of renewables is somewhat more balanced. The model analysis yields small effects from the hypothetical introduction of bidding zones (which they analyzed for 2012 and 2015, respectively): the average price difference between the Northern and the Southern zone is €0.4/megawatt-hours (MWh) in 2012 and €1.7/MWh in 2015, respectively; the latter corresponds to less than 5% of the average wholesale market price.

If a net transfer capacity (NTC) of 8 GW is established between the zones, redispatch is reduced by about 35%. Consumers in the North would have to pay €163 mn less, whereas those in the South pay €275 mn more. The effect on producers is the inverse: producers in the North lose €199 mn (€79 of which is renewables), whereas producers in the South gain €201 mn (€57 mn of which is renewables). The effects of setting up price zones are even reduced when assuming that the high-voltage AC line between Thuringia and Bavaria (so-called South-West interconnector ("SüdWest-Kuppelleitung," Project No. 4) is built. In 2015, this line was still in the process of construction, somewhat behind schedule, but sufficiently advanced to merit such a scenario. The lines, two circuits of 380 kV each or almost 4 GW of capacity, would relieve the congestion between Thuringia and Bavaria significantly. Consequently, the price difference narrows to a mere €0.4/MWh in this scenario, which can be considered negligible and equals the 2012 figure.

The adverse effects of splitting up the German market more than outweigh these minor potential benefits. Not only would the costs of splitting up an efficiently functioning market be high, it would also be difficult to define stable price zones. An important question would be how many bidding zones to create: two (North–South) or

[50] See the commentary by EWI-Director Prof. M. O. Bettzüge (2014). Irreführende Annahme – Marc Oliver Bettzüge schlägt vor, zwei Preiszonen für Strom in Deutschland zu schaffen (Gastkommentar). *Handelsblatt*.

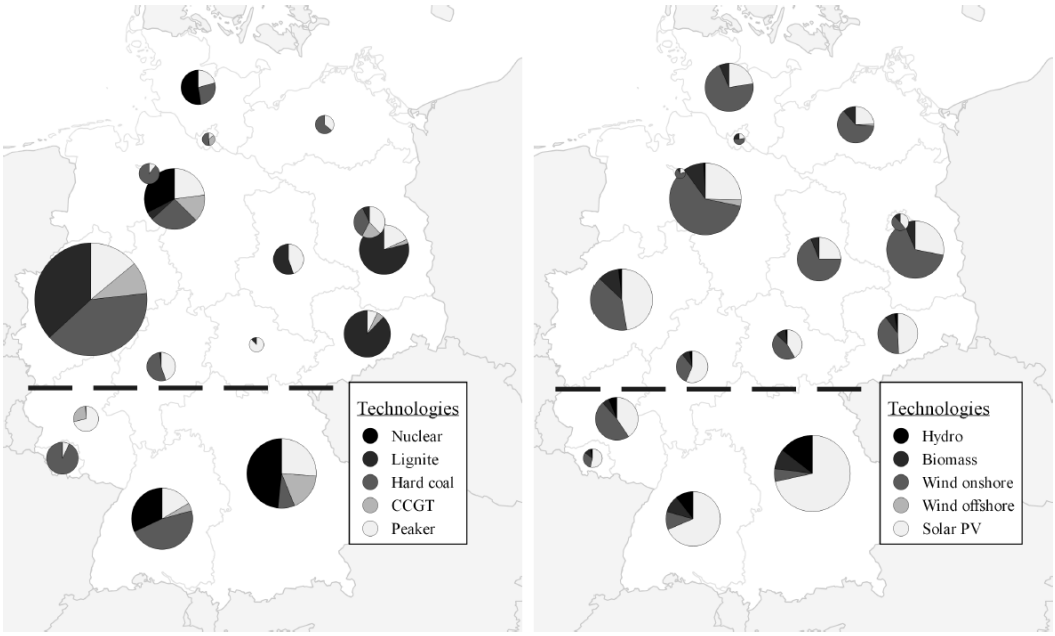


Figure 5.8.: Regional distribution of electricity generation capacities (2012), split between "North" and "South"

Source: Egerer et al. (2016b, p. 374)

three, that is, a zone separating North-Rhine Westphalia from the rest. The liquidity of the market would suffer if an inappropriate market coupling scheme were introduced and, and the high level of integration that has been achieved between the German and the Austrian market would be undermined. Burstedde (2012) highlights that the structure of the zones should appropriately represent the congestion structures in the grid, which can be highly fluctuating and not necessarily occur on with national borders.

5.6. Linking transmission planning and climate targets

As shown in the previous sections of this chapter, electricity transmission expansion has not been central to the successes of the energiewende so far. Yet an interesting development has been taking place in network planning that has gone almost unnoticed: transmission expansion has become an instrument that is now treated as crucial for the attainment of climate goals. In the past, the only objective of transmission was to "connect" supply and demand, and the nature of the transported electricity was disregarded. However, the 2015 network planning exercise introduced *climate* goals into the planning process for the first time, making it clear that electricity networks

also had to serve the objectives of the energiewende, including the greenhouse gas emission reduction targets.[51]

5.6.1. Network planning first ignored GHG emissions

The first network development exercises ignored the GHG emission reduction targets set out in the 2010 energy concept, which had focused on facilitating market dispatch as implied by the merit order principle, which disregards negative climate externalities, except for the CO_2-price. Owing to the low prices for emission allowances in recent years, the Emissions Trading System, the European Union's key tool for reducing CO_2 emissions, did not result in a shift away from lignite and hard coal toward the lower-carbon natural gas in Germany's energy sector. In fact, owing to their power generating costs, lignite-fired power plants were almost always included in the dispatch. This resulted in very high CO_2 emissions, that even increased in 2012-2013, thus risking not to achieve the climate goals of the Energy Concept 2010.

Not only were climate objectives neglected in the early network planning exercises, the TSOs even considered the building of *new* lignite power plants in their scenarios. Figure 5.9 indicates the role of lignite in the draft of the 2015 scenario framework: whereas expected lignite capacities had been progressively reduced in the scenario framework exercises in 2013 and 2014, they increased again significantly in the 2015 plan. Compared to the values in the final approved scenario framework for the 2014 Grid Development Plan, this resulted in an increase in lignite-based capacity in the individual scenarios from 2.0 (scenario C) to 4.3 gigawatt (GW) (Scenario A) for 2025, and 2.6 GW for 2035.

5.6.2. New 2015 scenario framework with emission targets and reduced lignite capacities

In 2014, after the German government announced its climate goals for 2020 and 2050, the electricity sector regulator, the BNetzA, followed suit by imposing CO_2 emission targets on the modeling process for the first time ever in the history of German transmission planning. The 2014 scenario framework, approved by BNetzA in December 2014, contained mandatory emissions restrictions that were in line with the German government's emission targets for the energy sector for 2020 and 2035. The constraint had to be applied by the TSOs and their consultants in the calculation of the energy mix, thus entering the scenario framework and the subsequent network development plan in form of a climate-friendly market result. Concretely, Scenario B2

[51] This section is based on Mieth et al. (2015b) as well as findings from Gerbaulet et al. (2012a) and Reitz et al. (2014).

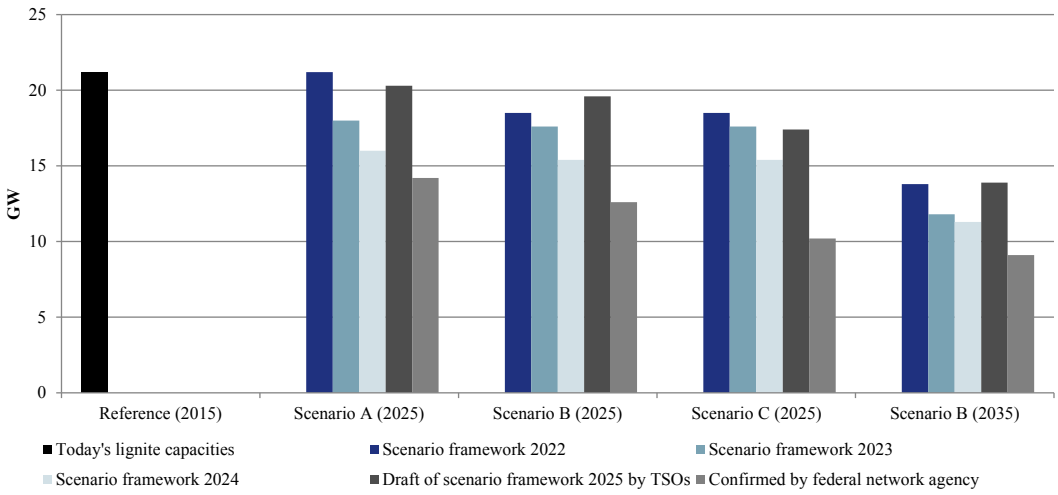


Figure 5.9.: Lignite power plant capacities in the 2015 scenario framework exercise (TSOs' and regulator's perspective)

Source: Mieth et al. (2015b)

prescribed a maximum of 187 and 134 mn tons of CO_2 for 2025 and 2035, respectively. The current draft of the scenario framework (50Hertz et al., 2016a) has an emission limit of 165 Mt and 137 Mt for 2030 and 2035, respectively which is in line with the government's emission targets.

In addition to imposing CO_2 emission targets, BNetzA also cut back on the TSOs' plans for lignite power plants: in comparison to the draft submitted by transmission system operators, the lignite capacities approved by the Federal Network Agency for the 2015 Grid Development Plan were almost five (B 2035) to seven (C 2025) GW lower (see Figure 5.9); the latter equates to a third of the total installed lignite-based generating capacity in Germany. One reason for this decrease is that the BNetzA rejected the transmission system operators' proposal to calculate the service life of power plants based on the periods for which open-cast mines had been approved. Accordingly, lignite-fired power plants were removed from the list of power plants: plans to build new power plants in Profen and Niederaussem in Scenario A 2025 were abandoned and the service life of existing lignite-fired power plants was reduced.[52]

In addition, future grid expansion planning in Germany will include the possibility to curtail up to 3% of the annual production of onshore wind farms and solar power installations. This is in line with the provisions in the Ministry for Economic Affairs and Energy's Green Paper and White Paper on the future development of

[52]The decision to not include new lignite plants in the scenario framework will impact the discussion process about the potential opening of new open-cast lignite mines. In fact, the supposed need for lignite-based power generation was used as the justification of numerous projects, be it the open-cast mining projects Jänschwalde-Nord, Welzow-Süd Teilfeld II, and Nochten 2 (Lusitia), Lützen and Pödelwitz in central Germany, or the downsizing of the Garzweiler II open-cast mine in North Rhine-Westphalia.

the German electricity market (BMWi, 2014a, 2015). This underscores that not "every last kilowatt hour of power generated" should be transmitted but rather that economic motivations should play a more central role in grid planning.

5.7. Conclusions

The electricity transmission infrastructure has an important role to play in the energiewende process. The transmission infrastructure (as well as the distribution infrastructure) is an important element in a renewables-based energy system, as it provides flexibility between different producing technologies, e.g., intermittent renewables and continuous gas plants, and between different regions (e.g., East and West, North and South). Infrastructure is important in any development context, and it is always better to be slightly oversupplied – in particular in periods of system transformation, such as the first years of the energiewende. Taking these concerns further, some transmission system operators have even expressed concerns that electricity transmission is a potential Achilles' heel of the energiewende. The focus on transmission planning, especially the early years of the energiewende, was natural, since the previous system had been highly intransparent and not open to public policy debates. As Ignacio Perez-Arriaga has put it, transmission investment should be as "unexciting" ("boring" or "uneventful") as possible, in order to avoid indecision by investors and high capital costs (Olmos and Pérez-Arriaga, 2009, p. 5286).

This chapter shows that these concerns are less of a concern than stated, and that – on the contrary – transmission expansion demand tends to be overestimated due to incentives provided to the TSOs. Model-based analysis of the German electricity grid, as well as case study experience from close to a decade of almost daily work on the topic, helps to allay fears about the lack of network investment becoming a major barrier to the energiewende. In fact, transmission development has proceeded smoothly over the last years, at normal rate of 50-100 km per year; over 500 km of new lines have been built since 2009, leading to an almost congestion-free system, with the highest quality indicators in Europe.

Looking back over the last decade, electricity transmission in Germany has developed steadily. Important connections have been realized, in particular between the former East and West German grids. Network congestion, once feared to become a critical issue, has remained within tolerable levels. Thus, transmission infrastructure does not threaten to create bottlenecks that could impede or stall the energiewende. The current level of congestion also suggests that splitting up the German electricity network into several zones, debated at the national and European level, is currently not a relevant issue for the energiewende and would also be subject to opposition

from industry and stakeholders in the southern price zone due to fears of rising electricity prices.

This chapter also provided at least two explanations for why transmission expansion has not been an obstacle so far: one is the continued institutional setting of a mostly congestion-free "copper plate" network, where all electricity fed in according to the merit-order principle has to be integrated independently of the location. The other driver is similarly strong, i.e. a rate of return on equity far beyond what can be gained by investing in a project with a similar level of risk. This incentive continues to push the TSOs towards very high levels of grid expansion.

One finding discussed in this chapter that may offer potential for conceptual innovation is that of an explicit link between transmission planning and climate targets. The scenario framework for the 2015 network planning exercise introduced climate goals into the planning process for the first time. Thus, it made clear that, like other parts of the energy infrastructure, electricity networks should be planned following the objectives of the energiewende, including the greenhouse gas emission reduction targets. Previously, the energy mix was taken as given in the transmission planning procedure. Now, the German regulator has introduced an explicit CO_2 target into the scenarios as the basis for network planning. By tightening this constraint over time, the German government should be able to facilitate the achievement of CO_2 emission targets for the energy sector, and at the same time, plan the network effectively to achieve the energiewende objectives.

Chapter 6

Is There Still a Case for Merchant Interconnectors? Insights from an Analysis of Welfare and Distributional Aspects of Options for Network Expansion in the Baltic Sea Region

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This chapter is based on an IEEE conference publication for the 10th International Conference on the European Energy Market (EEM 2013) (Gerbaulet et al., 2013b), and the DIW Berlin Discussion Paper No. 1404 (Gerbaulet and Weber, 2014). A revised version has been submitted to Energy Policy. Previous versions were presented at the 9th Conference on Energy Economics and Technology (ENERDAY 2014) in Dresden, Germany and the 13th European IAEE Conference 2013 in Düsseldorf, Germany.

6.1. Introduction

European electricity policy, driven by market integration and decarbonization targets, sets a strong impetus for expanding transmission networks: European transmission companies identified in their 2016 plans (ENTSO-E, 2016, p. 3) investment needs of roughly 150 bn € until 2030. Although most of the investment can be expected to be regulated, merchant transmission investments are possible within the current legal and institutional framework, but need to be approved on a case-by-case basis by the European Commission (EC). Merchant lines must be financed from the earnings of arbitrage between electricity prices in the two interconnected jurisdictions, while regulated lines are financed by fees raised via grid tariffs overseen by a regulator. Often, and as is the case in the European Union (EU), this status is awarded for a limited period of time; and in practice re-financing of the investment will take place within that period. In light of the large investment needs, some see this option increasing in importance (Cuomo and Glachant, 2012; Makkonen et al., 2015; Mann, 2013; Rubino and Cuomo, 2015). What, however, remains unclear is the role merchant transmission investment can or should play in this context given the backdrop of diverging goals of regulators and investors.

The objective of this chapter is to understand the welfare and distributional impact of "market"-driven transmission investment as compared to both socially optimal (regulated) transmission investment and the absence of additional investment in the European context. We study the problem at the example of the Baltic Sea region, where systems of different energy planning paradigms provide a case for increased interconnection. We find that, somehow contrary to some more stylized analyses, and although merchant investment is lower than in the welfare-optimal case, welfare contribution of merchant investment is roughly 70% of the maximum improvement possible. However, this welfare increase does mainly accrue to the merchant investor as a rent. The argument that merchant investment may be a desirable option if regulated transmission investment is not possible seems to be weakened: From a perspective of distributional aspects, policy-makers might not want to pursue a solution that does not bring any (or very little) benefit to established actors or even reduces their welfare.

6.1.1. Background on merchant transmission investments

Merchant investment into grids have been thoroughly discussed in the literature. Although, in theory, allowing for merchant transmission lines might be an option, Joskow and Tirole (2005) find (by extending stylized models) that in practice problems of asset specificity, lumpiness and market power pose serious problems to the

desirability of merchant interconnectors. In a similar line of reasoning, Kuijlaars and Zwart (2003) and Knops and de Jong (2005) underline the problems of under-investment by merchant investors (as compared to the welfare optimal solution), who only profit when congestion exists. As a remedy to the under-investment problem, Brunekreeft (2005) suggests (regulatory) "capacity checks," i.e. that a regulator imposes minimum capacity requirements on specific projects. From a modeling perspective, e.g. Doorman and Frøystad (2013) and Egerer et al. (2013b) find, for cases of the North and Baltic Seas, that those transmission expansion alternatives leading to the highest welfare contribution cannot be financed by earnings from arbitrage (on which merchant transmission projects would rely) and thus substantiate the theoretical considerations of under-investment and simultaneously call for putting "capacity checks" into context: They are not necessarily capable of enforcing welfare optimal transmission expansion. Further, Joskow (2005) and Turvey (2006) highlight that market driven interconnector investment may overlook reliability aspects while focusing on wholesale-driven economic aspects.

The above findings seem to deliver strong arguments against merchant transmission expansion, which need to be qualified: Regulated arrangements may not always be possible. One reason for this is that if technology is (new and) risky, the regulator may not be able to credibly commit to not expropriate the upside. This would prevent the investment. Gans and King (2004) argue that in such a case, temporary "access holidays" (i.e. an exemption from third party access rules), and thus an exemption from monopoly regulation, may help overcome the investment barrier as the commitment to partially cease regulation could be given more credibly. In addition to enabling investments, they also highlight that such "access holidays" may also be used to set incentives for a quicker delivery of the investment. Beyond the risk-argument, literature (Brunekreeft, 2004; Kristiansen and Rosellón, 2010; Teusch et al., 2012) suggests two more relevant reasons in favor of merchant transmission: first, regulators of the affected jurisdictions might not (want to) agree on redistributive effects of the project and, second, vertically integrated transmission companies could be hindered by the group's management as the project could interfere with the utilities' generation/retail positions.

The inter-jurisdictional coordination aspect is highlighted by Buijs and Belmans (2012), Egerer et al. (2013b), Gately (1974), Nylund (2014), and Tangerås (2012) using both analytic and simulation models: They confirm that coordination of transmission investment can be highly complex. For the concrete case of Scandinavia, Makkonen et al. (2015) discuss a politically-warranted lack of coordination for the planning of transmission lines.

Concerning the second argument, de Hauteclocque and Rious (2011) emphasize that in addition to transmission system operator (TSO) subsidiary companies, which

historically often took on the role of investors, generator companies could also play an important role as merchant investors in Europe.

Another argument is brought forward by Littlechild (2012), who argues in favor of merchant interconnectors on the basis of case evidence. He finds that merchant investment was superior to what regulators attempted to do.

In the EU, however, merchant interconnectors have not played a big role; as of April 2017, only three such projects have been realized, and Cuomo and Glachant (2012) find that the EC has, over time, become more and more reluctant to grant exemptions from regulation. As outlined above, there are still numerous proponents of merchant investments and, hence, the issue cannot be considered "dead;" especially in light of the 2014 exemption granted to the ElecLink project between the United Kingdom (UK) and France.

6.1.2. Our approach

We use a bi-level model set-up to take into account the interdependence between the strategic capacity choices of merchant investors and the welfare-maximizing choices left to the regulated part of the sector. We use a full representation of the extra high voltage (EHV) grid of the region studied, allowing for endogenous, line-sharp transmission expansion while taking into account direct-current load flow (DCLF) principles, bidding-zone-based generation dispatch, and price formation. We do further use a k-means approach to select reference hours to keep the problem computationally tractable. Papers regarding transmission expansion planning exist in the literature.[53] To our knowledge, such a level of detail has not previously been used to study the impact of merchant investments.

The remainder of this chapter is structured as follows: Next, Section 6.2 outlines the respective optimization problems of merchants and regulators and the model applications used in this chapter. Section 6.4 describes the application and relevant input parameters. The results of the application are discussed in Section 6.5. Section 6.6 concludes.

[53] The contributions by Egerer et al. (2013b, 2016a), Garces et al. (2009), Gil et al. (2002), Pozo et al. (2013a), Pozo et al. (2013b), Sauma and Oren (2006), and Sauma and Oren (2007) describe transmission expansion models, corresponding incentive schemes, and analyzes of transmission investments' socio-economic impact. While the transmission investment in these papers is conducted by either profit-maximizing investors or benevolent planners, the interaction between investments of both profit-maximizing investors and welfare-maximizing social planners on the same electricity grid is not analyzed.

6.2. Model

We implement a model with a line- and node-sharp representation of the high-voltage alternating current (HVAC) grid as well as high-voltage direct current (HVDC) lines, and connected power plants and renewable infeed. While the power plant portfolio is assumed as given in this setting, the HVAC and HVDC lines can be expanded. Power plant dispatch and pricing is done on a zonal level while still allowing for inter-zonal grid expansion as part of a novel model formulation presented in this chapter.

We model the interaction between the two parties as a two-stage game where the merchant's optimization problem is solved taking into account the reaction of the regulator. We first assume that there is only one merchant investor. This implies that the merchant is first-mover in this game, i.e. the *Stackelberg* leader. Although this set-up seems to be very preconditioning, it yields interesting results that remain stable when the Stackelberg assumption is relaxed later on.

The regulator in our model seeks to minimize overall cost of the electricity system by controlling power plant dispatch and deciding on transmission expansion in the HVAC grid. Power plant dispatch follows a zonal approach, as currently implemented in Europe.

Merchants that plan and build cross-border lines have a different objective. Their goal is to maximize profit (i.e. their congestion rent), which is the congestion revenue minus the line investment cost. Congestion revenue accrues when prices between two connected zones differ. The price difference on the merchant's line multiplied by the amount of energy transmitted is the congestion revenue. As (operational) withholding of capacity is not an option within the EU legislation, this alternative is not considered.[54]

To conduct our analysis, we compare three scenarios; the merchant solution and two extreme scenarios. First, an *AC Only* case, where no HVDC expansion is possible, but plant dispatch and HVAC investment is made in a cost-minimizing way. Then the *Stackelberg* case where the merchant acts as a first mover in building HVDC lines (aniticpating the reaction of the regulator), then the regulator follows in building the HVAC grid. The reason for limiting the merchant's choices to HVDC transmission is in European legislation: Art. 17 of EC 714/2009 does foresee non-HVDC transmission projects to be granted an exemption from regulation only in very exceptional cases.[55] The third scenario is the *Fully Planned* case, where we assume a cost-minimizing,

[54] Yet, Brunekreeft and Newbery (2006) argue that allowing capacity withholding during operation in the exemption period could reduce problems of under-investment. Boffa et al. (2015) are more critical about this consideration.

[55] This seems to be motivated by the idea that 'new' and therefore 'risky' technologies could justify some kind of regulatory restraint, as discussed in Section 6.1.1.

central regulator who conducts plant dispatch and network expansion for both HVAC and HVDC lines. These three different scenarios are introduced in Section 6.3.

6.2.1. The regulator's optimization problem

The regulator's objective is to minimize system cost, by coordinating both dispatch and network expansion. Although the regulator has a global view, he may not be able to conduct transmission investment between all systems, thus limiting his powers and mimicking the inability to coordinate cross-border investment.

Power plant dispatch is conducted on the basis of bidding zones, i.e. transmission is not priced within zones. Transmission is modeled following DCLF principles (Leuthold et al., 2012; Schweppe et al., 1988; Stigler and Todem, 2005). Transmission expansion problems in electricity networks are typically non-convex. We apply the linear relaxation provided by Taylor and Hover (2011), to keep the model setup linear, while still allowing for an approximation of the changes in line-flow characteristics that occur when investments into the HVAC grid take place. The flow in the existing network strictly follows DCLF principles mentioned above, whereas the flows through the endogenously added HVAC lines must be approximated. Equations (6.1)–(6.11) show the regulator's optimization problem. The complete nomenclature is given in C.1.

The regulator's objective (6.1) is overall cost minimization. It consists of the generation cost $\sum_{s,bz,t} C_s q_{s,bz,t} W_t$ as well as the grid expansion cost $\sum_l I_{lr} exp_{lr}$. The power plant dispatch is determined in (6.2) by constraining the electricity generation $q_{s,bz,t}$ per technology and bidding zone. This allows for a zonal power plant dispatch, which is disaggregated in (6.4) to a nodal dispatch. Further, (6.3), for hydro generation, the available energy is constrained using historical full-load factors (cf. Lipp and Egerer, 2014).[56]

$$\min \sum_{s,bz,t} C_s q_{s,bz,t} W_t + \sum_l I_{lr} exp_{lr} \tag{6.1}$$

s.t.

$$0 \geq q_{s,bz,t} - \sum_{bz:(n \in bz)} Q^{\max}_{s,n} \qquad \forall\, s, bz, t \tag{6.2}$$

$$0 \geq \sum_t q_{s,bz,t} W_t - Hflf_{bz} \sum_{bz:(n \in bz)} Q^{\max}_{s,n} \qquad \forall\, s = \{\text{HYDRO}\}, bz, t \tag{6.3}$$

[56] We do not require all the potential energy to be used, i.e. 'spillage' is implicitly allowed.

The network is connected by an incidence matrix $Inc_{l,n}$, assigning line end points to nodes n. Voltage angles are expressed by $\delta_{n,t}$, the relative line susceptance is denoted as B_l. Each node's energy balance is enforced in (6.4) where nodal generation, demand, flows of existing HVAC lines (angle difference $\sum_{nn} \delta_{nn,t} Inc_{lr,nn}$ times B_{lr}), flows on additional HVAC lines $\zeta_{lr,t}$, and HVDC line flows $\zeta_{lm,t}$ are taken into account. Residual demand $D_{n,t}$ is actual demand minus the feed-in of wind and photovoltaics.[57] Lines l are regulated HVAC lines $lr \in l$ and merchant HVDC lines $lm \in l$. For each synchronous area, a slack node is defined through (6.5) to ensure a unique solution during the optimization.

$$\begin{aligned} 0 = &+D_{n,t} - \sum_{s,bz:(n \in bz)} \left[Q^{\max}_{s,n} \frac{q_{s,bz,t}}{\sum_{nn \in bz} Q^{\max}_{s,nn}} \right] \\ &- \sum_{lr} \left[Inc_{lr,n} \left(\zeta_{lr,t} + B_{lr} Exp0_{lr} \sum_{nn} \delta_{nn,t} Inc_{lr,nn} \right) \right] \qquad \forall\, n,t \qquad (6.4) \\ &- \sum_{lm} \left[Inc_{lm,n} \zeta_{lm,t} \right] \\ 0 = &\ \delta_{n,t} Slack_n \qquad \forall\, n,t \qquad (6.5) \end{aligned}$$

For the HVAC lines in the system, (6.6, 6.7) impose the relevant thermal limits onto the phase angle differences. Here, $F^{\max}_{lr}$ denotes the thermal limit of existing line lr, whereas M^{ζ}_{lr} shows the lower bound given by parallel paths.[58] M^{ζ}_{l} is determined by applying a Dijkstra-Algorithm (1959) onto the electrical network. Using $\min\{M^{\zeta}_{lr}, F^{\max}_{lr}\}$ as part of the model formulation in (6.6) and (6.7) instead of just the existing thermal limit $F^{\max}_{lr}$ is not required per se, but helps to decrease the solution space, which speeds up the model. Upper and lower limits of expansion in the HVAC-grid are expressed by (6.8) to (6.11), where (6.8) and (6.9) impose maximum limits on the flow through the endogenously added lines, using the expansion factor exp_{lr}. Here, a value of 0 means no expansion and a value of 1 determines doubling the existing lines' capacity. (6.10) and (6.11) impose minimum limits on the flow based on maximum line expansion factors $\overline{Exp}_{lr}$ and are calculated based on Taylor and Hover (2011). We set a limit of five for $\overline{Exp}_{lr}$, which is sufficiently high to not be a constraint.

$$0 \geq B_{lr} \sum_{n} \delta_{n,t} Inc_{lr,n} - \min\{M^{\zeta}_{lr}, F^{\max}_{lr}\} \qquad \forall\, lr,t \quad (6.6)$$

[57] Curtailment of wind and PV has not shown to be necessary/benefical, due to the moderate level of installed capacity.

[58] Parallel paths may impose lower flow limits when their thermal limit is hit earlier.

$$0 \geq -B_{lr} \sum_{n} \delta_{n,t} Inc_{lr,n} - \min\{M_{lr}^{\zeta}, F_{lr}^{\max}\} \qquad \forall\, lr, t \quad (6.7)$$

$$0 \geq -\zeta_{lr,t} - \min\{M_{lr}^{\zeta}, F_{lr}^{\max}\} exp_{lr} \qquad \forall\, lr, t \quad (6.8)$$

$$0 \geq \zeta_{lr,t} - \min\{M_{lr}^{\zeta}, F_{lr}^{\max}\} exp_{lr} \qquad \forall\, lr, t \quad (6.9)$$

$$0 \geq B_{lr} \sum_{n} Inc_{lr,n} \delta_{n,t} \overline{Exp}_{lr} - \zeta_{lr,t} - \min\{M_{lr}^{\zeta}, F_{lr}^{\max}\}[\overline{Exp}_{lr} - exp_{lr}] \qquad \forall\, lr, t \quad (6.10)$$

$$0 \geq -B_{lr} \sum_{n} Inc_{lr,n} \delta_{n,t} \overline{Exp}_{lr} + \zeta_{lr,t} - \min\{M_{lr}^{\zeta}, F_{lr}^{\max}\}[\overline{Exp}_{lr} - exp_{lr}] \qquad \forall\, lr, t \quad (6.11)$$

The flows on merchant lines are dispatched by the regulator, conditions (6.12, 6.13) impose the respective flow limits: $Exp0_{lm}$ denotes existing the lines' capacity in megawatt (MW), while exp_{lm} is the endogenously determined capacity expansion built by the merchant.

$$0 \geq \zeta_{lm,t} - exp_{lm} - Exp0_{lm} \qquad \forall\, lm, t \quad (6.12)$$

$$0 \geq -\zeta_{lm,t} - exp_{lm} - Exp0_{lm} \qquad \forall\, lm, t \quad (6.13)$$

6.2.2. The merchant's optimization problem

The merchant tries to optimize his profit, which consists of the congestion rent on a line minus the expenditure needed to build the corresponding lines. The merchant's profit maximization problem is shown in (6.14) to (6.16).

$$\max_{exp_{lm}} \left(\sum_{lm} exp_{lm} \left[\frac{\sum_t \zeta_{lm,t} pD_{lm,t}}{Exp0_{lm} + exp_{lm}} - I_{lm} \right] \right) \quad (6.14)$$

s.t.

$$pD_{lm,t} = \sum_{\substack{\forall n,nn,bz,bzz: \\ Inc_{lm,n}=1, n \in bz \\ Inc_{lm,nn}=-1, nn \in bzz}} (p_{bz,t} - p_{bzz,t}) \qquad \forall lm, t \quad (6.15)$$

$$exp_{lm} \geq 0 \qquad \forall lm \quad (6.16)$$

The profit of the merchant is determined in (6.14), where the flow is multiplied by the zonal price difference and subtracted by the investment cost of lines. In case the merchant expands previously existing lines, he only receives the share of the congestion rents relative to his capacity addition. Both the flow on regulated and

merchant lines is determined by the regulator. Thus, the price $p_{bz,t}$ and the price difference between nodes $pD_{lm,t}$ in (6.15) are a result of the regulator's optimization problem. In our modeling, the price is calculated as the zonal average of the nodal balance marginals, i.e. the average cost of supplying one additional MWh on any node of the respective bidding zone. Deviations from the merit order list are allowed on a zonal level, if cheaper than transmission expansion. This replicates the effect of (costly) redispatch endogenously.

6.2.3. Model implementation

This two-stage model set-up translates into a mathematical problem with equilibrium constraints (MPEC). For sufficiently small problems, MPECs can be solved by expressing the follower's problem(s) in their Karush-Kuhn-Tucker (KKT) form. The computational difficulty lies in quickly solving the complementarity problem (Gabriel and Leuthold, 2010). Often this can be done efficiently with the help of disjunctive constraints, such that the MPEC can be solved as a mixed integer linear program (MILP), for which a large range of solvers is available (Leuthold et al., 2012).

The MPEC of this chapter when applied to the real system of the Baltic Sea Region is too complex for the traditional, integrated approach of directly solving the problem, as the number of nodes and lines leads to a model complexity that far exceeds the usual size of MPECs. Using a disjunctive constraints formulation is theoretically possible, but the integrated model's feasible solution space would be a single point, and it would contain binary variables in the order of magnitude of more than 100,000. As the theoretical complexity (not taking into account optimizations such as branch-and-cut and other heuristics) would be $2^{100,000}$, finding the solution would be challenging.

To avoid this problem, the solution space for the merchant's upper-level investment decision is discretized and all possible investment combinations are evaluated by solving the regulator's corresponding lower-level linear program (LP). The merchant's optimization problem is therefore not directly part of the solution process but calculated after solving the lower-level LP. Then, the profit maximizing choice is selected by evaluating all lower-level outcomes. The discretization of the investment options leads to a slight loss in precision because the global optimum could lie between two integer steps. As real HVDC projects actually come in steps, with some minor exceptions for smaller projects, this inaccuracy is negligible. Further, this approach also eliminates difficulties that the bi-linearity in (6.14) would pose to integrated solution approaches. Another advantage of this approach is being able to analyze the outcomes of the merchant's entire solution space. This allows us to weaken the

Stackelberg assumption and determine the effect of investment combinations that are less-than-optimal from a merchants perspective.

The overall model setup is similar for the two non-Stackelberg scenarios. Here either the full set of all lines (*Fully Planned*) or just the set of HVAC lines (*AC Only*) is visible to the regulator.

6.3. Scenarios

Als aready noted, we compare three scenarios to analyze the effect of different grid expansion approaches:

1. *AC Only*: No new HVDC lines are allowed; only a fully coordinated regulator may expand HVAC-lines between adjacent countries, i.e. interconnection between non-synchronous areas is not enhanced,
2. *Stackelberg*: The Stackelberg-game is modeled; merchant is first-mover for HVDC lines; regulator is follower for HVAC connections and dispatch,
3. *Fully Planned*: All lines (HVAC and HVDC) are expanded on a cost-minimizing basis by the (global) regulator.

The rationale behind this set-up is to identify how well the second best solution of allowing merchants to build HVDC lines performs, both in terms of total cost and allocation of rents to producers, consumers, and merchants. For the calculation of consumer rents, it is necessary to make assumptions for the consumer's willingness-to-pay (WTP). Here, we assume a WTP of 180 €/MWh, making sure this limit is never hit. This is sufficient, as we are not interested in absolute but rather relative welfare changes.

6.4. Model application to the Baltic Sea region

We apply the model to the electrical system of the Baltic Sea neighboring countries (Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Poland, and Sweden) in 2020. Additionally, we take into account the "non-core" countries, i.e. the Netherlands, Austria, Belgium, the Czech Republic, France, Italy, Luxembourg, Norway, and Switzerland which we model as single nodes. HVAC lines from/to these countries are not expanded, but fixed at their prospective net transfer capacity (NTC) values. An overview of the network and bidding zones is given in Figure 6.1, taking into account bidding zones in Sweden (Svenska Kraftnät, 2011) and Norway, as well as publicly available plans for both generation and network through 2020.[59]

[59] The LitPol interconnector between Lithuania and Poland is in operation since 2015. However, for the analysis in this paper we assume that this be not (yet) the case.

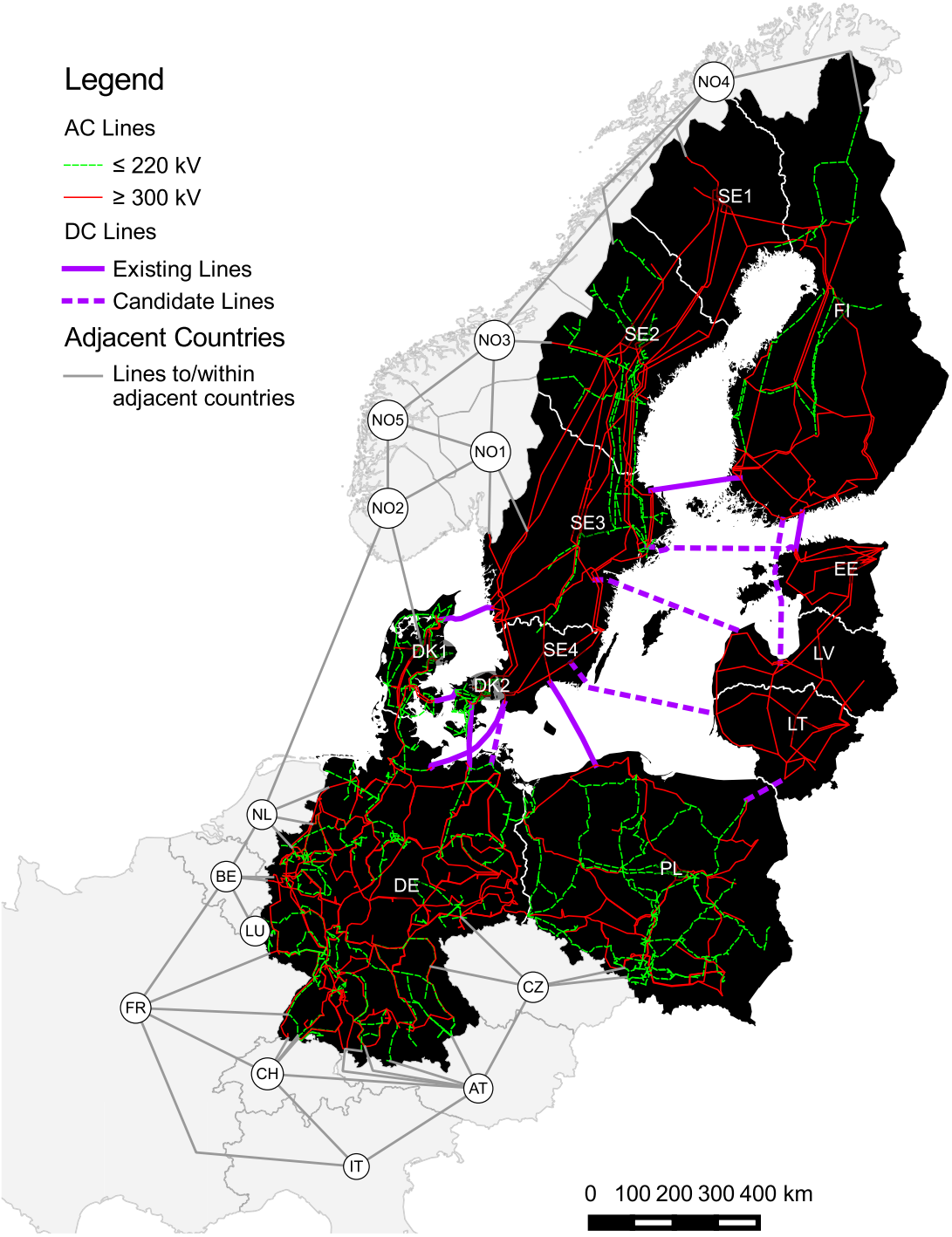


Figure 6.1.: Model region and network. Projection in TM Baltic 93, Source: Own depiction using shapefile data from Eurostat, SvK, ENTSO-E.

We apply information from the European Network of Transmission System Operators for Electricity (ENTSO-E). As a starting point we use the Ten-Year Network Development Plan (TYNDP) by the including the Scenario Outlook and Adequacy Forecast (SOAF) by ENTSO-E (2012b,d), assuming Scenario "B" 2020, and the Baltic Energy Market Interconnection Plan (BEMIP) from CESI (2009) and EC (2009a, 2012a). Further, we use diverse sources on generation, load, and networks as set out in Section 6.4.1.

6.4.1. Data

Generation data

Generation technologies considered in our model are both dispatchable and non-dispatchable variable renewable energy sources (VRE). For dispatchable generation, power plant data from PLATTS (2011) and CARMA (2013) is used as a basis for the spatial distribution of technologies within the electricity grid. For VRE generation, locations and distribution of installations are determined using Nomenclature des unités territoriales statistiques (NUTS)-2 potential maps from ESPON (2010, pp. 226), except for Germany, where detailed data on installation sites is available from the TSOs. The resulting distribution of generation capacities is, subsequently, scaled according to SOAF-data using a brownfield approach. For dispatchable generation, fuel and carbon prices are taken, where applicable, from the "Current Policies Scenario" of IEA's World Energy Outlook (IEA and OECD, 2011, pp. 64, 66), in line with the assumptions of the Baltic Regional Investment Plan of the 2012 TYNDP (ENTSO-E, 2012a, p. 38); cf. Table 6.1. For Hydro (reservoirs) no explicit electricity generation costs are assumed, but maximal energy is restricted to an average historical full-load factors, which are derived from ENTSO-E data. Availabilities of conventional generation capacity are taken from a TSO assessment (50Hertz et al., 2013a, p. 32). Efficiencies and further assumption are based on a Data Documentation by Egerer et al. (2014). Pumped storage is modeled as hydro electricity generation, to be able to replicate the general usage pattern of hydro electricity storage when using reference hours (cf. Section 6.4.2).

The base-year for all time-series in this chapter is 2012. VRE feed-in time-series for all 8,784 hours of 2012 are taken from the respective TSOs (50Hertz, Amprion, Augstprieguma tīkls, Elering, Energinet.DK, Litgrid, Svenska Kraftnät, TenneT, TransnetBW). These time series are corrected to meet historical full load hours (FLH) for the different technologies and spatially distributed over the nodes using the installation data on a NUTS-2 level. If more than one node per NUTS-2 region is present, VRE feed-in is split evenly among them. As VRE is considered as non-

Table 6.1.: Fuel cost, including a carbon cost markup of 10 €/t_{CO_2}.

Fuel	**Cost [€/MWh$_{th}$]**
Uranium	3.00
Lignite	13.05
Steam Coal	17.82
Natural Gas	32.55
Oil	45.02
Biomass	7.00
Waste	7.00

dispatchable, it is subtracted from load to obtain a residual load curve per node. For the "non-core" countries the feed-in time-series are calculated based on weather data from Dee et al. (2011).

The electricity grid

The electricity grid is represented with two different resolutions in our model. In the core region, the actual line-sharp EHV grid is modeled; the "non-core" countries are modeled as a aggregated nodes.

The starting grid for the core region that is assumed for 2020 in this application is based on the ENTSO-E grid map (ENTSO-E, 2011) and includes all mid-term TYNDP projects with completion dates between 2012 and 2016 (ENTSO-E, 2012d). Although this chapter is set in 2020, we assume slight delays in the completion of the grid development projects. Therefore the long-term projects that – according to the TYNDP – should be built between 2017 and 2022 are not included part of the starting grid. This results in a grid with 1,281 HVAC lines. In addition, we include the Ambergate project listed in the BEMIP, connecting SE3 (Norrköping) and LV (Ventspils) (CESI, 2009; EC, 2009a, p. 10), the Hansa PowerBridge project between Germany and Sweden, as well as two hypothetical connections between Estonia and Sweden (EE-Haku and SE-Stockholm), and Finland and Latvia (FI-Inkoo and LV-Bisuciems). In order to take into account the N-1-criterion of network operation, all HVAC lines are allowed to use no more than 70% of their nominal capacity as suggested by 50Hertz et al. (2012, p. 102).

The representation of the "non-core" countries is simplified to nodes aggregated by bidding zones, which are coupled using net transfer capacities. The values for the NTCs are based on ENTSO-E (2013b) with additional information from ENTSO-E (2014c) and BNetzA (2014a). As no spatial representation within these bidding zones is needed, the total generation portfolio and load is aggregated. Thus only imports and exports influence the flow on the cross-zonal lines, which are modeled with direct current (DC) characteristics.

Load data

Hourly load data for 2012 is taken from ENTSO-E (2013-2016) and is scaled up to annual consumption levels of the SOAF's B-2020 scenario. Load-shedding is allowed, at a price of 2000 €/MWh, but does not occur in our application.

Investment cost

Investment costs for the expansion of the HVAC and HVDC lines are adapted from data provided in the German network development plan (50Hertz et al., 2013b, p. 364). HVDC installations are assumed to have identical per MW, per km cost for subsea and onshore overhead installations, as the share of subsea and onshore lengths are roughly equal for most lines considered. The data are given in Table 6.2.

Table 6.2.: Grid investment cost.

Grid Technology	Cost	Unit
AC overhead line (2 systems)	1.4	M€/km
DC line	700	€/(MW×km)
DC converter station	130	€/kW

Source: 50Hertz et al. (2013b, p. 364).

For HVDC installations, a recovery period of 20 years is assumed, which is in line with the (recent) exemptions granted by the EC. For HVAC installations, 30 years are taken into account.

6.4.2. Reference hours

As we rely on a complete enumeration of the merchant's (discretized) solution space, each LP subproblem needs to be solved sufficiently fast. Therefore, it is not feasible to calculate the model for, e.g. a full year of 8,760 hours. We focus our analysis on eight reference hours to account for the variability of load and intermittent renewables feed-in. To select those reference hours, we apply a k-means clustering approach in order to identify hours that best represent typical situations of load and VRE-infeed.[60] The resulting clusters are not necessarily of the same size; therefore, we take into account a weight factor that corrects for the "duration" of the reference hour. Although the number of reference hours used in this application is comparatively low we can show that we obtain stable results for the merchant's investment decision for $N \geq 7$. This

[60] The approach to use reference hours, or reference cases is widespread in modeling. Specifically, we calculate (using R software; R Core Team, 2012) our clusters based on overall system load and intermittent VRE feed-in. The k-means approach is used to identify reference data for modeling electricity systems, e.g. by Green et al. (2014) and Munoz et al. (2016). Other clustering approaches can be found in Després et al. (2017) and Nahmmacher et al. (2016).

approach neglects extreme hours of load and renewables infeed. We abstract from these hours, as the economic merchant decision of investing in infrastructure is not influenced by extreme events but overall profitability.

6.4.3. The merchant's investment choices

As noted in Section 6.2.3, we discretize the merchant's action space in order to overcome the computational difficulties of bi-linearity and of the integrated solution of the MPEC, i.e. reformulating the lower level into its KKT form. We choose the following approach to select the investment choices available to the merchant investor:

1. First, we select the non-zero HVDC expansion decisions of the *Fully Planned* case that are equal or greater than 250 MW. These are the candidate lines that the merchant investor is entitled to invest in.

2. For the candidate lines, we allow the merchant to invest in steps of 250 MW, from 0 to four 250 MW steps beyond the *Fully Planned* extension level, and including the exact value of the fully planned level.

This discretization results in 39,200 investment alternatives. The overall MPEC was solved on a computing cluster, using GUROBI and each of the LPs consumed about 125 seconds of CPU time.

6.5. Results and discussion

In this section, we present and discuss our results. First (Subsection 6.5.1), we present the general outcomes of the model runs. Second, we analyze the impact of the merchant's decision under the Stackelberg game (Subsection 6.5.2). Third, in Subsection 6.5.3, we relax the Stackelberg assumption by taking a look at the larger set of investment options, most still profitable from a merchant perspective, but less extreme than the Stackelberg optimum. This section closes with remarks on the results.

6.5.1. General results

As expected, total system costs are lower in the case of full coordination (*Fully Planned*) than in the absence (*AC Only*), while costs of the *Stackelberg* scenario are in between. The differences result from different decisions on plant dispatch and investment into HVDC and HVAC transmission investment; all costs are given in Table 6.3.

Table 6.3.: Costs of all scenarios in mn € p.a. Transmission expansion costs are annuities.

mn € p.a.	**Generation Cost**	**AC Expansion Cost**	**DC Expansion Cost**	**Total Cost**
AC Only	46,404	211	-	46,615
Stackelberg	46,367	199	8	46,574
Fully Planned	46,346	187	24	46,557

Source: Own calculations.

As for the plant dispatch, the resulting generation per country and by technology are shown in Figures 6.2 and 6.3, while the import/export balances of countries are presented in Figure 6.4. As opposed to other "non-core" countries, Norway is included in the diagrams as it is clearly affected by the modelled decisions. The fuel mix employed in the different countries is very close to the current situation. Germany is, despite its decarbonization efforts, dependent on generation from coal in 2020, while Denmark uses coal only to a little extent to complement its otherwise very "green" generation from wind and biomass. In the Baltic States (Estonia, Latvia, and Lithuania, see also Figure 6.3), Estonian generation (mainly from oil shale, modeled here as "Lignite") helps to cover both Latvian and Lithuanian demand (cf. Figure 6.4). Hydro power plays some role in these countries, complemented by a growing share of wind generation. Polish generation is heavily coal-based – even more than generation in Germany in relative terms, but not in absolute amounts. Further, wind, hydro, and biomass contribute to Polish generation to some (limited) extent. The practically purely hydro based power generation in Norway is complemented by some wind generation in amounts comparable to those of Sweden and Poland. Finnish and Swedish generation strongly rely on nuclear energy (as compared to the other "core"-countries). Power production in Finland is further composed of some hydro, a relatively small amount of wind, biomass and some coal. Yet, in contrast to Finland, generation from hydro resources clearly plays a more dominant role in Sweden.

The most remarkable change in generation occurs in Poland and Finland: While Polish power production from coal decreases from *AC Only* over *Stackelberg* to *Fully Planned*, Finnish (and Danish) power production increases. Further, Sweden's hydro production decreases weakly while Germany's production increases slightly.[61] The main effects on cost-saving are in replacing production from older Polish power plants by production from more recent plants in Finland and Denmark (and Germany). Additionally, generation from combined cycle gas turbines (CCGTs) (in Germany, cf.

[61] These changes are due to transmission expansion costs and the implicit possibility of spillage. However, changes are very small, which is intuitive.

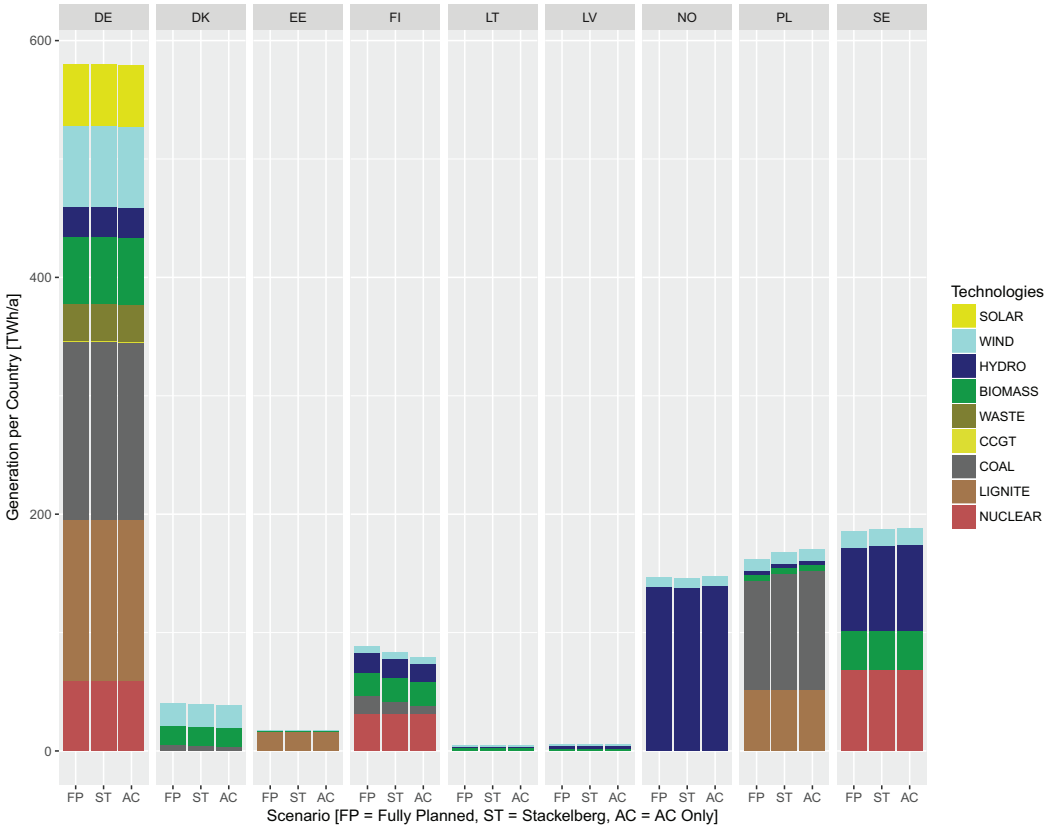


Figure 6.2.: Structure of generation dispatch in the Baltic Sea countries plus Norway. Source: Own calculations.

Figure 6.3) is slightly reduced and replaced by coal. Strikingly, power production in the Baltic States is generally unaffected, as can be observed from Figure 6.3. This, however, may change if the "cheap" generation from oil shale in Estonia is replaced by more environmentally friendly generation. Although the relative changes are, from a country perspective, considerable, aggregate exchanges are not fundamentally affected: Importers stay importers and exporters stay exporters, as can be seen from Figure 6.4. However, the (coal) generation shift from Poland to Finland and Denmark is clearly reflected in the exchange balances. In line with the aforementioned, prices in Finland increase, while they decrease in Poland, and overall, they converge: The standard deviation of average bidding zone prices is 4.22 €/MWh in the *AC Only* scenario, 3.74 €/MWh in the *Stackelberg* scenario and 3.18 €/MWh in the *Fully Planned* scenario.

Concerning HVAC transmission, expansion costs in the different scenarios do not differ too much, the values deviate just up to 6% from their mean. Interestingly this small variation also holds for the structure of HVAC transmission investment: Most lines which are expanded in one scenario are expanded in other scenarios,

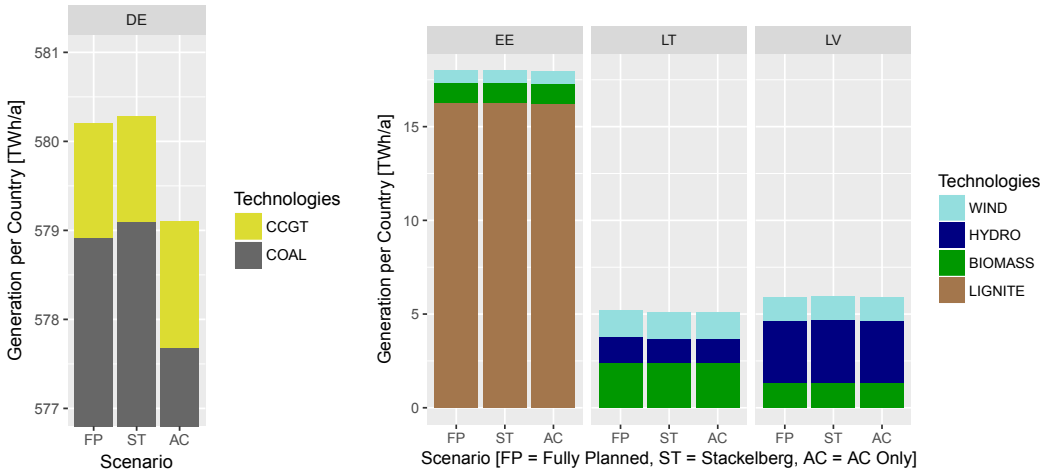


Figure 6.3.: Detailed representation of generation in Germany and the Baltic States. Source: Own calculations.

and respective expansion levels do not differ too much either, as shown in C.6. It can also be noted that overall transmission expansion is weak in the Baltic States, as are changes in generation (as discussed above). This is mainly due to the traditionally strong transmission grid in these countries. Polish, Finnish and Swedish networks are expanded on similar levels across the different scenarios. Finally, the German transmission system experiences the largest expansion in absolute terms. The transmission expansion pattern in Germany clearly indicates that maintaining the single bidding zone requires some transmission investment, as most reinforcements are made in a north-south direction.

As already indicated, HVDC transmission investment is highest in the *Fully Planned* scenario, while it is, by definition, absent in the *AC Only* scenario. The details of the HVDC investment decisions are provided in Table 6.4. Although a large set of options are provided to the merchant investor, his investment is just about one-third of the investment volume of the *Fully Planned* scenario. The only transmission investments made by the merchant are the Kontek Link and the Hansa Power Bridge, but with no less capacity than found in the *Fully Planned* scenario. Most remarkably, the LitPol interconnector would not be built in the *Stackelberg* Scenario, and an extension of the SwePol interconnector of roughly 700 MW would not be undertaken either. Further, in the *Stackelberg* scenario, it is interesting to observe that interconnection between exporters (Sweden, Denmark and Germany) is improved. This implies that price differences (reflecting heterogeneous generation opportunities) allow those countries to exploit their resources more efficiently.

To conclude these general observations, HVDC transmission investments do in our model, which takes into account (mostly) national bidding zones, mainly allow for

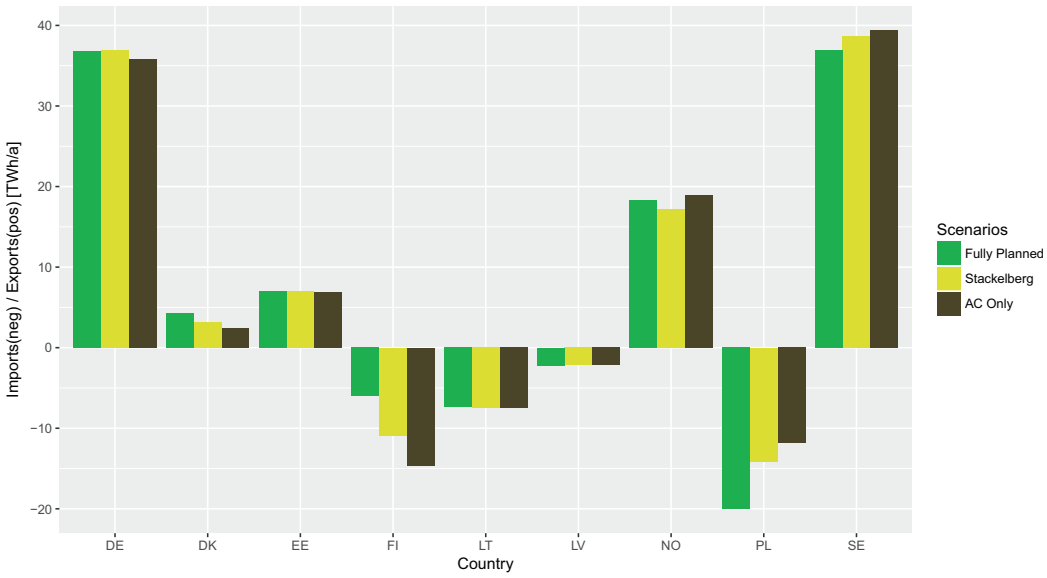


Figure 6.4.: Exports (positive) and imports (negative) of the Baltic Sea countries plus Norway. Source: Own calculations.

cost savings by replacing expensive coal (and to a very small extent, expensive gas) by cheaper coal.

6.5.2. Analyzing the merchant's impact (in the *stackelberg* scenario)

As shown before, the merchant's investment decision is only about one-third of the investment of the *Fully Planned* scenario. Still, the welfare contribution (as can be calculated from detailed costs and rent data, cf. Table 6.3) is quite fair: It amounts to 70.56% of the welfare increase that could be realized in the *Fully Planned* scenario. Yet, a detailed look at the rents accruing to the merchant shows that 96.03% of this welfare gain are pocketed by the merchant. This means that, in aggregate, all other actors only benefit by less than 4% from the welfare increase realized by the regulated transmission investment.

This is illustrated in Figure 6.5: While the maximum welfare increase of the *Fully Planned* scenario, as compared to the *AC Only* scenario, amounts to 58.4 € bn/a, the Stackelberg scenario leads to a welfare gain of 41.2 € bn/a (70.56%). However, a large share of this improvement, 39.6 € bn/a is pocketed by the merchant.

This result is somewhat counterintuitive as it puts the "underinvestment" criticism of merchant transmission into context. Reaching a welfare gain of about 70% of the theoretical optimum which is realized by investing a third of the money needed in the

Table 6.4.: Expansion of transmission lines in the *Stackelberg* and *Fully Planned* cases. For existing lines, only the additional expansion is given, no reduction of existing capacity was considered.

	Line	Line Expansion [MW] *Stackelberg*	*Fully Planned*
Existing HVDC Lines	DE-DK2 (Kontek)	500	403
	DE-SE4 (Baltic Cable)	-	-
	DK1-DK2 (Storebælt)	-	-
	DK1-SE3 (Konti-Skan)	-	121[a]
	FI-EE (Estlink I+II)	-	-
	FI-SE3 (Fenno-Skan)	-	-
	PL-SE4 (SwePol)	-	726
Candidate HVDC Lines	DE-SE4 (Hansa PowerBridge)	1,063	1,063
	EE-SE3	-	-
	FI-LV	-	314
	LT-PL (LitPol)	-	1,015
	LT-SE4 (NordBalt)	-	-
	LV-SE3 (Ambergate)	-	192[a]
Total HVDC Line Investment costs [mn €]		163.21	482.55

[a]These expansion decisions were neglected for the determination of the merchant's action space, because they are ≤ 250 MW, cf. Section 6.4.3.

Source: Own calculations.

optimum as "underinvestment," does not really hit the mark. Yet, more attention should probably be paid to distributional aspects.

6.5.3. Relaxing the stackelberg assumption

Although an analysis of more "competitive" merchant investment, taking into account sequential or simultaneous set-ups, or lack of perfect foresight, is beyond the scope of this chapter and requires complex assumptions, looking at the entire set of all 39,200 calculated HVDC investment alternatives allows for some insights into profit and welfare effects of investment choices diverging from the *Stackelberg* outcome.

To do so, we analyze the contribution to overall welfare and the change of the sum of producer, consumer, and regulated transmission rents of the potential investment choices analyzed against the *AC Only* and *Fully Planned* cases. As we collect our observations from the evaluations of the discretized merchant action space only, the *Fully Planned* benchmark used differs very slightly from *Stackelberg* benchmark as small investments (≤ 250 MW) are neglected (cf. Section 6.4.3).

First, in Figure 6.6 we plot the results of all 39,200 possible merchant investment combinations with respect to their welfare contribution, the merchant profit level and the DC line investment level (i.e. the direct transmission investment expenses

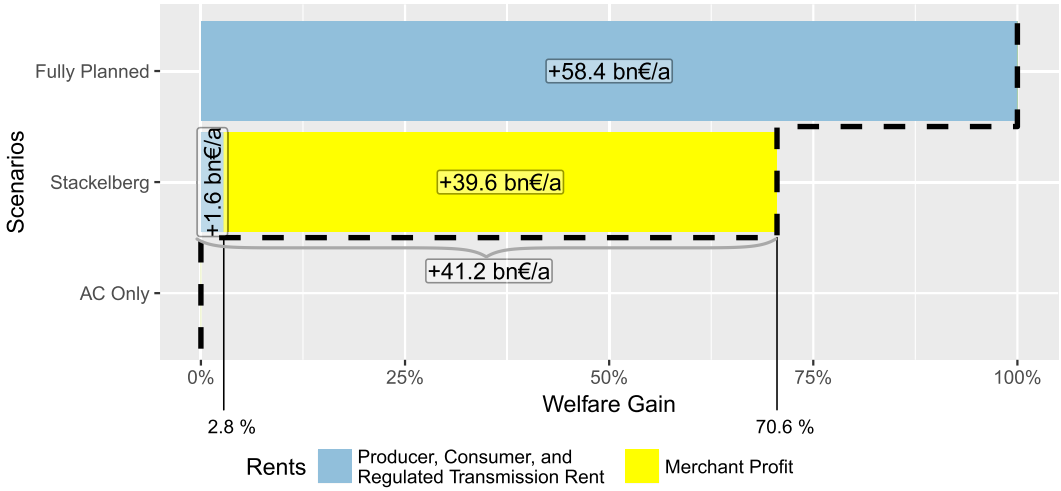


Figure 6.5.: Welfare differences and rents for all three scenarios. Source: Own Calculations.

incurred by the merchant). Unit merchant profit and unit welfare contribution are marked off on the X- and Y-axes (where *AC Only* $\widehat{=}$ 0 and *Fully Planned* $\widehat{=}$ 1). To improve clarity, the discrete investment choices are merged into tiles whose color indicate the average HVDC line investment level for the choices covered therein. In addition, the "hull" of the set of investment choices is roughly outlined by a bezier curve.

Three observations can be made:

- First, the bezier curve seems to support the results of the ideal *Stackelberg* scenario: The "bell" shape of the curve curve highlights that the "merchant" optimum, even with some variations, is close to a welfare contribution of ∼70%.
- Second, it is a priori plausible that competition may lead to deviations from this ∼70% welfare contribution level in either way.
- Third, profit maximization may induce investment choices where (roughly) the same amount of money is invested less efficiently (as indicated by the hardly changing colouring of adjacent tiles). This is interesting as it underlines that under-investment is not the only caveat regarding unregulated transmission investment: There may also be an incentive to invest inefficiently in terms of network structure, i.e. market prices (as modeled here) do not alone suffice to direct transmission investment to where it is most needed.

However, as with the *Stackelberg* cases, the more severe findings emerge from analyzing distributional aspects: In Figure 6.7 the diagram displays the unit changes

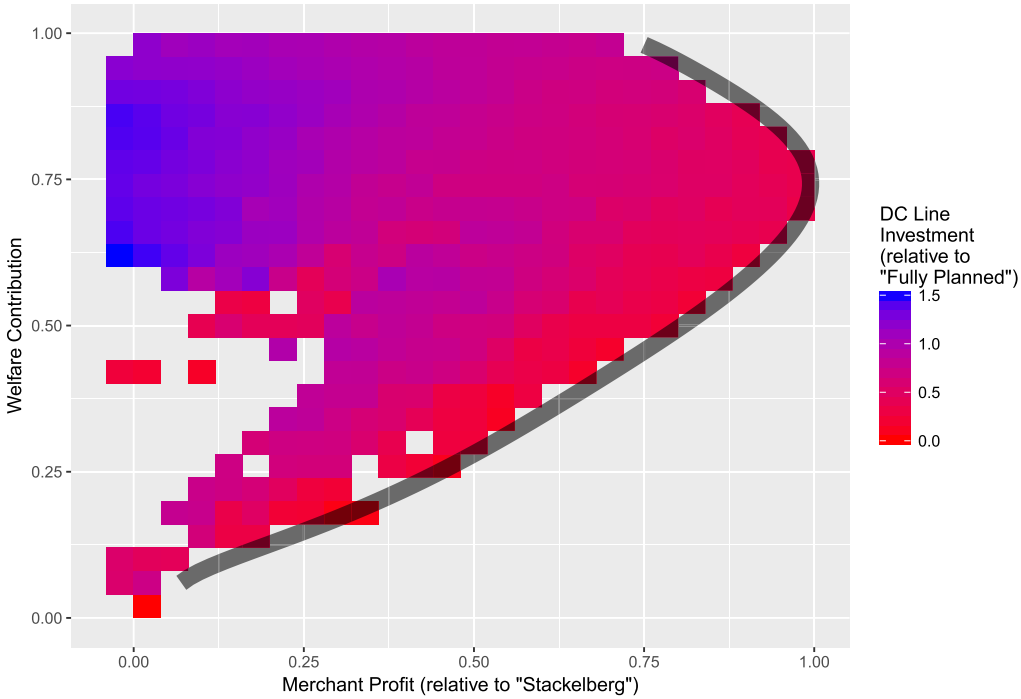


Figure 6.6.: Unit welfare contribution, unit merchant profit, and HVDC investment levels for different investment choices. Source: Own calculations

to producer, consumer, and regulated transmission rents, and unit merchant profit (again with *AC Only* $\widehat{=}$ 0 and *Fully Planned* $\widehat{=}$ 1). Again, the tiles are colored according to the average DC line investment levels of the choices contained therein. It can be seen that in many of the cases, which still represent profitable investment cases from a merchant perspective, the welfare gain that accrues to the group of any party except the merchant investor(s) is $\leq$50 % of the improvement delivered by the optimal, *Fully Planned* solution. In some cases, rents of generators, consumers and regulated transmissions are close the *AC Only* case: Then, those parties, in aggregate, do hardly experience any benefit from the new merchant transmission lines.

In addition, it can be observed that there seems to be a particular frontier indicating how generators, consumers, and regulated transmission welfare gains are limited for certain merchant profit levels: The bezier "hull" curve is the steeper, the higher the level of merchant profit is, indicating that the rate of appropriation of (producer, consumer and regulated transmission) rents by the merchant continously increases with his profit level.

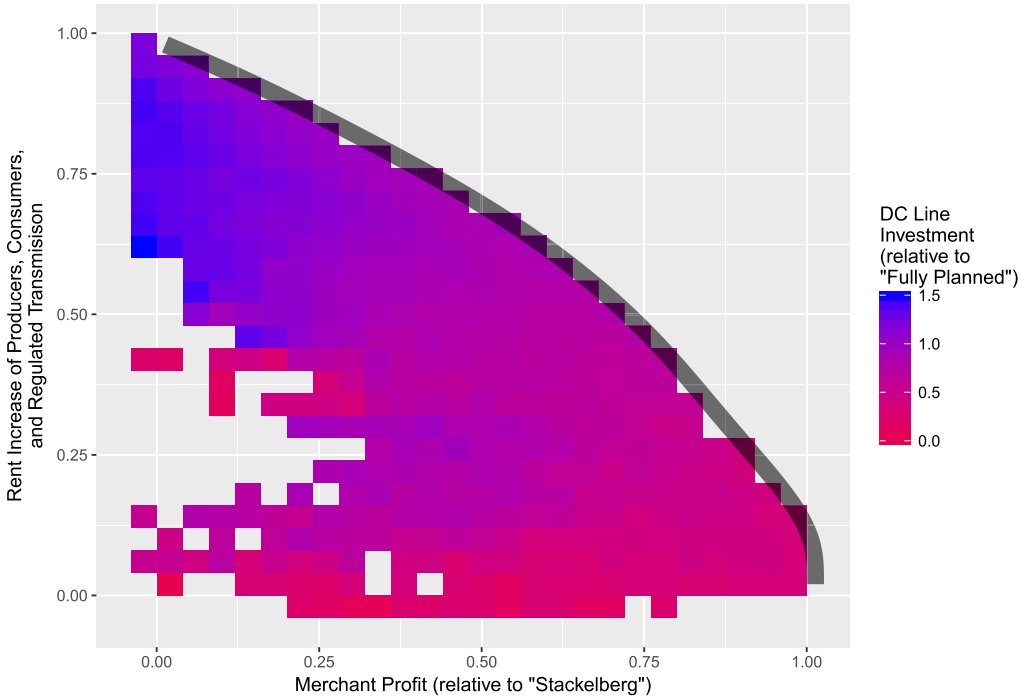


Figure 6.7.: Unit rent increase of generators+consumers and unit merchant profit for different investment choices. Source: Own calculations.

6.5.4. Remarks

The observations made in the previous section reinforce our findings from the "pure" *Stackelberg* scenario. In general, it needs to be stated that prices in a zonal set-up are distorted with respect to investments relating to specific system nodes as they react less quickly than (theoretically correct) nodal prices should. This, on the other hand allows for more merchant transmission expansion (in terms of welfare gain), but at the same time gives considerable revenue to the merchant investor. In our modelling, prices are marginals of the lower-level (regulator's) optimization problem. Therefore, they include a mark-up for internal (HVAC) transmission expansion. This means that prices which are calculated not taking into account internal transmission expansion can be supposed to react even more slowly to merchant investment decisions and may therefore reinforce the results obtained here.[62]

[62] This is consistent with simplified calculations made by the authors, determining the zonal price as the short-term variable of the most expensive power plant dispatched in that zone. Yet, this approach is incompatible with hydro-dominated systems and is not, for that reason, implemented here.

6.6. Conclusion

In our analysis, merchant investment can, from an overall welfare perspective, lead to surprisingly fair results: We obtain ∼70% welfare gain as compared to the ideal, *Fully Planned* case. This seems to hold also for cases where we relax the Stackelberg assumption. Thus, increased interconnection, also when delivered by a profit-maximizing merchant investor, seems to be favorable at first. However, we find evidence that profit maximization by the merchant may induce investment that is less efficient than other investments that could be realized at the same cost, i.e. the merchant's greed may (besides under-investment) lead to an investment that is inferior in terms of structure.

What may matter more is that the distributional effects of merchant transmission investment are quite severe: "The merchant takes it all" may, for some situations, be the correct diagnosis; "all" meaning (nearly) the overall welfare contribution generated by the merchant's investment choices.

Relating those findings to the arguments used in favor of allowing merchant investment, such as high technological risk and difficulties of different jurisdictions or actors to coordinate, implies that even if those arguments apply, merchant investment should be considered with extreme care, as the distributional consequences may – more or less – not be better than doing nothing at all.

More specifically, relating those findings to the recent developments of technology, governance and realized cross-border interconnector projects in Europe, it seems that little space is left for allowing merchant interconnectors to play any serious role: Technology (HVDC connections, often subsea) is more mature than it was in the 1990s, and it seems to be sufficiently well understood by both regulators and network companies. Additionally, the numerous DC-interconnector projects realized since the nineties, especially in the Baltic Sea region, are encouraging the belief that coordination problems between different jurisdictions can be overcome and are, thusly, not a valid problem. This is also supported by the successful (regulated) realization of the LitPol interconnector, which went operational in late 2015. Overall, this is also consistent with the increasing reluctance of the EC to approve merchant interconnector projects, as observed by Cuomo and Glachant (2012).

Concerning the potentially severe distributional effect of interconnector investment, the existence of inter-regulatory agreements, which do presumably also cover rent-sharing issues, gives some hope that regulators are able to cope with these aspects and that gains from trade can be distributed in accordance with political, i.e. societal, objectives. Even if, at the time, difficulties (such as documented by Makkonen et al. (2015) for the case of the Scandinavian countries) hinder inter-regulatory agreements, this does not unconditionally give way to merchant transmission investments: Given

that most of the gains will quite likely be pocketed by merchant investors (for ∼20–25 years), to strive for a political solution within 15 years clearly seems to be the better option.

Chapter 7

European electricity grid infrastructure expansion in a 2050 context

This article first appeared in The Energy Journal, Vol. 37, No. 1, pages 101–124, 2016 DOI: https://doi.org/10.5547/01956574.37.SI3.jege - Reproduced by permission of the International Association for Energy Economics (IAEE). Previous versions were published as DIW Berlin Discussion Paper No. 1299 (Egerer et al., 2013a) and presented at the 13th European IAEE Conference 2013 in Düsseldorf, Germany, the 10th International Conference on the European Energy Market (EEM 2013), and the 8th Annual Trans-Atlantic Infraday (TAI 2014) in Washington, USA.

7.1. Introduction

The transformation process of the European electricity sector has increasingly become more dynamic in recent years. From a European perspective, the main political drivers are the integration of national markets into one internal energy market (EC, 2008b, Article 194) and the reduction of total greenhouse gas (GHG) emissions. Compared to emission levels of 1990, general reduction targets are: i) the 20-20-20 goals, setting national emission reduction targets with an overall reduction of 20% in 2020 (EC, 2008a) and ii) the long- term reduction target as stated by the European Commission in the Energy Roadmap 2050 with a reduction of 80–95% by the middle of the century (EC, 2011a). In 2014, the European Commission has set a target of 40% for GHG reduction compared to 1990 with a renewable share of 27% for the European Union (EU) in 2030. The electricity sector plays a central role in the realization of these targets as its decarbonization is expected at a faster pace than that of the remaining economy.

On the contrary, energy policy remains a deeply national domain. National electricity systems historically rely on specific technologies and fuels in electricity supply for geographical and political reasons. It therefore comes as no surprise that the current transformation process varies strongly between individual member states. The national strategies and enthusiasm for the implementation of the 20-20-20 goals vary between member states in their design and ambition as do national renewable support schemes. In addition, there are different points of view on nuclear power and carbon capture, transport and storage (CCTS) as complementary options in a sustainable energy strategy. These challenges of combining national energy strategies and the vision of a European low-carbon electricity system with high renewable shares become apparent when raising the questions of market design and cross-border integration, with both depending on the physical exchange of electricity by the means of transmission infrastructure.

This chapter analyzes investments in the European high-voltage transmission network for different policy scenarios for electricity generation. A bottom-up electricity sector model assesses the cost-optimal network investments based on national generation portfolios which are disaggregated to a nodal representation of the electricity grid. The techno-economic mixed integer linear program (MILP) optimizes investments into voltage upgrades and line expansions in the existing high-voltage alternating current (HVAC) network and investments in additional point-to-point high-voltage direct current (HVDC) overlay lines in steps of ten years until 2050.

The analysis focuses on the effect of different policy scenarios for electricity supply with regards to i) the reduction of GHG emissions and ii) the technological preferences and their effect on the actual transmission investment needs using a European nodal

electricity sector model. The data for the pathways the power sector might take is based on PRIMES results with a national resolution, which have been created during the EMF 28 study (cf. Holz and von Hirschhausen, 2013; Weyant et al., 2013).[63] PRIMES has provided official numbers for the Energy Roadmap 2050 of the European Commission (EC, 2011a) and has thus undergone a stakeholder process in all member states of the EU. The scenarios in this chapter are the reference scenario, with a target of 40% GHG reduction by 2050 without technology restrictions (40%DEF), and two 80% mitigation scenarios. The first mitigation scenario sees no technology constraints (80%DEF) while the second scenario has higher renewable shares and technology constraints on CCTS and nuclear power(80%GREEN).

The combination of both national and European legislation affects the low-carbon transformation of the electricity system. In this context, top-down energy system models are a suitable tool to determine the least-cost system development for a set of physical, economical, and political scenario assumptions and constraints. While energy system models are capable of representing the entire energy sector, their complexity limits them to an analysis on a national level. Due to spatial aggregation and the resulting simplification of the network topology, energy system models provide limited insights into future infrastructure requirements. Several studies analyze the development of the European electricity system until 2050. Most studies, however, do not representthetransmission grid in detail but aggregate on a country level. (Capros et al., 2012; Dii, 2013; ECF, 2010; Eurelectric, 2011; Hagspiel et al., 2014)

The calculations for the European Union (EU) Energy Roadmap 2050 are based on results from the PRIMES model and describe possible pathways for the EU to reach its decarbonization targets while ensuring competitiveness and security of supply. For several scenarios, potential developments are analyzed in all energy-related sectors such as electricity, transportation, industry, and heating. The PRIMES model approximates the European transmission grid, using a single node per country and applies the direct current (DC) load flow linearization. Country nodes are interconnected by multiple cross-border lines with information (or assumptions, for new lines) on their thermal capacity and their line reactance. Investments in generation and transmission capacity are inter-temporally optimized under perfect foresight. The low spatial resolution of the aggregated transmission grid does not allow for transmission investment on national levels or line-specific N-1 security considerations.[64] The model scope is limited to the EU. Potential imports and

[63] The Stanford Energy Modeling Forum (EMF) employs an international expert group. The objective is to improve the understanding of energy and environmental problems by comparing modeling approaches and results (`https://emf.stanford.edu/`). The EMF 28 addressed the effects of technology choices on EU climate policy.

[64] N-1 Security (also called N-1 contingency) ensures that one element of the electricity grid can fail while leaving the system in a satisfactory state without causing any further failures such as line

exports from and to North Africa are not taken into account (EC, 2011a,c,f). In the results, expanding the capacity of the transmission grid is seen as a no-regrets option to be able to "accommodate various power generation pathways" (EC, 2011b, p. 14).

The Grid Study 2030/2050 by Tröster et al. (2011) determines a more detailed transmission grid expansion for Europe in the years 2030 and 2050, representing the European grid with 224 nodes. It implements the DC load flow linearization and approximates N-1 security with a limit of 80% of the thermal line flow capacity. Fürsch et al. (2013) use the same grid model with the addition of endogenous investments into power plants. This allows for a better trade-off between investments into generation, storage, or transmission lines.

The Ten-Year Network Development Plan (TYNDP) by the European Network of Transmission System Operators for Electricity (ENTSO-E) gives a detailed perspective on the planned grid expansions in Europe. These grid expansion plans are not solely based on model results but a combination of information provided by different institutions and stakeholders. Parts of the cost benefit analysis include the usage of power system models, including different levels of grid details (ENTSO-E, 2014c).

Compared to existing studies, this chapter implements a nodal resolution of the high-voltage transmission network allowing for a detailed spatial representation of load, generation, and electricity flows. The analysis of different exogenous scenarios for possible developments of national power plant portfolios disregards endogenous investment into generation capacity.

We find that transmission expansion can be seen as a no-regrets option in the short term, as significant cross-border expansion takes place in all modeled scenarios. Furthermore, the overall investment structure is comparable to the investments described in the TYNDP. In the long term until 2050, the scenarios with high GHG mitigation targets require substantially more investments than those with a moderate target. The overall interconnector investments of 30-60 bn€ by 2050 determined in this chapter are generally lower than those specified in the Energy Roadmap2050 (EC, 2011b). Even though the model allows for investments in an overlay HVDC grid, the majority of expansions take place in the existing HVAC network. By 2020, all scenarios suggest investments of about 16-19 bn€. Thereafter, only the high-mitigation scenarios require large additional network investments. The statement of transmission as a no-regrets option is valid until 2020 with market integration being the main driver. In this period, generation capacities are similar in all three scenarios due to the specific 20-20-20 targets. For the following decades, location and timing of transmission investments do not only depend on the GHG reduction target, but also on the choice of generation technologies. We find that the high-mitigation scenarios

overloading. If another element of the electricity grid fails, load shedding or similar actions must be performed to return to the satisfactory state.

are more robust against changes in interconnector investment cost. Without sufficient information on system development, particularly on the power plant portfolio, flexible infrastructure development might not be possible or might run the risk of stranded transmission investments.

The remainder of this chapter is structured as follows: the next Section 7.2 introduces to transmission investment decisions in electricity sector modeling and describes the methodology applied in this chapter. The data and scenarios are presented in Section 7.3. Section 7.4 discusses the quantitative results, and Section 7.5 provides the conclusion.

7.2. Mixed-integer transmission investment model

7.2.1. Introduction to modeling of transmission expansion planning

Models for transmission expansion planning in electricity networks have to consider many factors. They should include technical network aspects (e.g., flow distribution on lines, losses, and operational questions on network topology and reliability), investment options (e.g., lumpy investments, voltage levels, topology, and options for HVAC and HVDC technology), economic considerations (e.g., costs per investment option and power plant operation), uncertainty (e.g., development of load, generation capacity, and resource prices as well as short-term uncertainty in the system), and institutional and organizational aspects (e.g., market design, regulation, and cost-allocation). In the academic literature, publications focus on certain aspects of transmission expansion planning to reduce the model complexity and the size of the model scope.

The transmission expansion problem has not changed over time (cf. Kaltenbach et al., 1970), but today's computational power allows for an increase of model complexity and optimization using larger data sets. Latorre et al. (2003) provide an overview of models and important aspects on transmission expansion planning. Still, from a modeling perspective, the planning problem has certain particularities that require non-linear constraints or integer variables. The most important ones are the representation of quadratic losses in electricity transmission, lumpy line investments in voltage upgrades and additional line circuits, new lines between previously unconnected nodes changing the topology, and the bi-linearity between endogenous variables for physical line parameters and for load flow. Including some of these important aspects into the optimization models drastically increases computation time and complicates the convergence to the global optimum compared to a linear optimization model. Different approaches to modeling transmission expansion plan-

ning can be found in Alguacil et al. (2003), Bahiense et al. (2001), Gunkel and Möst (2014), Lumbreras et al. (2014), Tejada et al. (2015), and de la Torre et al. (2008).

7.2.2. Mathematical formulation of the extended ELMOD model

The model application in this chapter is an extension of ELMOD, a techno-economic model developed at the Dresden University of Technology (Chair of Energy Economics), the Berlin University of Technology (Workgroup for Infrastructure Policy), and the German Institute for Economic Research (DIW Berlin, Department of Energy, Transportation, Environment), see Leuthold et al. 2012. ELMOD is a large-scale spatial model of the European electricity market including both generation and the physical transmission network.[65] In this analysis, the model application is on infrastructure investments into the European high-voltage transmission system until 2050. Section 7.2.3 provides a critical discussion of model assumptions and limitations.

The model optimizes line investments for specific years. A rolling planning approach is used, so that the optimization is conducted consecutively for each decade, building on the results of the previous optimizations. The initial network for one year includes the initial network topology and all additional investments for the previous periods. The model has two decision levels, one for transmission investments and the other for generation dispatch. The assumption of perfect competition with a European central planner expanding the transmission network with the aim of minimizing total system costs reduces the two decision levels to one objective value. The total system costs in the objective function (7.1) include annualized costs of network investments (variables ul_l are for an HVAC upgrade, el_l for additional HVAC lines, and ed_l for additional HVDC lines) and variable generation costs of the generation $g_{n,s,t}$ (i.e., costs for fuel and carbon emissions) for a set of hours, which are scaled to one year (with the factor Y). Capital cost of existing infrastructure and for power plants is not taken into account. The model is a MILP to account for the lumpy nature of transmission investments. Investments are either represented with binary variables for upgrade decisions to a higher voltage level or with integer variables for additional lines. The applied methodology does not include combined investments in generation and transmission, as the generation capacities are exogenous parameters provided by the results of an energy system model.

[65] ELMOD has been adjusted for various research questions: e.g. for market design (Weigt et al., 2010), for uncertainty and stochastic effects (Abrell and Kunz, 2015), for welfare distribution (Egerer et al., 2013b), for regulatory challenges (Egerer et al., 2015b; Rosellón and Weigt, 2011), and for integrated planning of the electricity system with investments in generation, storage, and transmission for the integration of renewable generation (Egerer and Schill, 2014).

The model approximates the characteristics of power flows in meshed networks for the HVAC grid, following the DC load flow approach of Schweppe et al. 1988. In the typically meshed HVAC grids, the flow on a specific line cannot be controlled directly due to the existence of loop-flows. Line flows depend on all power injections and withdrawals at network nodes as well as the technical and topological configuration of all elements in the HVAC grid. This characteristic is represented with the linearized DC load flow approach which, however, neglects some technical grid characteristics such as reactive power.

HVDC lines are assumed to be point-to-point lines without meshed elements and implemented with transport flows in the model. Therefore, their operation is not part of the DC load flow approach. It can be determined freely within the given technical limits. The approach mimics modern HVDC connections where the operator is relatively free in deciding how much power to transfer.

Operation of the transmission grid must not be critically endangered by the failure of any one component, so-called N-1 security. This aspect is approximated in the expansion model by a reduction (transmission reliability margin) of the maximal power flow limit for every transmission line. An endogenous consideration of individual line failures to represent N-1 contingency is not possible due to the additional model complexity and the network size in the application (see Section 7.2.3 for a discussion).

$$\begin{aligned} \min cost = & \sum_{n,s,t} (g_{n,s,t}\hat{C}_{n,s})Y + \sum_{l} (ul_l CUL_l + el_l CEL_l) \\ & + \sum_{d} (ed_d CED_d) + \sum_{n,t} ens_{n,t} VOLL \end{aligned} \tag{7.1}$$

In addition to the objective function for a specific year (7.1), which minimizes the combination of annual variable generation costs and annualized investment costs in the HVAC and HVDC network, (7.2) to (7.12) describe the constraints of the model. The nodal energy balance (7.2) ensures that load is $Q_{n,t}$ equal to supply in all nodes and hours. Combined nodal generation output of all conventional ($g_{n,s,t}$) and renewable ($r_{n,t}$) technologies plus in- and outflows on HVAC lines ($nil_{n,t}$) and HVDC lines ($nid_{n,t}$) determine nodal supply. Energy not served ($ens_{n,t}$) will be priced the value of lost load ($VOLL$) in the cost balance.

$$\sum_{s} g_{n,s,t} + r_{n,t} + nil_{n,t} + nid_{n,t} + ens_{n,t} = Q_{n,t} \qquad \forall n, t \tag{7.2}$$

Equation (7.3) limits conventional generation output per technology in each node to the installed capacity $G_{n,s}$. A similar time-dependent constraint exists for all renewable generation per node with Equation (7.4).

$$g_{n,s,t} \leq \overline{G}_{n,s} \qquad \forall n, s, t \tag{7.3}$$

$$r_{n,t} \leq \overline{R}_{n,t} \qquad \forall n, t \tag{7.4}$$

The flow on HVAC lines is restricted by the constraints (7.5)–(7.6) of the linearized DC load flow approximation (Schweppe et al., 1988) and by the transmission capacity of each HVAC line in Equation (7.10). Point-to-point HVDC lines are implemented with directed flows ($pd_{d,t}$) in (7.11) that are only constrained by capacity in Equation (7.12). Equation (7.5) determines the inflow or outflow for each node and hour depending on the phase angle $\theta_{n,t}$ and network susceptance matrix $B_{n,i}$. The power flow $pl_{l,t}$ on each HVAC line is determined in equation (7.6) dependent on phase angle and network sensitivity matrix $H_{l,n}$. As only the difference of phase angles is relevant in the determination of power flows, the phase angle is fixed to zero at one node (the slack bus, SB_n) in each of the non-synchronized HVAC networks (7.7). Equations (7.8) and (7.9) describe the calculation of the network sensitivity matrix $H_{l,n}$ network susceptance matrix $B_{n,i}$ based on the series susceptance (BL_l) of the HVAC lines.

$$nil_{n,t} = \sum_i (B_{n,i}\theta_{n,t}) \qquad \forall n, t \tag{7.5}$$

$$pl_{l,t} = \sum_n (H_{l,n}\theta_{n,t}) \qquad \forall l, t \tag{7.6}$$

$$\theta_{n,t}SB_n = 0 \qquad \forall n, t \tag{7.7}$$

$$H_{l,n} = BL_l IML_{l,n} \qquad \forall n, l \tag{7.8}$$

$$B_{n,i} = \sum_l (IML_{l,n}H_{l,i}) \qquad \forall n, i \tag{7.9}$$

$$|pl_{l,t}| \leq \overline{PL}_{l,t} + ul_l PUL_l + el_l PEL_l \qquad \forall l, t \tag{7.10}$$

$$nid_{n,t} = \sum_d (pd_{d,t}IMD_{d,n}) \qquad \forall n, t \tag{7.11}$$

$$|pd_{d,t}| \leq \overline{PD}_{d,t} + ed_d PED_d \qquad \forall d, t \tag{7.12}$$

The main driver of infrastructure investment is the regional level of load in relation to the spatial availability and variable cost of generation. In the case of network congestion, it is not possible to operate the electricity system with the least-cost generation capacities. In this case, an incentive to invest in transmission capacity

emerges. The imposed deviations from the least-cost merit order dispatch provide incentives to invest in transmission. The model allows for upgrades of lines with lower voltage levels than the common voltage level of 380 kV in Europe. For upgraded lines and those already operated at 380 kV, the model can invest in additional circuits of 380 kV, thereby maintaining the topology of the high-voltage transmission network. A second option is investment in a set of predefined point-to-point HVDC connectors. Investment into transmission relaxes the constraints of equations (7.10) and HVDC (7.12) for line flows and can relieve congestion, allowing for a generation dispatch with lower variable generation cost. An overall reduction in system cost is reached if the cost savings in the power plant dispatch are higher than the equivalent annuity for the line investment.

Investments in the HVAC transmission system affect the series susceptance (BL_l) of lines and thereby change the flow pattern in the meshed HVAC network. An endogenous consideration of changing flow patterns in the DC load flow implementation requires bi-linear terms in the model constraints. $B_{n,i}$ or $H_{l,n}$, which are multiplied with $\theta_{n,t}$, would become variables when considering the changing values of BL_l as a result of line extension. To remain in a linear model world, the applied linear model is solved iteratively for investment in transmission capacity, at first neglecting changes in BL_l and in the flow patterns (see Figure 7.1). After each optimization, the $B_{n,i}$ and $H_{l,n}$ matrices are updated with the new series susceptances (BL_l) to represent the new network configuration after the optimization. Before starting the next iteration, the model is run using the new lines and updated flow patterns but without additional network investments to calculate the system costs of the respective network configuration. Then the optimization is repeated in the next iteration whereas line investment of the previous iterations can be undone by reimbursing the investment costs. These steps are repeated until either i) the resulting grid expansion does not change between iterations anymore, or ii) identical configurations are observed twice, which indicates that the optimization enters a loop of repeating solutions. In both cases the grid configuration of all iterations with minimal total cost is used as the final solution.

This heuristic approach does not guarantee global optimality of the grid expansion configuration, but provides a very good approximation. During model development, this approach has been compared to a global search with aforementioned bi-linearities on small and medium-sized problems. Here, the results were either globally optimal, or the differences were relatively minor. The iterative optimization process reaches convergence for the conducted model runs after about ten iterations.

Each optimization period accounts for ten years, using a rolling planning approach. The model optimizes the network topology consecutively for 2020, 2030, 2040, and 2050, corresponding to the data provided. The result for one period is the initial

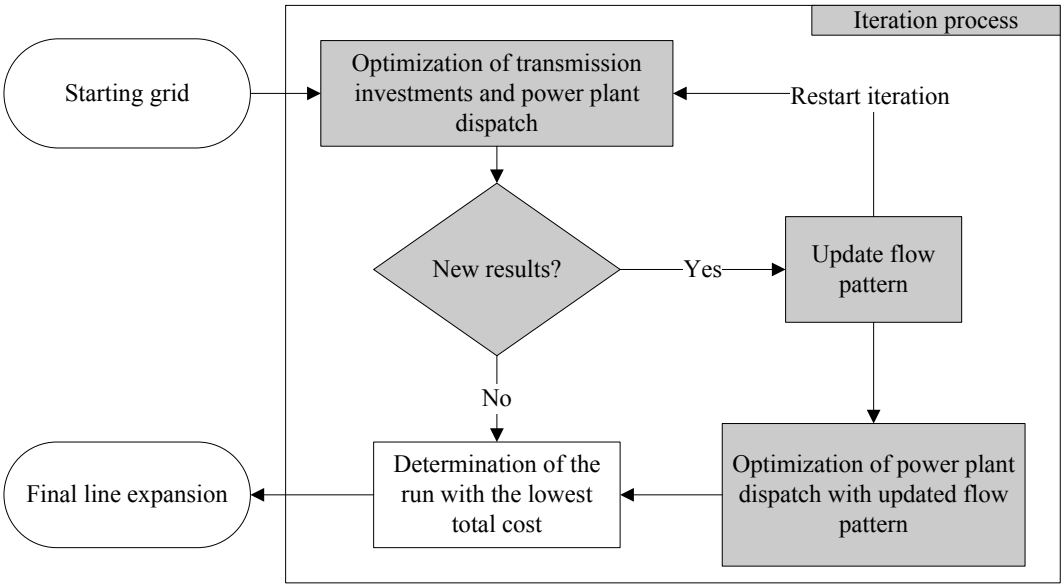


Figure 7.1.: Optimization process. Source: Own depiction.

network configuration for the subsequent period. The size of the network and the number of hours require a limitation of the number of binary and integer variables before optimizing the entire model scope. This is done by solving the model for each single model hour separately. Every upgrade and expansion occurring in any of these separate runs remains in the solution space for the optimization with all model hours. This approach limits the model to only a certain set of available expansions. Its results have been compared to those of full enumeration for smaller problems. Here, the preselection using the reduced problems has provided a very good selection for the problem with all hours. Therefore, it can be expected that the preselection is no significant distortion for the results of the bigger problem.

The model has been formulated in GAMS and can be solved using CPLEX on a workstation with 8 cores and 2.5 GHz and 16 GB of memory within twelve hours for one year.

7.2.3. Critical discussion of model assumptions and limitations

The network investment model has several main characteristics: i) the nodal network representation of the high-voltage transmission network, ii) the integer formulation for line investment of different type and technology, iii) the iterative optimization process for line investment to address changing flow patterns in the DC load flow linearization, and iv) the cost-minimizing formulation of the generation dispatch. Therefore, the approach allows for a cost-minimizing optimization of all line investments in the

electricity system. The model is applied to the European transmission network and has a large number of integer variables (i.e., one binary variable per possible voltage upgrade, an integer variable per HVAC line, and an integer variable per HVDC line). Size and complexity of the model require the following model limitations which have to be regarded in the evaluation of the results.

In the generation dispatch, the model applies the same aggregation of generation technologies as the input data of PRIMES does. It abstracts from individual power plants by aggregating data on generation units to generation technologies at network nodes. Also, the temporal representation is limited to a small set of system states (i.e., load levels and availability of renewable energy sources). These limitations reduce the model complexity but do not allow for a detailed implementation of system stability in extreme conditions, inter-temporal constraints, and system flexibility, all being important aspects for renewable integration. However, network investment is only one option among several others to handle system transformation and the integration of renewables.

The limitations mostly suggest that the model results provide a lower bound for network investment. However, a more detailed implementation of the possible development of significant storage capacity or increased utilization of demand response could reduce the level of network investment.

In the network representation, the DC load flow linearization determines a flow distribution according to the network topology and physical line characteristics. The applied methodology takes changes of flow distributions into account which result from investments in HVAC lines. This is not done during the optimization itself, but in consecutive iterations of the iterative optimization process. An endogenous implementation in a single optimization would require non-linear model constraints.

Additional limitations of the expansion model are the preselection of HVAC investment options by model runs of every individual hour, the limitation of HVDC investment to a set of candidate lines, and the separate optimization for every ten years. The preselection of HVAC investment options might only lead to a locally optimal investment combination, as only the computation of the full model analyzes the interactions of all model hours. Lumbreras et al. (2014) suggest an automatic preselection of candidates for line expansion using benders decomposition, which allows for keeping the globally optimal combination in the solution space. The preselection algorithm used in this chapter provides an efficient combination between computational complexities and finding optimal solutions.

Restricting the set of available HVDC connections to 23 connections allows for a computationally more efficient implementation compared to a highly meshed HVDC candidate grid. This simplification possibly underestimates the benefits of HVDC lines and leads to less HVDC and more HVAC investment.

The consideration of line losses could make HVDC lines more attractive as an option for long-distance transportation. The trade-off between HVAC and HVDC technology is also sensitive to cost parameters for investment.

Last but not least, to keep the model calculations tractable, the model uses a transmission reliability margin of 20% for HVAC and HVDC lines. A detailed representation of N-1 contingency remains challenging in optimization models on transmission expansion planning for large networks. Using the reliability margin affects the results in several ways. HVAC lines are usually well interconnected. Here, the assumption of a reliability margin is more adequate for most lines, as a contingency can usually be accommodated by the surrounding grid. Following this argumentation, the reliability margin for HVDC lines would have to be higher as a contingency would lead to a steep decrease in transmission capacity along the HVDC corridor.

The model limitations indicate the focus on cost-minimizing network optimization for different generation scenarios. The methodology applies a stylized representation of system security in the optimization as it does not explicitly model N-1 contingency and other stability criteria. A detailed N-1 consideration for every line is likely to result in additional investments in transmission lines. While a higher temporal resolution of system states could also increase transmission investment, the opposite effect could be expected by the inclusion of local line-specific cost factors for all lines such as additional external costs.

7.3. Data and scenarios

7.3.1. Initial system data

The network topology consists of four non-synchronized high-voltage electricity grids (Central Europe, Scandinavia, Great Britain, and Ireland) with the voltage levels 150 kV, 220 kV, 300 kV, and 380 kV. Twelve HVDC cables connect these systems. The grid has a total of 3,523 nodes (substations) and 5,145 lines as shown in Figure 7.2.[66]

Each HVAC line is defined by the starting and ending node, its length, voltage level, and the number of installed circuits. Endogenous investment decisions include a binary decision for the voltage upgrade of lines to 380 kV and an integer decision for 380 kV lines to increase its number of circuits.

THVDC lines are defined by a starting and an ending node, capacity, and length. The twelve existing HVDC lines are ten offshore connectors between the non-synchronized networks of Ireland, Great Britain, Scandinavia, and continental Europe, one cable between Greece and Italy, and one between Finland and Sweden. For invest-

[66] Information on the ELMOD model is available on the DIW Berlin website `www.diw.de/elmod`. Egerer et al. (2014) describe the European dataset of the ELMOD model in detail.

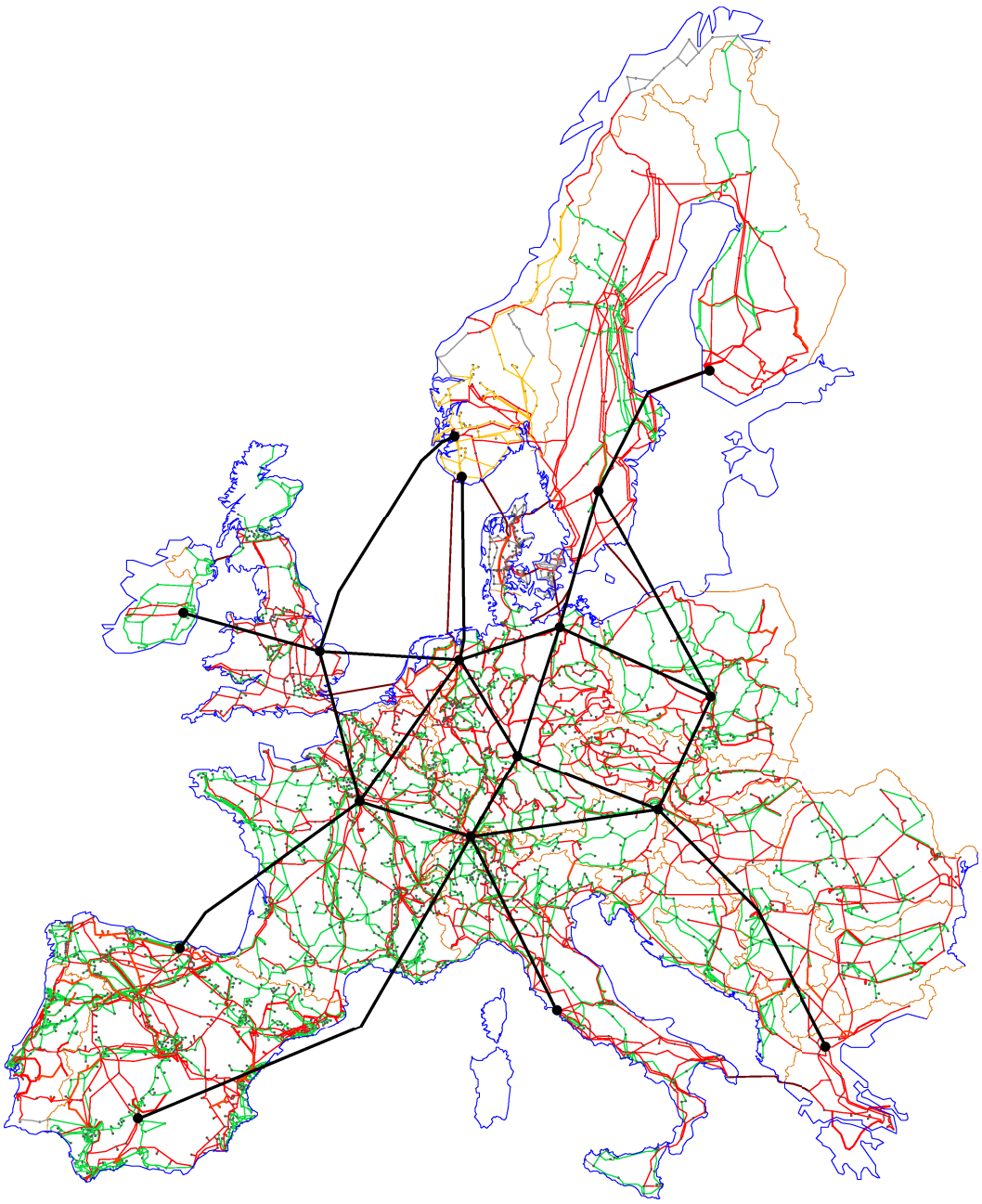


Figure 7.2.: Initial network topology for Europe and HVDC overlay grid. Source: Own depiction.

Table 7.1.: Parameters for transmission investment

in mn €	Transformer stations	Cost for one kilometer	Nominal Capacity in MW
HVAC expansion (per additional circuit)	4.0	1.4	1700
HVAC upgrade (per upgrade to 380 kV using the same towers)	6.5	0.2	1700
HVDC line (per circuit)	260	1.4	2000

Source: 50Hertz et al. (2012, p. 384). Annualized costs are calculated using costs given above and an assumption on the lifetime (40 years) and an interest rate (8%)

ments in additional HVDC lines, the model only has the option to invest in lines of an overlay HVDC backbone grid, as outlined in Figure 7.2. The additional HVDC lines are exogenous options, which include 23 individual point-to-point connections all over Europe. These network nodes have been chosen based on good interconnection in the HVAC network and distance to load/generation centers, where an HVDC endpoint could likely be built.

Investment costs in Table 7.1 are calculated for each individual line with regard to the technology and the type of investment. They include investment costs for two transformer stations per line and a cost factor for every kilometer of the transmission line. Transformer stations are more expensive for upgrades than for expansion, as additional transformers from 380 kV to 110/220 kV will become necessary.

The spatial character of the model requires nodal shares for load and generation in each country. National load is spatially distributed based on the population of NUTS regions.[67] The spatial distribution of conventional generation capacity is based on the PLATTS power plant database.[68] Its power plants (including hydropower and biomass) have been geocoded and, aggregated by technology, are allocated to the closest network node in the same country. The allocation of the national renewable capacity (i.e. onshore wind, photovoltaic (PV), and concentrated solar power (CSP)), to the nodes in the network uses a combination of the technical potential and the size of the NUTS 2 zones.[69][70] For each country the national share of the NUTS 2

[67] Load is allocated corresponding to network nodes on NUTS 2 level. The Nomenclature des unités territoriales statistiques (NUTS) is a geocode standard by the European Union for statistical purposes. European Commission (2012): Eurostat Statistics Database. `http://ec.europa.eu/eurostat/web/main/home`.

[68] Platts (2011): World Electric Power Plants Database. `http://www.platts.com/products/world-electric-power-plants-database`

[69] ibid. European Commission (2012).

[70] Average wind speeds for onshore wind and the average radiation for PV/CSP are provided on NUTS 2 level based on ESPON (2009): ReRisk – Regions at Risk of Energy Poverty, Tech. rep., ESPON, Luxembourg.

zone's potential is determined and allocated evenly to all nodes within the respective zone. Nodal data for national offshore wind allocation reflects spatial information for the projection of future offshore wind capacities.[71]

To account for the fluctuating characteristics of load and renewable energy sources, 18 model hours are generated. These hours describe two seasons (summer and winter), three times of the day (day, night, and shoulder hours), and three wind availability cases (high, mid, and low) as shown in Table 7.2. Different load factors are calculated for summer and winter as well as for day, night, and shoulder hours by an aggregation of national hourly load data for 2012.[72]

Table 7.2.: Reference hours.

Season	Summer									Winter								
Solar availability, load	Day			Night			Shoulder			Day			Night			Shoulder		
Wind availability	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18

Source: Own assumptions.

For PV and CSP, 70% of the annual electricity generation is assumed to be generated in the summer and 30% during winter hours, which is further allocated to day and shoulder hours (Table 7.3). Due to shorter time with daylight, shoulder hours in the winter have a lower share than in the summer. For wind power, different shares between winter and summer are calculated for each country based on monthly electricity output levels. The allocation on high, mid, and low wind hours (Table 7.4) assumes more balanced generation levels for the winter than for the summer and for offshore wind compared to onshore wind. The factors do not distinguish between day, night, and shoulder hours.[73] Pumped storage and reservoirs are modeled as run-of-river power plants with correspondingly adjusted availabilities.

7.3.2. Scenarios on the development of the electricity sector

In the analysis, the results of three EMF 28 scenarios (Weyant et al., 2013) serve as input for the transmission investment model. The scenarios are distinguished by the two dimensions "policy" and "technology". The policy measures define a certain

[71] OffshoreGrid (2011): Offshore grid: Deliverable 3.1 – inventory list of possible wind farm locations with installed capacity for the 2020 and 2030 scenarios. `http://www.offshoregrid.eu/index.php/results`

[72] ENTSO-E (2012): ENTSO-E Consumption Data. `https://www.entsoe.eu/data/data-portal/consumption/`

[73] The limited number of hours in the model only allows the representation of basic effects in the fluctuating generation pattern of solar and wind technologies. They include seasonal and daytime patterns for solar and seasonal and three output levels for wind. Therefore, the 18 hours allow for some temporal differentiation. The spatial correlations of wind and solar generation levels are neglected in the data.

Table 7.3.: Solar production energy share.

Summer (70%)			Winter (30%)		
Day	Night	Shoulder	Day	Night	Shoulder
71%	0%	29%	83%	0%	17%

Source: Own assumptions.

Table 7.4.: Wind production energy share.

	Summer			Winter		
	High	Mid	Low	High	Mid	Low
Onshore	70%	25%	5%	65%	25%	10%
Offshore	60%	30%	10%	55%	30%	15%

Source: Own assumptions.

mitigation level for GHG emission. The constraints on the availability of certain generation technologies depict different developments in the power plant portfolio. All three scenarios fulfill the 20% emission reduction target for Europe by 2020:

- The 40%DEF scenario without progressive climate policy represents the reference scenario. No technology restrictions exist. CCTS technology for fossil power plants, nuclear power, renewable energy sources, and energy efficiency follow a reference pathway leading to a GHG reduction of 40% by 2050.

The other two scenarios assume a more progressive climate policy in Europe leading to a mitigation level of 80% by 2050:

- The 80%DEF scenario sets no constraints on the use of nuclear power and CCTS technology. Hence it uses the same technology constraints as the 40%DEF scenario. It allows for a comparison of the additional infrastructure needs assuming progressive policy compared to the reference scenario.

- In contrast, the 80%GREEN scenario constrains the usage of nuclear power and CCTS technology by technological availability as well as slightly increased fuel prices. While assuming a higher level for energy efficiency, renewable energy sources (RES) capacities deliver most of the additional GHG reduction on the generation side. The electricity demand development is generally slightly lower, with a total demand in 2050 of 94% compared to the 80%DEF scenario. The comparison between the scenarios 80%DEF and 80%GREEN highlights the effect of technology choices on infrastructure requirements.

The top-down energy system models provide their results on a national level for the different policy scenarios. Input data for the infrastructure model is derived from

results provided by the PRIMES model (cf. Capros et al., 1998; EC, 2011a) This includes data on generation capacity, annual demand, annual renewable generation output, resource prices for gas and coal, and the carbon dioxide (CO_2) emission price. Figure 7.3 shows the aggregated generation capacities for all countries in the different scenarios.[74]

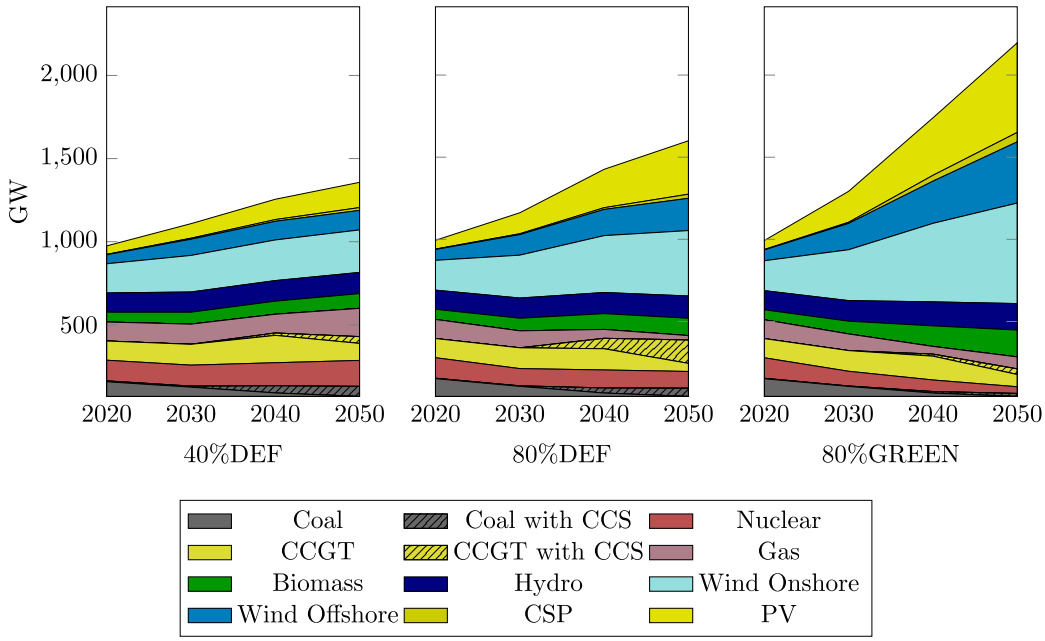


Figure 7.3.: Aggregated PRIMES results for the development of the European generation capacity, 2020-2050. Source: Own depiction based on PRIMES.

The initial nodal generation capacities of the model data set are scaled to fit the national PRIMES data for each scenario and year. Assuming a brownfield approach for generation investment, the spatial distribution of generation capacity per technology does not change within one country over time. As the PRIMES output is only reported for EU27 countries, the power plant capacity of the PLATTS database is used for Croatia and non-EU27 countries (Switzerland, Norway, and non-EU countries in south-eastern Europe). For these countries, demand remains constant and only minor changes are assumed in the installed generation capacity over time. In Switzerland, existing nuclear generation capacity is decommissioned and replaced by combined cycle gas turbine plants by 2040. The installed hydro capacity in Norway increases by 10% by 2050.

[74] Due to contractual restrictions, the results of the PRIMES model cannot be stated on a national level. The data section is limited to an aggregated overview for key scenario data on European level and the description of the regionalization of the national PRIMES data.

7.3.3. Regional character of the scenarios

The scenarios presented in the section above not only differ in the total amount of installed generation capacities, but also in the distribution of these capacities among the countries.Therefore, the scenarios can also be characterized by their regional character and how robust the scenarios are concerning changes in transmission pricing.

In a transmission investments model, the point of minimal total cost does not represent the case of a congestion-free network in all periods, but a point where the cost of grid congestion (e.g., the constraints) and the investment cost into the grid are even (Kirschen and Strbac, 2004). Therefore, optimal infrastructure includes temporary congestion. Transmission investment costs can be a low-cost option compared to generation investments. If costs for transmission infrastructure were higher, the point of optimal transmission investments would include fewer investments in transmission and include higher generation cost.

Building on Midwest ISO (2010, p. 30), we assume that national generation scenarios are more price-sensitive regarding the transmission investments than European scenarios. To test the sensitivity of this regional case we double the cost of cross-border investments and compare the results to the European case. The changes in line expansions in kilometers indicate the scenario's robustness and price-sensitivity.

7.4. Results

The results section first, in Section 7.4.1, describes which lines are upgraded or built by the model, in physical terms, for example, HVAC or HVDC (in GW), and then, in Section 7.4.2, translates these physical investments into monetary terms (in EUR); we also look at the dynamics of network expansion over time. The following Section 7.4.3 characterizes the scenarios regarding their regional or European characteristics. Subsequently, Section 7.4.4 compares the results to other studies and those of the Energy Roadmap 2050 by the European Commission.

7.4.1. Transmission expansion in AC and DC technology

Tables 7.5 and 7.8 summarize the results of the model for the physical expansion of the network, differentiated by technology, i.e. AC and DC, as well as differentiated by time step and domestic vs. cross-border lines. Table 7.5 reveals an interesting finding that is often ignored in aggregate analysis: domestic upgrades play an important role in all scenarios, and outweigh cross-border investments by large (over 2:1 in the 40%DEF scenario, and over 3.5:1 in the 80% scenarios). The total number of kilometers increases between the 40% scenario (27,978 km) and the 80% scenarios,

but is almost identical within the 80% scenarios; it is even slightly lower in the 80%GREEN scenario (50,993 km) than in the 80%DEF scenario (52,424 km). The two 80% scenarios differ; however, with respect to their distribution between HVDC and HVAC cross-border lines, as the 80%GREEN scenario has a higher share of HVDC cross-border lines.

Table 7.5.: Kilometers per line type.

in km	DC Cross-Border	AC Cross-Border	AC National	Total
40%DEF	4,174	4,611	19,194	27,978
80%DEF	5,346	7,173	39,905	52,424
80%GREEN	7,057	4,138	39,798	50,993

Source: Own calculations.

Table 7.6 provides details of the dynamic transmission expansion process by decade. Unsurprisingly, the level of network expansion is related directly to the generation investment in the underlying PRIMES-scenario. Therefore, in the 40%DEF scenario, most transmission expansion occurs until 2020, and very little in 2020 to 2030. On the contrary, the expansion path in the 80%DEF scenario lies mainly in the 2030 to 2040 period, whereas in the 80%GREEN scenario it is in the 2040 to 2050 period, because the model suggests to achieve the 80% CO_2-reduction target only at a later stage. A look at the spatial distribution of the transmission investments confirms that the largest share is related to domestic lines, and that HVAC expansion clearly dominates the HVDC grid expansion.

Table 7.6.: Total kilometers of upgrades or expansion.

in km	Technology	2020	2030	2040	2050	Total
40%DEF	AC	14,908	175	3,644	5,078	23,804
	DC	2,770	939	0	465	4,174
	Total	17,677	1,113	3,644	5,543	27,978
80%DEF	AC	15,036	2,443	17,510	12,090	47,078
	DC	3,629	472	778	467	5,346
	Total	18,665	2,915	18,288	12,556	52,424
80%GREEN	AC	12,802	2,804	8,216	20,114	43,936
	DC	3,629	1,250	1,245	933	7,057
	Total	16,431	4,054	9,461	21,048	50,993

Source: Own calculations.

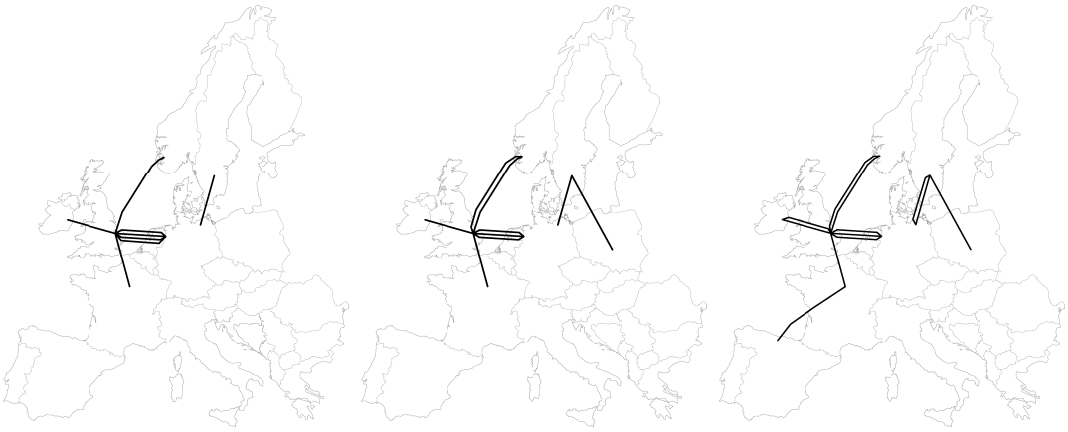
In the 40%DEF scenario, mainly local grid reinforcement measures are necessary with a focus on cross-border connections and the network development in Central-Eastern Europe (Figure 7.4). The 80%DEF and 80%GREEN scenarios invest slightly more in cross-border lines (+3,700 km/+2,400 km) and significantly more in the AC

network within countries (+20,700 km/+20,600 km) than the 40%DEF scenario. In the 80%GREEN scenario, the higher renewable share results in higher DC cross-border investments in the North and Baltic Seas region and additional AC lines as integration measures at the connection nodes of the DC lines with the AC network (e.g. in Sweden, France, and Germany). On the contrary, the solar capacities in Southern Europe do not seem to generate a corresponding level of DC connections in Southern Europe. The 80%DEF scenario also requires some of the investments for the integration of increasing renewable generation. Yet, the renewable share is lower than in the 80%GREEN scenario as the scenarios allows for more CCTS technology and an overall constant level of nuclear power in the European electricity system. This combination of a lower renewable share and a shift in the spatial allocation of nuclear and coal power plants results in less investments in the North and Baltic Seas region and a more dynamic network development in Central-Eastern Europe.

(a) 40%DEF (b) 80%DEF (c) 80%GREEN

Figure 7.4.: AC grid infrastructure investments. Source: Own calculations.

Figure 7.5 depicts the investments in DC lines, realized among the 23 options provide by the backbone architecture. Curiously, and contrary to the common belief of pan-European electricity highways, the model only invests in the DC offshore cables between the non-synchronized networks of Ireland, Great Britain, Scandinavia, and continental Europe but not in the onshore DC cables, neither in any DC cable South of France (with one exception in the 80%DEF case). Compared to the high mitigation scenarios, the 40%DEF scenario has one additional cable connecting Great Britain to Germany but one less connecting it to Norway. Sweden is linked to continental Europe by one additional cable in the 40%DEF scenario, two in the 80%DEF scenario, and three in the 80%GREEN scenario. Overall higher DC investments in the 80%GREEN scenario also indicate a stronger integration of the non-synchronized transmission systems around the North and Baltic Seas.



(a) 40%DEF (b) 80%DEF (c) 80%GREEN

Figure 7.5.: DC grid infrastructure investments. Source: Own calculations.

7.4.2. Total cost of investments

Table 7.7 translates the physical transmission upgrades and expansion into monetary investment values. Unsurprisingly, once again, the investments are proportional to network length; the high fixed costs of HVDC line transformers somewhat modifies this proportionality. While the 80% mitigation scenarios show higher investment figures than the 40%DEF scenario, they are identical to each other (57 bn €); therefore, there is no difference in network expansion whether the decarbonization comes from renewable sources or conventional sources.

Table 7.7.: Total investment costs for transmission capacity.

in mn EUR	Technology	2020	2030	2040	2050	Total
40%DEF	**AC**	11,847	168	4,318	6,339	22,672
	DC	5,178	1,834	0	911	7,923
	Total	17,025	2,002	4,318	7,250	30,595
80%DEF	**AC**	12,224	3,397	17,321	14,154	47,096
	DC	6,641	921	1,349	913	9,824
	Total	18,864	4,318	18,670	15,067	56,919
80%GREEN	**AC**	9,330	3,685	8,184	22,633	43,833
	DC	6,641	2,270	2,263	1,827	13,000
	Total	15,971	5,955	10,447	24,460	56,833

Source: Own calculations.

Considering the timing of investments, all scenarios have similar total investment costs by 2030. Investments for 2020 are driven by network expansion to resolve existing bottlenecks (where cost efficient),[75] by better cross-border market integration, and

[75]The initial network topology is not free of congested lines in 2012 causing some network expansion in the first decade.

by the implementation of the European 20-20-20 targets. The transmission network sees a high expansion rate but a low variance of total expansion costs between the scenarios (16-19 bn €). In the following decade, the transformation of the generation portfolio slows down. In the absence of strong commitments to climate targets on the European level between 2020 and 2030 in the PRIMES scenarios, the energy system model postpones investments in generation to later decades and predicts stagnating resource and carbon emission prices. With this model input, the electricity sector model builds only few transmission lines in all scenarios.

After 2030, transmission investments remain at a moderate level with an additional 12 bn € in the 40%DEF scenario. In both high mitigation scenarios, they are ascending to about 34 bn € due to the approaching 80% emission reduction target by 2050. In the 80%DEF scenario more investments occur in 2040 compared to 2050 (19 bn € vs. 15 bn €) while in the 80%GREEN scenario the larger share of investments is in 2050 due to the continuously strong growth in renewable capacities.

7.4.3. Regional

In addition to the total investment costs and kilometers built, the regional character and robustness of the scenarios is an important aspect to consider. We compare two cases; the first is the European case, which is identical to the results presented above. In the regional case, we assume double costs for cross-border infrastructure investment to mimic hurdles of international cooperation and increased transaction costs. As expected, we see fewer kilometers built in the regional cases, especially HVDC investments, which are exclusively cross-border lines (see reduced investments in the regional cases). By comparing the three scenarios, it becomes apparent that the 80%GREEN scenario is least affected by the increased cross-border expansion cost, but only for HVAC. For all scenarios, HVDC investments are more sensitive to the higher cost assumptions due to their cross- border character. The remaining level of HVDC investments is about 50% higher in 80%GREEN compared to the other scenarios. The overall relatively small change of line expansion in the 80%GREEN scenario is in line with the assumption that, with high renewable deployment, the spatially different availability of renewable capacity can be smoothed out overall, given a well- connected electricity transmission grid. Therefore, the 80%GREEN scenario can be interpreted as a robust European scenario. In the 80%DEF scenario, the different mix in generation technologies seems to represent a more national scenario, as here the relative decrease in line expansion is highest (Table 7.8).

Table 7.8.: Total kilometers per line type in the european or regional case (changes in parenthesis)

Scenario	Case	HVDC	HVAC cross-border	HVAC national	Total
40%DEF	European	4,174	4,611	19,194	27,978
	Regional	3,243	4,207	18,860	26,310
		(-22%)	(-9%)	(-2%)	(-6%)
80%DEF	European	5,346	7,173	39,905	52,424
	Regional	3,194	6,808	36,132	46,135
		(-40%)	(-5%)	(-9%)	(-12%)
80%GREEN	European	7,057	4,138	39,799	50,993
	Regional	4,654	4,088	40,967	49,709
		(-34%)	(-1%)	(+3%)	(-3%)

Source: Own calculations.

7.4.4. Comparison with the European Energy Roadmap 2050 and other studies

We now turn to a comparison between our model results and those of the Energy Roadmap 2050, which is the roadmap for the European Union's decarbonization strategy (EC, 2011b) and of other studies introduced in Section 7.1.

This comparison is possible for the Energy Roadmap 2050 as the reference scenario for the Impact Assessment of the Energy Roadmap 2050 (EC, 2011c) is very close to the 40%DEF scenario (with a similar 40% mitigation target), and the decarbonization scenarios include the diversified supply technologies scenario (comparable to 80%DEF) and the high RES scenario (comparable to 80%GREEN). As described in the introduction, the PRIMES model diverges from our methodology due to its aggregated network representation. It also includes both, costs for new line investments and maintenance costs of the existing network, whereas our model does not consider maintenance costs. Overall, we find that both the structure of network expansion and the level of investment into cross-border lines differ significantly from those of the Energy Roadmap 2050. In particular, the Energy Roadmap 2050 sees much higher investments in the high mitigation scenario (EC, 2011b, Table 29).

Other studies show lower cost than the Energy Roadmap as well (Table 7.9). The Grid Study 2030/2050 by Tröster et al. (2011) uses a similar scenario to 80%GREEN, by reaching 99% of renewable share in 2050 for the electricity sector. Fürsch et al. (2013) use a model similar to Tröster et al. (2011) but apply a more conservative scenario definition. By 2050, a GHG emission reduction of 80% is assumed for the electricity sector, compared to 1990. While the calculated costs are lower than the Energy Roadmap 2050, they remain two to three times higher than the costs proposed in this chapter. One explanation is that those studies use a reduced spatial resolution

with cost markups to approximate the entire high-voltage network. Compared to their focus on cross-border lines, the results in this chapter highlight the importance of national transmission investments and network adaption requires less cross-border integration.

Table 7.9.: Transmission cost comparison with other studies

in bn EUR	Spatial resolution	By 2030	2030–2050	Total
Energy Roadmap 2050	One node per country	96.7–148.3	105.5–272.2	205.7–420.4
Tröster et al. (2011)	224 nodes for EU	70–98	74–79	149–173
Fürsch et al. (2013)	224 nodes for EU	70	144	214
This chapter	3,523 nodes	19–23.1	11.5–35	30.6–56.8

Source: Own calculations.

Another point of divergence is the timing of investments: Similar to the model results, network investment costs in the Energy Roadmap 2050 increase for the decarbonization scenarios in future decades and remain on the same level between 2030 and 2050. However, the numbers do not predict the large upfront investments by 2020 and the low investment levels between 2020 and 2030. For Tröster et al. (2011) and Fürsch et al. (2013), investment needs are higher between 2030 and 2050 than they are between 2010 and 2030, especially when North Africa is included.

The assessment of cross-border interconnector investment (Table 7.10) shows differences in the results between our model results and the Energy Roadmap 2050.[76] While results are quite similar in the 40%DEF scenario, they already diverge for the 80%DEF scenario, and particularly so for the 80%GREEEN scenario. As was shown in the previous subsection, our model results indicate quite modest levels of HVAC and HVDC interconnectors, and focus primarily on the early period (before 2020). On the contrary, the European Roadmap 2050 not only has 2.5 times more investment in this period (21.9 bn €), but these even increase to 50.8 bn € for the period 2030 to 2050. In the high RES scenario of the Energy Roadmap 2050, 67.5 GW of investments in offshore connectors in the North and Baltic Seas region (2030—2050) are stated that are determined by exogenous assumptions. In our model results of the 80%GREEN scenario, HVDC lines for offshore wind connection to the HVAC grid are not included and the rather high interconnector investments of the Roadmap's high RES scenario are not observed.

In addition, the network architecture between the two models diverges significantly: while our results suggest only a very modest HVDC expansion, the Energy Roadmap 2050 sites HVDC lines all over Europe. This is in line with the results from Tröster

[76] No separate information on the investments in cross-border lines can be found in Tröster et al. (2011) and Fürsch et al. (2013). Therefore their results are not compared.

Table 7.10.: Interconnector investments in the model results and the Energy Roadmap 2050.

in mn €	before 2020	2021-2030	2031-2050	Total
40%DEF	8,487	1,849	2,769	13,104
Reference	13,100	300	0	13,400
80%DEF	9,850	988	7,529	18,367
Diversified	21,900	9,700	600	32,200
80%GREEN	8,652	2,573	6,262	17,488
High RES	21,900	21,200	50,800	93,900

Source: Own depiction and EC 2011c.

et al. (2011) where investments in HVDC interconnectors are two to three times higher than in HVAC lines. In contrast, Fürsch et al. (2013) see equal investments in HVAC and HVDC lines.

In the results of this chapter, it is not clear whether renewables are really a main driver of (cross-border) network expansion; rather, it seems that the change in the spatial allocation of con- ventional generation technologies (i.e., nuclear and CCTS technology) is also a major driver of transmission investment.

7.5. Conclusion

In this chapter, we present a comprehensive model of the European electricity sector, with a focus on network expansion in different CO_2-mitigation scenarios. The specificity of the model is the spatial disaggregation of the European electricity system, represented by 3,523 nodes (substations) and 5,145 lines. The results are compared to the Energy Roadmap 2050, the benchmark developed for and used by the European Commission.

Our results diverge from most of the available literature, including the Energy Roadmap 2050, in that we find more intra-national HVAC transmission expansion, fewer cross-border interconnector lines, and a very modest level of HVDC transmission expansion. The high granularity of our model allows a differentiation between domestic and cross-border investment. It turns out that, in all scenarios, national investments are two to three times more important than cross-border interconnectors (in km). While national networks have the character of copperplates in the initial HVAC network, they require additional investments to adapt to the changing generation portfolios. Our model also suggests that transmission expansion should take place early (i.e., by 2020) and follow up with additional expansion in the high mitigation scenarios between 2030 and 2050. Overall, the investment levels are quite modest: even in the high-mitigation scenarios (80% CO_2 reduction), total investments do not

exceed 57 bn €, which corresponds to less than 2 bn € per year Europe-wide. The model limitations mostly suggest that the model results provide a lower bound for network investment. However, considering other options for renewable integration like storage capacity or the utilization of demand response could also reduce the level of network investment.

Altering the cross-border transmission cost provides insights in the regional structure of the scenarios. In the case of higher cross-border transmission costs we show that the 80%GREEN scenario has a European character as investment levels in HVAC lines remain on a similar level. It is more robust than the 80%DEF scenario where the relative decrease in investment levels is highest (national character). HVDC investments are more sensitive to the higher cost assumptions due to their cross-border character.

A comparison with the Energy Roadmap 2050 shows significant differences in structural and financial terms: our model focuses on domestic upgrades and new builds, and our investments in interconnectors (17 bn €) are less than one fifth of those in the Roadmap (94 bn €). In addition, we find neither an overlay backbone HVDC network nor significant HVDC lines at all, but rather a few HVDC lines across the North Sea and the Baltic Sea. Finally, there seems to be no difference whether the low-carbon generation is from renewable or conventional capacity (e.g., nuclear and CCTS).

The chapter suggests that i) a spatial differentiation of the electricity sector improves the understanding of the nature of transmission expansion; and ii) while some transmission expansion is required for a low-carbon transformation, its importance is modest, in particular when compared to the huge efforts required for low-carbon electricity generation.

Part III

A dynamic investment perspective

Chapter 8

A dynamic investment and dispatch model for the future European Electricity Sector (dynELMOD)

This chapter is based on DIW Berlin Data Documentation No. 88 (Gerbaulet and Lorenz, 2017). The model and data are published under an open source license. Previous versions were presented at 14th IAEE European Energy Conference 2014 in Rome, Italy, the 9th Annual Trans-Atlantic Infraday (TAI 2015) in Washington, USA, the 9th Conference on Energy Economics and Technology (ENERDAY 2014), Dresden, and the 11th International Conference on the European Energy Market (EEM 2014), with a publication as a IEEE Conference Publication (Gerbaulet et al., 2014). Findings and policy implications of model applications are also published in the DIW Economic Bulletin 41/2015 *Future of nuclear power* (Kemfert et al., 2015), and the DIW Economic Bulletin 44/2016 *Nuclear power in Europe* (Lorenz et al., 2016).

8.1. Introduction

The future development of the European electricity system is intensively discussed with respect to the electricity network as well as the role of electricity generation and storage technologies. Renewable generation is assigned a dominant role with the underlying aim to reduce the carbon intensity of the entire electricity sector. The electricity sector is taking a vanguard role when it comes to decarbonization due to its high greenhouse gas (GHG) reduction potentials and associated costs compared to sectors such as heat and transport. According to the European Commission (EC) "the electricity sector will play a major role in the low carbon economy" (EC, 2011a).

Electricity sector decarbonization also offers the possibility to substitute fossil fuels in transport and heating. In contrast to other sectors many low carbon technologies already exist today such as wind and solar fueled technologies. This is reflected in also in the sectoral decarbonization potentials estimated by the EC (Table 8.1).

This chapter presents the open-source dynamic investment and dispatch model dynELMOD, which provides a tool to determine future pathways of the European electricity system under carbon dioxide (CO_2) emission constraints.

Many stakeholders from science and industry highlight the possibility and necessity of a fully renewable electricity system: the need of a fast switch towards such a system is analyzed in Pfeiffer et al. (2016). They show that no new investments into new GHG-emitting electricity infrastructure can be done after 2017, as these capacities would emit too much CO_2 over their lifetime to still adhere to the 2°C target. This includes the assumption, that other sectors reduce emissions in line with a 2°C target along with the electricity sector. Scenario analyses by Prognos (2014) validate this for Germany by estimating that a power mainly fueled by solar photovoltaic (PV), wind and gas backup capacities has up to 20 percent lower costs than a system containing a combination of gas and nuclear power plants, in which the costs for backup gas power plants are much lower than the cost of the nuclear power plants. Heide et al. (2010) show, that "For a 100% renewable Europe the seasonal optimal mix becomes 55% wind and 45% solar power generation." In this configuration the least amount of storage capacities are required. With a lower renewable penetration, the optimal share of wind decreases and the share of solar increases. The importance of electricity storage technologies will increase, as the amount of electricity generated by fluctuating renewable energy sources (RES) is very likely to increase in the future (see Zerrahn and Schill, 2015a).

Using Germany as an example, Agora Energiewende (2017) shows that a renewable system is cheaper and less dependent on fuel price increases than a fossil based electricity system. Even for renewable shares up to 60% percent the cost of allowing renewables into the electricity system are very low and additional storage capacities

Table 8.1.: GHG reductions and potentials in the European Union

GHG reductions compared to 1990	2005	2030	2050
Total	-7%	-40 to -44%	-79 to -82%
Power (CO_2)	-7%	-54 to -68%	-93 to -99%
Industry (CO_2)	-20%	-34 to -40%	-83 to -87%
Transport (incl. CO_2 aviation, excl. maritime)	30%	+20 to -9%	-54 to -67%
Residential and services (CO_2)	-12%	-37 to -53%	-88 to -91%
Agriculture (non-CO_2)	-20%	-36 to -37%	-42 to -49%
Other non-CO_2 emissions	-30%	-72 to -73%	-70 to -78%

Source: (EC, 2011a, p. 6)

are still not required (Deutsch and Graichen, 2015). Hence, for Germany additional storage capacity seems not to be necessary before 2035, when the development of renewables follows the corridor laid out in the German Renewable Energy Sources Act (EEG, Erneuerbare-Energien-Gesetz). Furthermore, the cost for renewable integration can be reduced due to spatial and technological diversification.

8.1.1. Modeling the European electricity sector

Several approaches exist that examine the future development of the European energy or electricity sector. Widely used methods are simulation and optimization models. The optimization models described in this section can be distinguished according to i) the regional coverage and spatial resolution, ii) the number and resolution of time steps (e.g. years) and whether a myopic or integrated optimization takes place, iii) the number and resolution of considered time slices within a time step, iv) the implemented sectors and model interfaces to other sectors, and v) boundary conditions and targets such as starting the optimization using a brownfield or greenfield approach or decarbonization targets. The actual model implementation is often the product of balancing accuracy in technology or economic representation, spatial and temporal resolution and computational possibilities to keep the model tractable. Connolly et al. (2010) and Després et al. (2015) give further overviews over long-term energy modeling tools and their characteristics.

8.1.2. Transparency and open source models

Traceability and transparency are very important for large-scale models as various assumptions influence the results. Only if all assumptions and data is available model results can be validated and trusted.

Apart from the need to publish all data and models for scientific credibility and transparency there is an ongoing trend to publish the data and models under open

source licenses. This allows all stakeholders to base their work upon previous work and to prevents double work within the scientific community. The number of publications under open licenses has been rising in recent years. On the one hand entire models including their data set are published, see Abrell and Kunz (2015), Bussar et al. (2016), Egerer (2016), Howells et al. (2011), SciGRID (2017), Wiese et al. (2014), and Zerrahn and Schill (2015a). On the other hand complete data sets for direct use are provided by Egerer et al. (2014), OPSD (2016), and Schröder et al. (2013a). dynELMOD also contributes to this trend, since both source code and all necessary data to reproduce the model results are published parallel to this publication.

The remainder of this chapter is as follows. Section 8.2 gives an overview of the existing model landscape, Section 8.3 discusses the model dynELMOD, methodological considerations of the model implementation and provides the model formulation. In Section 8.4 the data used in this application is described. Section 8.5 provides the methodology of the time-series reduction technique developed for dynELMOD. The Results are provided in Section 8.6. A critical discussion of model limitations is given in Section 8.6.5. Section 8.7 concludes.

8.2. Large variety of investment models

Despite their high complexity, the political relevance of the future development of the power mix in Europe has lead to the existence of several investment models. Models with the focus on Europe are described in this section.

The most well known model is the Price-Induced Market Equilibrium System (PRIMES) model as depicted in Capros et al. (2014, 1998). It is an integrated energy system model, which covers the EU27 European energy system. It provides the basis for the European Commission's scenarios regarding the development of the electricity sector EC (2009d, 2011c,d,e, 2013, 2014b). Mantzos and Wiesenthal (2016) develop the POTEnCIA (Policy Oriented Tool for Energy and Climate Change Impact Assessment) model for the EC which is in beta phase as of early 2017. It features a hybrid partial equilibrium approach which allows to analyze technology-oriented policies and of those addressing behavioral change. Ludig et al. (2011) introduce the Long-term Investment Model for the Electricity Sector (LIMES), which allows for investment in generation as well as transmission capacities. LIMES has been used to analyze different effects on the German and European electricity system in several studies (see Haller et al., 2012; Ludig et al., 2011; Schmid and Knopf, 2015). In LIMES, the cross-border flow representations interaction is implemented as a transport model. A similar methodology is applied by Pleßmann and Blechinger (2017). They adapt the linear power system model elesplan-m to model the transition

of Europe's power system towards renewable energies. The electricity grid is reduced to 18 interconnected European regions using a transport model.

A different methodology regarding the characteristics of transmission networks can be found in applications of the DIMENSION (Dispatch and Investment Model for European Electricity Markets) model (Richter, 2011). To account for loop-flows, two approaches for an extension of the model are implemented in Fürsch et al. (2013) and Hagspiel et al. (2014). Fürsch et al. (2013) use a separate model of the transmission grid, while Hagspiel et al. (2014) integrate a power transfer distribution factor (PTDF)-representation, which is an approximation of flow-based cross-border coupling. Both approaches are solved in an iterative fashion, first optimizing market dispatch and infrastructure development then reviewing the effects of investment on the transmission network until both solutions converge. Applications focusing on renewable development or decarbonization of the European electricity sector until 2050 are EWI and Energynautics (2011) and Jägemann et al. (2013). Spiecker and Weber (2014) analyze the impact of fluctuating renewables on endogenous investment decisions for the European power system. They apply a power system model that allows to include uncertainty in power plant dispatch in the short run depending on the amount of renewable infeed. This allows to assess the impact of stochastic power feed-in on the endogenous investments in power plants and renewable energies. Stigler et al. (2015) introduce ATLANTIS, a European electricity sector model. It includes 29 countries of continental Europe, and a node sharp demand resolution, direct-current load flow (DCLF) calculations and a unit sharp dispatch. The open source Electricity Market Model (EMMA) by Hirth (2015) includes the Northwestern European power market for which its determines power plant investments and linear dispatch decisions. Möst and Fichtner (2010) developed the model PERSEUS-RES-E which optimizes the power plant portfolio for the EU-15 countries within a time horizon until 2030. A well-known open source energy modeling system is OSeMOSYS (Howells et al., 2011). It can be used to evaluate the future development of energy systems. As the time resolution of most applications is very low, the correct representation of flexibility options is challenging. Welsch (2013) includes flexibility constraints in OSeMOSYS, but also uses a limited time slice resolution of 8 hours.

In addition to the partial equilibrium and optimization models mentioned above, simulation models are also frequently used to answer similar questions. These models have the advantage of being able to include various non-linear calculations and constraints but must not necessarily reach an optimal solution, as they use iterative steps or the coupling of different modules to reach a solution. Wiese et al. (2014) have published a fully open source energy system model called renpass (Renewable Energy Pathways Simulation System), which uses a simulation approach to determine cost-efficient portfolios for decarbonized electricity systems.

The model GENESYS (Bussar et al., 2016) also optimizes the European power system, and does – in contrast to most models – not rely on direct mathematical optimization or simulation methods but uses a genetic algorithm.

Coupling a long-term energy system model to a unit commitment model (UCM) is done in Després (2015). Here the POLES model (Prospective Outlook on Long-term Energy Systems) is coupled with a short-term European Unit Commitment And Dispatch model (EUCAD). The dispatch model is not solved for a whole year but for six clustered days. Després et al. (2017) build on this framework and analyze the need for storage as flexibility options in Europe.

8.2.1. Model configuration is crucial

The variety of investment models shows that there can be substantial differences in the configuration of models. These effects are not easily tractable and can not be compared as easy as assumptions regarding input data. Hence, model comparisons as done in the Weyant et al. (2013) are crucial. Also Mai et al. (2015) show that model configurations and assumptions can strongly influence model investment decisions. Mai et al. analyze how model investment decisions depend on model configurations such as different assumptions regarding capacity credit or inclusion of certain model features vary. Kannan and Turton (2013) analyze the impact of increased time resolution in the TIMES model and find that improved temporal resolution greatly improves insights into electricity generation behavior, given the limitations of the TIMES model, as it can not replace a dispatch model. Nicolosi (2011) finds that in model runs with low temporal resolution, the importance of conventional power plants is overstated and that the temporal resolution of such investment and dispatch models significantly influences the result. Pfenninger et al. (2014) also address the challenges of future energy systems modeling and that the increasing complexity of the future electricity systems needs to be represented adequately.

In systems with high demand and feed-in fluctuations, the ramping and startup flexibility of the existing conventional power plant might not be sufficiently represented in linear optimization models. Some papers aim to achieve an improved representation of power plant properties through the implementation of mixed integer linear program (MILP) constraints, at the expense of a drastically higher computational complexity. Poncelet et al. (2014a) lay the groundwork for integrating a unit commitment formulation into investment models, that can (accompanied by a loss in accuracy) also used in a linearized version. The investment model IMRES (de Sisternes, 2013) also includes MILP constraints for thermal units, but is not applied in a long term application.

8.3. The model dynELMOD

dynELMOD (**dyn**amic **El**ectricity **Mod**el) is a dynamic partial equilibrium model of the European electricity sector which determines cost-effective development pathways. It i) decides upon investment in conventional and renewable generation and network capacities for the European electricity system and ii) calculates the dispatch for an entire year based on the investment result, or exogenously given capacity scenarios.

Starting point is the currently available power plant portfolio which will be phased out over time due to its limited technical lifetime. Investments into new generation capacities are done in the light of the decarbonization pathway that determines the remaining CO_2 emissions. The model optimizes the investments in a dynamic way as for each year all upcoming years with their respective CO_2, demand, fuel and investment cost developments are taken into account.

The modeling approach presented in this chapter is comparable to many of the previously described modeling approaches, as it integrates the two decision levels: market dispatch and investment in transmission and generation. It also allows for tackling the problem of loop-flows that occur in alternating current (AC) grids and includes options to limit the model foresight, to implement myopic behavior. Given exogenous scenario targets for certain technologies, it also determines the cost-minimal pathway to reach these scenario targets. Furthermore, it verifies the optimization result in a dispatch model run with 8,760 model hours. When all capacities are given exogenously, it functions as a dispatch model.

dynELMOD is currently applied to a dataset covering every European country in the period from 2015 to 2050 in five-year steps. The geographical resolution is one node per country, 33 European countries are included in the model. This covers five different synchronous areas show in different color in Figure 8.1.[77] In this application, possible points of interconnection with Northern parts of Africa are not taken into account.

8.3.1. Methodology and calculation procedure

In order to reduce complexity we separate the calculation into two steps:

First, the investment decision into power plants and grid is using a reduced time set for the dispatch calculations. Second, the optimized investment decision are fixed and the dispatch is calculated for the entire time set to calculate the final generation and to determine whether an adequate generation portfolio has been found. Both

[77] In this application we consider the high-voltage alternating current (HVAC) grids of both Denmark east and Denmark west as part of the continental synchronous area.

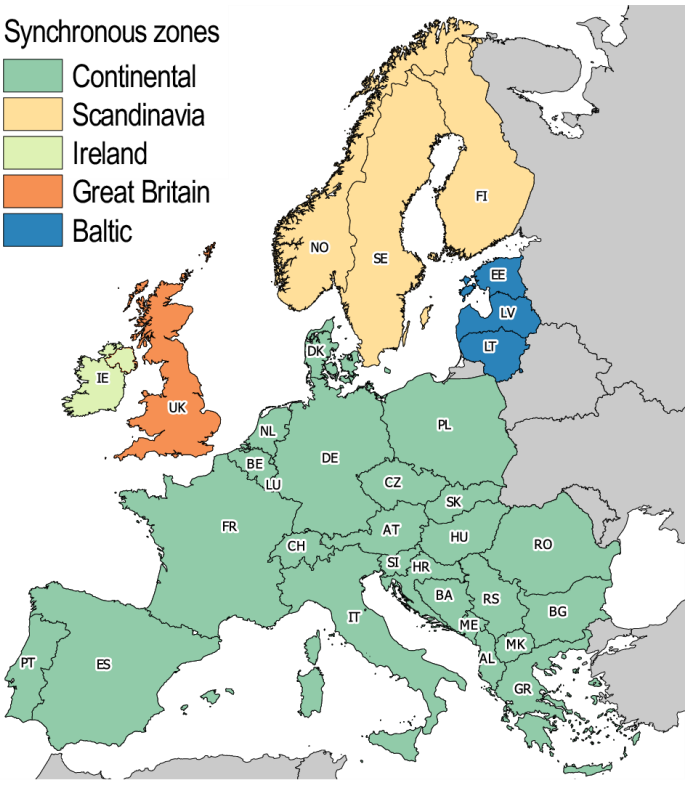


Figure 8.1.: dynELMOD geographical coverage

calculation steps use the same boundary conditions that have been derived from the input parameters.

Figure 8.2 shows an overview of the boundary conditions, calculation procedure and model outcomes and will be explained in the following. The input parameters can be classified into three categories: data about the existing infrastructure, future development assumptions and future constraints which in conjunction form the boundary conditions. The existing data consists of i) the current power plant portfolio which decreases over time as the lifetimes of the power plants are reached, ii) the existing cross-border grid infrastructure and iii) time series for load and RES production. The future developments are characterized by assumptions regarding the change of i) investment and operational cost, ii) fuel cost iii) full load hours (FLH) and iv) load. Constraints limiting the solution space are i) the European wide CO_2 emission limits, ii) regional carbon capture, transport and storage (CCTS) storage availability iii) overall and yearly investment limits and iv) regional fuel availability. Those boundary conditions are then used in both subsequent calculation steps:

1. Investment The objective of this step is to determine investments into electricity generation infrastructure, storage capacities and cross-border grid capacities. To

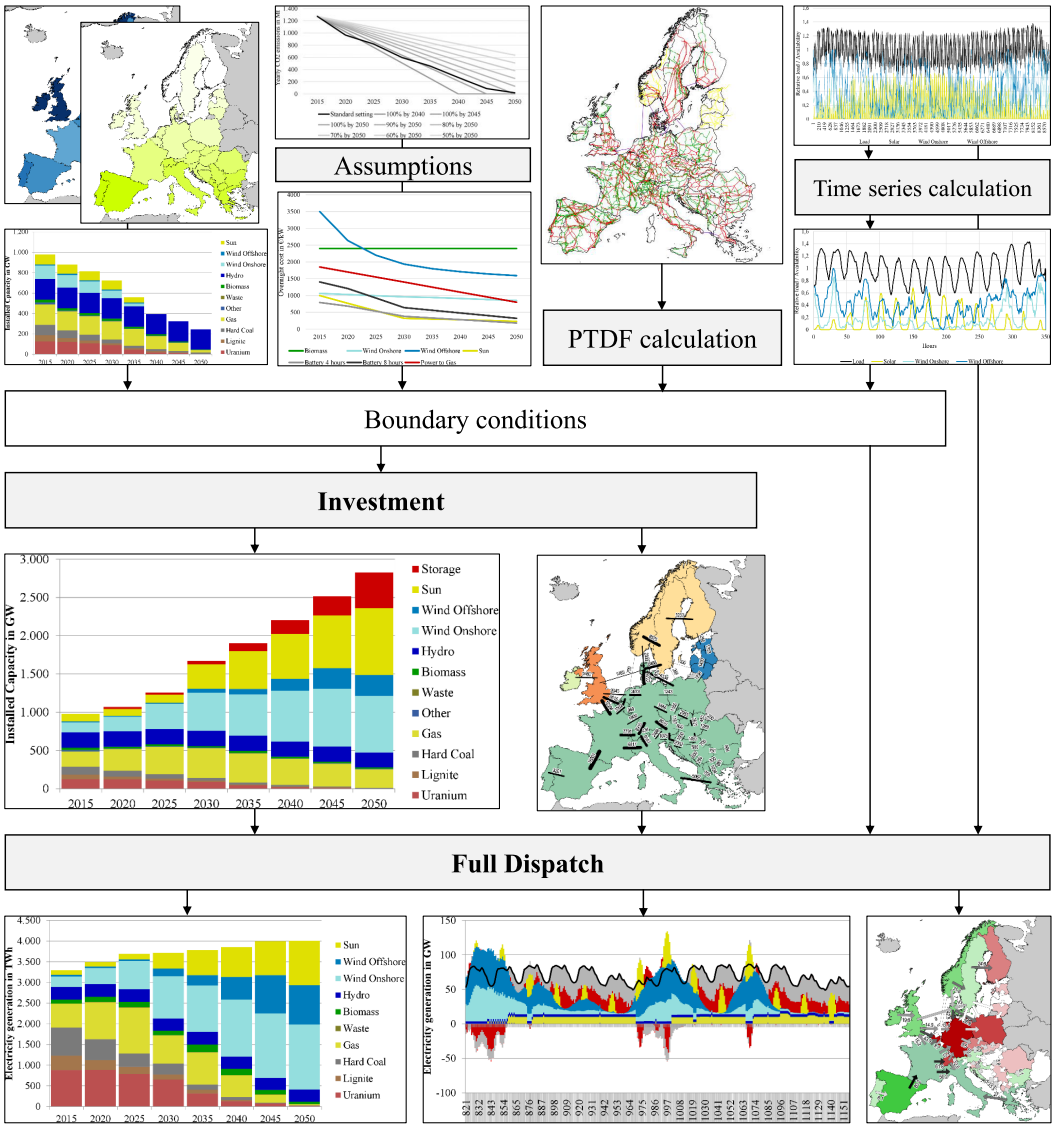


Figure 8.2.: dynELMOD calculation procedure

reduce computation complexity and allow for the representation of a large-scale geographical region we reduce the hours that will be included in the model. Instead of all 8,760 hours of one year, we only use certain hours depended on model complexity. To determine these hours, we apply a time frame reduction technique (see Section 8.5), that covers the characteristics of seasonal and time-of-day variations in the input parameters. With this reduced time frame the cost-minimal investments into the power plant portfolio are determined. In the standard setting, the length of the reduced time frame is 351 hours.

2. Dispatch After calculating the cost-minimal electricity generation portfolio, the model is solved again with the entire time set of 8,760 hours. In this step the

investments are fixed. This allows us to test the reliability of the power plant portfolio in a much wider range of cases and to verify that the determined power plant portfolio ensures system adequacy.

Afterwards, the results from both the *investment* and *dispatch* runs are used to generate the model output.

8.3.2. dynELMOD model formulation

The model includes two decision levels, the dispatch and the investment in transmission and generation. These levels are reduced to one level assuming perfect competition and a central planer that minimizes total system cost. The model is formulated as a linear program (LP) consisting of equations (8.1) to (8.34) in the General Algebraic Modeling System (GAMS). It is solved using commercially available solvers such as GUROBI or CPLEX.

Objective function The objective of total system cost *cost* (8.1) include variable cost for generation $cost^{gen}$ (8.2), investment cost for new built generation $cost^{inv}$ (8.3), fixed operation and maintenance cost for existing and new built generation capacity $cost^{cap}$ (8.4), and investment cost for network expansion $cost^{line}$ (8.5). The nomenclature for all sets, variables and parameters can be found in Section D. Variable cost for existing capacity are considered on a block level, whereas new built capacities are aggregated by technology and depend on the commissioning date of the respective generation capacity. In order to ensure a consistent representation of the investment cost, annuities are calculated using a discount rate I^i. Furthermore, all cost components are discounted with the interest rate I^d which results the discount factor DF_y.

$$\min cost = cost^{gen} + cost^{inv} + cost^{cap} + cost^{line} \tag{8.1}$$

$$\begin{aligned} cost^{gen} = & \sum_{co,i,t,y,p} Cvar_{p,co,i,y} * g^{existing}_{p,co,i,t,y} * DF_y \\ & + \sum_{co,i,t,y,yy,yy \leq y} Cvar^{newbuilt}_{co,i,y,yy} * g^{newbuilt}_{co,i,t,y,yy} * DF_y \\ & + \sum_{co,i,t,y,yy} Cload_{co,i,y} * (g^{up}_{co,i,t,y} + g^{down}_{co,i,t,y}) * DF_y \end{aligned} \tag{8.2}$$

$$\begin{aligned} cost^{inv} = & \sum_{co,i,y,yy,yy \leq y} Cinv_{i,yy} * inv^{cap}_{co,i,yy} * DF_y \\ & + \sum_{co,i,y,yy,yy \leq y} Cinv^{stor}_{i,yy} * inv^{stor}_{co,i,yy} * DF_y \end{aligned} \tag{8.3}$$

$$cost^{cap} = \sum_{co,i,y} Cfix_{co,i,y} * (\sum_{p} G^{max}_{p,co,i,y} + \sum_{yy} inv^{cap}_{co,i,yy} + inv^{stor}_{co,i,yy}) * DF_y \tag{8.4}$$

$$cost^{line} = \sum_{yy,co,coo} Cline_{co,i,y} * 0.5 * inv^{line}_{yy,co,cco} * DF_{yy} \tag{8.5}$$

The investment cost in dynELMOD are accounted for on an annuity basis. When investments occur, not the entire cost is accounted for in the year of investment, but the to-be-paid annuities are tracked over the economic life time of the investment, also taking into account the remaining model periods to ensure no distortion due to the end of the model horizon. The tracking of the remaining periods is not shown for clarity.

All equations above are also scaled depending on the length of the time frame t to represent yearly values, if necessary. This ensures a distortion-free representation of all cost-components regardless of the time frame included in the model. Furthermore, the equations (8.2) to (8.5) are scaled with a scaling parameter to ensure similar variable magnitude orders. This helps the solver to achieve fast solution times. In (8.5) the line expansion is multiplied by 0.5 as the investment is tracked on "both sides" of the line.

Market clearing The market is cleared under the constraint that generation has to equal load at all times including imports or exports via the HVAC or high-voltage direct current (HVDC) transmission network (8.6). Depending on the grid approach, the equation (8.6) contains either the variables to represent the network using a PTDF and HVDC-lines or, in the case of the net transfer capacity (NTC)-Approach contains the flow variable between countries.

$$\begin{aligned} 0 = Q_{co,t,y} - \sum_{i} g_{co,i,t,y} & \\ \left.\begin{aligned} &+ni_{co,t,y} \\ &+\textstyle\sum_{cco} dcflow_{co,cco,t,y} \\ &-\textstyle\sum_{cco} dcflow_{cco,co,t,y} \end{aligned}\right\} & \text{Flow-based approach} \qquad \forall y, co, t \\ \left.+\textstyle\sum_{cco} flow_{cco,co,t,y}\right\} & \text{NTC approach} \end{aligned} \tag{8.6}$$

Generation restrictions The conventional generation is differentiated into generation of existing and newbuilt capacity and is constrained by the installed capacity, taking into account an average technology specific availability as defined in (8.8) and (8.9). For non-dispatchable technologies availability is defined for every hour and is calculated during the time series scaling described in Section 8.5. Together with the loading and release from the storage the generation from newbuilt and existing

capacities is summed up to a joint generation parameter in equation (8.7). The variable representing the generation from new built capacity is additionally dependent on a second set of years which represent the year when the capacity has been built. The same holds for the variable representing the newbuilt capacity. Equation (8.10) defines the generation of renewable capacities. Here the generation can be less than the available capacity in each hour, without accumulating curtailment cost in the system.

$$\begin{aligned} g_{co,disp,t,y} = & \sum_{p} g^{existing}_{p,co,disp,t,y} + \sum_{yy \leq y} g^{newbuilt}_{co,disp,t,y,yy} \\ & + stor^{Release}_{co,i,t,y} - stor^{loading}_{co,i,t,y} \end{aligned} \qquad \forall co, disp, t, y \qquad (8.7)$$

$$g^{existing}_{p,co,disp,t,y} \leq Ava_{co,disp,y} * G^{max}_{p,co,disp,y} \qquad \forall p, co, disp, t, y \qquad (8.8)$$

$$g^{newbuilt}_{co,disp,t,y,yy} \leq Ava_{co,disp,y} * inv^{cap}_{co,disp,yy} \qquad \forall co, disp, t, y, yy \qquad (8.9)$$

$$\begin{aligned} g_{co,ndisp,t,y} \leq & \sum_{yy \leq y} ResAva^{newbuilt}_{co,t,ndisp,yy} * inv^{cap}_{co,ndisp,yy} \\ & + \sum_{p} ResAva^{existing}_{co,t,ndisp} * G^{max}_{p,co,ndisp,y} \end{aligned} \qquad \forall co, ndisp, t, y \qquad (8.10)$$

Fuel restriction Some fuels (e.g. biomass) face a limitation on their yearly consumption. Therefore the total energy output from this fuel is restricted as defined in (8.11). In scenarios where multiple technologies compete for a fuel (e.g. Biomass and Biomass with CCTS) it also determines an efficient endogenous share between these technologies.

$$\sum_{p,i,t} \frac{g^{existing}_{p,co,i,t,y}}{\eta^{existing}_{p,co,i,y}} + \sum_{i,t,yy \leq y} \frac{g^{newbuilt}_{co,i,t,y,yy}}{\eta^{newbuilt}_{co,disp,yy}} \leq Gen^{max}_{co,f,y} \qquad \forall co, f, y \qquad (8.11)$$

Combined heat and power The combined heat and power (CHP) constraint is implemented as a minimum run constraint that depends on the type of power plant as well as the outside temperature. Thus $g^{existing}_{p,co,i,t,y}$ has to be equal or greater than $G^{min\_chp}_{p,co,i,t}$. The constraint is only valid for existing power plants as it would have unintended side-effects when also applied to new built technologies. Due to the minimum generation constraint the new built capacities would have to produce and hence emit CO_2. This could potentially violate the emission constraint and thus investment into fossil power plants would not be possible.

$$g^{existing}_{p,co,i,t,y} \geq G^{min\_chp}_{p,co,i,t} \qquad \forall co, i, t, y \qquad (8.12)$$

Investment restrictions Equations (8.14) and (8.15) limit the maximum investment in conventional generation and storage technologies. The parameter $G^{max\_inv}_{co,c,y}$ is scaled according to the number of years between the time steps to account for a yearly investment limit.

$$g^{instcap}_{co,i,y} = \sum_{p} G^{max}_{p,co,i,y} + Storage^{maxrelease}_{co,i,y} + \sum_{yy \leq y} inv^{cap}_{co,i,yy} \qquad \forall co, i, y \qquad (8.13)$$

$$g^{instcap}_{co,i,y} \leq G^{Max\_installed}_{co,i,y} \qquad \forall co, i, y \qquad (8.14)$$

$$\sum_{co,i} inv^{cap}_{co,i,y} \leq G^{max\_inv}_{co,i,y} \qquad \forall co, i, y \qquad (8.15)$$

Ramping In the model, ramping of technologies is implemented in two ways: On the one hand, for some technology types, the ramping speed is limited. Here equation (8.16) and (8.17) limit the relative rate of generation output change per hour. As this model is applied on an hourly basis, this limitation only applies to a subset of generation technologies (e.g. Lignite). Further, to represent a more economic dispatch behavior regarding ramping, wear and tear of the materials within the power plant as well as additional fuel consumption for ramping are represented using ramping costs. The linear model cannot contain binary or integer variables. Thus, the assumed costs for ramping are slightly higher than in a unit commitment model to account for this model characteristic. The load change cost of ramping does not need to be tracked for each p, as the ramping speeds are tracked on a technology level (8.18).

$$g^{up}_{co,c,t,y} \leq R^{up}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{up}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co, i, t, y \qquad (8.16)$$

$$g^{down}_{co,i,t,y} \leq R^{down}_{i,y} * \sum_{p} G^{max}_{p,co,i,y} + \sum_{yy \leq y} R^{down}_{i,yy} * inv^{cap}_{co,i,yy} \qquad \forall co, i, t, y \qquad (8.17)$$

$$g^{up}_{co,i,t,y} - g^{down}_{co,i,t,y} = g_{co,i,t,y} - g_{co,i,t-1,y} \qquad \forall co, i, t, y \qquad (8.18)$$

Emission restrictions In the standard setting, a yearly CO_2 emission limit spanning the entire electricity sector is implemented. The amount of available emissions represents the amount available to the electricity sector. In case a total emission budget spanning the entire model horizon is in place, the emission limit of the first and last model period will still be active. On the one hand, the power plant dispatch in the starting period – where no investments take place – should not be affected by future decisions. On the other hand, the final emission target is also adhered to.

$$\begin{aligned} Emissionlimit_y \geq & \sum_{p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \quad \forall y \tag{8.19}$$

$$\begin{aligned} \sum_y Emissionlimit_y \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{emission}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{emission,new}_{co,i,yy} \end{aligned} \tag{8.20}$$

CCTS As carbon capture and storage plans are implemented as normal generation technologies, additional constraints account for the total amount of CO_2 that can be stored. As we assume that no large-scale carbon transport infrastructure emerges in the future, the captured emissions need to be stored locally within each country. This leads to country-sharp CCTS constraints that are valid for all model periods.

$$\begin{aligned} CCTSStor^{Capacity}_{co} \geq & \sum_{y,p,co,i,t} g^{existing}_{p,co,i,t,y} CarbonRatio^{sequestration}_{p,co,i,y} \\ & + \sum_{y,co,i,t,yy \leq y} g^{newbuilt}_{co,i,t,ys,yy} CarbonRatio^{sequestration,new}_{co,i,yy} \end{aligned} \quad \forall co \tag{8.21}$$

Storage The operation of storages is constrained in equations (8.22 to 8.26). On the one hand the storage operation is limited by the installed loading and release capacity which can be increased by the model (8.22, 8.23). On the other hand the release and loading is constrained by the current storage level defined in equation (8.24).[78] The storage level in return is limited by minimum and maximum storage levels that can be increased by the model independently from turbine and pump capacity (8.25, 8.26). Therefore the model can decide upon the optimal energy to power ratio (E/P-Ratio).

$$stor^{release}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxrelease}_{co,s,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \quad \forall co, s, t, y \tag{8.22}$$

$$stor^{loading}_{co,s,t,y} \leq Ava_{co,s,y} * Storage^{maxloading}_{co,S,y} + Ava_{co,s,y} * \sum_{yy \leq y} inv^{cap}_{co,s,yy} \quad \forall co, s, t, y \tag{8.23}$$

[78] The storage level in the first modeled hour must equal the storage level in the last modeled hour, to ensure continuity at the end and the start of each year.

$$stor^{level}_{co,s,t,y} = stor^{level}_{co,s,t-1,y} - stor^{Release}_{co,s,t,y} + \eta^{storage}_{co,s,y} * stor^{loading}_{co,s,t,y} + Inflow_{co,s,y,t} \quad \forall co, s, t, y \tag{8.24}$$

$$stor^{level}_{co,s,t,y} \leq Storage^{maxlevel}_{co,s,y} + \sum_{yy \leq y} inv^{stor}_{co,i,yy} \quad \forall co, s, t, y \tag{8.25}$$

$$stor^{level}_{co,s,t,y} \geq Storage^{minlevel}_{co,s,y} \quad \forall co, s, t, y \tag{8.26}$$

Demand-side-management DSM is also expected to increase the flexibility in the electricity system. In dynELMOD we focus on demand side management (DSM) where the total demand remains constant overall but can be delayed several hours. In order to keep the model structure simple, we implement DSM as a storage technology. In addition to the standard storage equations, DSM requires further constraints. Depending on the DSM technology models, usage cost occur, and the maximum hours of load shifting need to be tracked. We implement DSM based on a formulation by Göransson et al. (2014). As DSM uses the storage equations framework as a basis, most of the implementation is reversed compared to the formulation by Göransson et al. (2014). An alternative implementation by Zerrahn and Schill (2015b) would enable a slightly more accurate tracking of demand-shifts, but the computational overhead was too high to include this formulation in the model. In addition to the equations for normal storages DSM are restricted by the equations (8.27 - 8.28). The $stor^{level}_{co,dsm,t,y}$ for all DSM technologies is also tracked to be equal at the beginning and end of the model period.

$$\sum_{tt,tt+dsmratio \geq t, tt \leq t} stor^{Release}_{co,dsm,tt,y} \geq Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} - stor^{level}_{co,dsm,t,y} \quad \forall co, dsm, t, y \tag{8.27}$$

$$\sum_{tt,tt \geq t, tt-dsmratio \leq t} stor^{loading}_{co,dsm,tt,y} \geq Storage^{maxlevel}_{co,dsm,y} + \sum_{yy \leq y} inv^{stor}_{co,dsm,yy} - stor^{level}_{co,dsm,t,y} \quad \forall co, dsm, t, y \tag{8.28}$$

Network restrictions When using the NTC approach, the flow between countries is defined in equation (8.29). The flow between two countries is limited by the available NTC, that can be increased by the model in (8.30) and (8.31) through investments in network infrastructure.

$$flow_{co,cco,t,y} = - flow_{cco,co,t,y} \qquad \forall co, cco, t, y \qquad (8.29)$$

$$flow_{co,cco,t,y} \leq NTC_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (8.30)$$

$$flow_{co,cco,t,y} \geq - NTC_{co,cco} - \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (8.31)$$

When using the PTDF approach a more complex framework is required. For load flow calculations we use a country-sharp PTDF matrix of the European high-voltage AC grid which is relevant in (8.32). DC-interconnectors are incorporated as well (8.33). Equation (8.34) enforces symmetrical line expansion between countries.

$$\sum_{ccco} PTDF_{co,cco,ccco} * ni_{ccco,t,y} \leq P^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (8.32)$$

$$dcflow_{co,cco,t,y} \leq Hvdc^{max}_{co,cco} + \sum_{yy \leq y} inv^{line}_{yy,co,cco} \qquad \forall co, cco, t, y \qquad (8.33)$$

$$inv^{line}_{y,co,cco} = inv^{line}_{y,cco,co} \qquad \forall y, co, cco \qquad (8.34)$$

8.3.3. Model options

dynELMOD can be adjusted regarding the grid approximation or the "planners foresight" depending on the desired analysis, to be able to answer a wide range of questions.

Foresight reduction

In the standard setting, the model is solved for all years in the model with perfect foresight over all optimization periods. To mimic a more myopic behavior, the foresight of the model regarding the upcoming periods can be reduced to limit the anticipation of the planner. The model then assumes that the overall boundary conditions remain constant after the model optimization period ends.

This setting requires iterating over the set of all years included in the model, as the horizon progresses over time. Assuming the foresight period is set to 10 years, the first optimization iteration covers the time steps 2015,[79] 2020, and 2025. In the next step the investments of the year 2015 are fixed. Then the year 2030 is added to the time horizon and the optimization is repeated. Next, the optimizations of 2025 are fixed and the process repeats until the time horizon reaches the final time step.

[79] In the actual model formulation, 2015 is only included as a starting year, the power plant portfolio is not optimized for this year.

CO_2 emission restriction

A further point of discussion regarding the European Union emission trading scheme (EU ETS) is the possibility of banking certificates. Ellerman et al. (2015) show that a rationally behaving agents could minimize their emissions below the given constraint and use the banked allowances once the constraint tightens. This should minimize overall abatement cost. We include this option by replacing the yearly emission constraints by a constraint spanning the whole optimization time frame, thus freely allowing the distribution over the model periods, but keeping the total emissions constraint intact.

Grid approximation

We include the option to represent the transmission grid in our model using two different approaches: A NTC-approach and a flow-based approach using a PTDF-matrix. In both approaches, every country is represented as a single node with interconnection to neighboring countries.

NTC approach Most of the currently applied models use the NTC-approach to approximate electricity flows (Ludig et al., 2011; Richter, 2011). In this setting, the NTC-approach models the grid as a transport model without loop flows. This variant has the advantage of lower computational requirements and corresponding faster calculation times, as well as less required input data compared to the flow-based approach. However, the current developments on the European electricity markets have evolved, as the underlying grid constraints should be reflected in the market. In the Central Western Europe (CWE) region flow-based market coupling has been introduced in 2015. Therefore new long-term models should be able to include flow-based market coupling. The approach in this chapter neglects some specifications of actual flow based market coupling, as neither generation nor load shift keys, which approximate the effect of a change in generation or load in the underlying HVAC grid, are implemented.

Flow-based approach The second option, the PTDF-approach allows for the approximation of flow-based market coupling including loop-flows. This approach is computationally more complex. The calculation of the PTDF requires line-sharp data of the underlying high voltage electricity grid. The country-sharp PTDF is derived from the actual underlying high voltage AC grid of Europe as follows: We determine a node- and line-sharp PTDF based on the inverse of the network susceptance matrix $B_{n,nn}$ and the network transfer matrix $H_{l,n}$. The matrices $B_{n,nn}$ and $H_{l,n}$ are calcu-

lated using the approach based on Leuthold et al. (2012). A line- and node-sharp PTDF matrix can then be calculated using (8.35).

$$PTDF_{l,nn} = \sum_{n} H_{l,n} * B^{-1}_{n,nn} \quad \forall l, nn \tag{8.35}$$

As in dynELMOD zonal data on a country level is needed, we then calculate a zonal PTDF as shown in (8.36).

$$PTDF_{ic,co} = \sum_{n \in co} \frac{PTDF_{l,n}}{N_{co}} \quad \forall ic, co \tag{8.36}$$

Here an equal weight is given to all nodes, as the exact withdrawals and infeeds into the grid are not known to the model before the calculation. An analysis by Boldt et al. (2012) shows that giving an equal weight to the nodes when aggregating the PTDF is sufficiently accurate. The next step of the PTDF-approximation to an aggregated level is conducted in (8.37) using the line-sharp PTDF-representation obtained in (8.36). Here sums over two subsets $l1$ and $l2$ are necessary. $l1$ contains all lines that start in the country co or end in cco, while $l2$ contains all lines that start in the country cco or end in co.

$$\begin{aligned} PTDF_{co,cco,ccco} = & \sum_{l1} PTDF_{l,ccco} \\ & - \sum_{l2} PTDF_{l,ccco} \end{aligned} \quad \forall co, cco, ccco \tag{8.37}$$

The first two sets of the PTDF co, cco determine the country-country connection. The third set $ccco$ is the injecting or withdrawing country. The PTDF then serves as an input for the calculation. In contrast to Hagspiel et al. (2014), the underlying PTDF is not updated in our model although line expansion is taking place. This simplifying assumption is motivated by computational speed and justified by the small effect of the existent line expansion on the overall flow pattern (see Section 8.6), although some loop flow effects are not accounted for.

8.4. Data

For large-scale electricity system models, comprehensive input data is required. The data is derived from different disciplines including engineering, finance and meteorology and different data sources have to be combined and matched. The result are large data sets which are very hard to reconstruct for interested stakeholders.

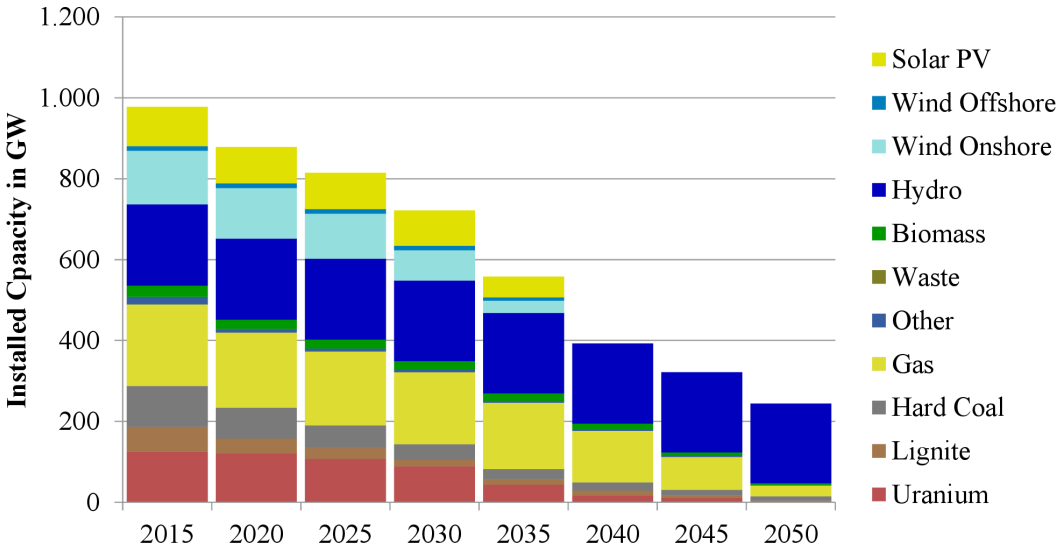


Figure 8.3.: Capacity development of the operational power plant fleet of 2015

Therefore we publish all our input data. We use open source data or own calculations wherever possible. Thereby nearly all final input data can be reproduced.

8.4.1. Generation

We include 31 different conventional and renewable generation technologies in dynELMOD. Table 8.2 shows an overview of the technologies implemented in the model, as well as relevant assumptions regarding costs, efficiencies and lifetimes.[80] Except for Germany, existing generation capacities are aggregated per technology. Existing generation capacities in Germany are included in block sharp resolution. New built capacities are implemented by technology for all countries.

New built capacity is available instantly and lasts for a predefined number of years depending on the technology. Depending on the commissioning date the thermal efficiency, costs for investment and operation and maintenance (O&M) and further characteristics are set. Annuities are calculated based on the economic lifetime. When the remaining horizon is shorter than the to-be-paid annuities or the lifetime of the capacity, this is accounted for in the model formulation to avoid distorting the results by the model horizon's ending. New conventional power plants usually last longer than the end of the model horizon, whereas e.g. batteries have a shorter lifespan.

Most efficiencies, technical lifetimes, overnight cost, load change cost, fix and variable operation and maintenance cost are based on Schröder et al. (2013a). Marginal generation cost are calculated from efficiency, fuel cost and variable maintenance and

[80] Table 8.2 only shows information for 2015 and 2050. The input file accompanying the model also contains assumptions for the development over all intermediate time steps.

Table 8.2.: dynELMOD technology overview

	Technology	Overnight cost [€/KW]		Fix O&M [€/KWy]		Variable O&M [€/MWh]		Efficiency [%]		Technical lifetime [y]		Economic lifetime [y]		Storage capacity [€/KWh]	
		2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050
Fossil	Nuclear	6000	6000	100	100	9	9	0.33	0.34	50	50	30	30		
	Lignite	1800	1800	60	60	7	7	0.43	0.47	40	40	30	30		
	Coal	1800	1800	50	50	6	6	0.46	0.47	40	40	30	30		
	CCGT	800	800	20	20	3	3	0.60	0.62	40	40	30	30		
	OCGT	550	550	15	15	2	2	0.39	0.40	40	40	30	30		
	GasSteam	550	550	15	15	3	3	0.41	0.42	40	40	30	30		
	CCOT	800	800	25	25	4	4	0.60	0.62	40	40	30	30		
	OCOT	400	400	6	6	3	3	0.39	0.40	40	40	30	30		
	OilSteam	400	400	6	6	3	3	0.41	0.42	40	40	30	30		
	Waste	2424	1951	100	100	7	7	1.00	1.00	50	50	30	30		
Renewable	Biomass	2400	2400	100	100	7	7	0.38	0.38	40	40	30	30		
	Reservoir	2000	2000	20	20	0	0	0.75	0.75	100	100	30	30		
	RoR	3000	3000	60	60	0	0	1.00	1.00	100	100	30	30		
	Wind onshore	1063	851	35	35	0	0	1.00	1.00	25	25	20	20		
	Wind offshore	3500	1592	35	35	0	0	1.00	1.00	25	25	20	20		
	PV	998	230	25	25	0	0	1.00	1.00	25	25	20	20		
	CSP	5300	3200	30	30	0	0	1.00	1.00	30	30	30	30		
	Tidal	4608	2600	150	150	0	0	1.00	1.00	50	50	30	30		
	Geothermal	3982	2740	80	80	0	0	1.00	1.00	50	50	30	30		
CCTS	Lignite CCTS	3950	3600	90	90	8	8	0.30	0.33	50	50	30	30		
	Coal CCTS	3550	3200	80	80	8	8	0.31	0.34	50	50	30	30		
	CCGT CCTS	1670	1460	40	40	4	4	0.49	0.52	50	50	30	30		
	OCGT CCTS	1384	1280	30	30	4	4	0.34	0.34	50	50	30	30		
	Biomass CCTS	5630	5140	120	120	8	8	0.26	0.27	50	50	30	30		
Storage	PSP	2000	2000	20	20	0	0	0.75	0.75	100	100	30	30	10	10
	Battery	153	35	3	1	0	0	0.88	0.92	8	13	10	10	625	100
	Powertogas	1850	800	37	16	1	1	0.37	0.37	20	20	20	20	0	0
	DSM01	745	745	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM04	835	835	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM12	30	30	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSMLT	180	40	0	0	0	0	0.80	0.80	10	10	10	10	0	0

Sources: Data compiled form data by Schröder et al. (2013a) and other sources.

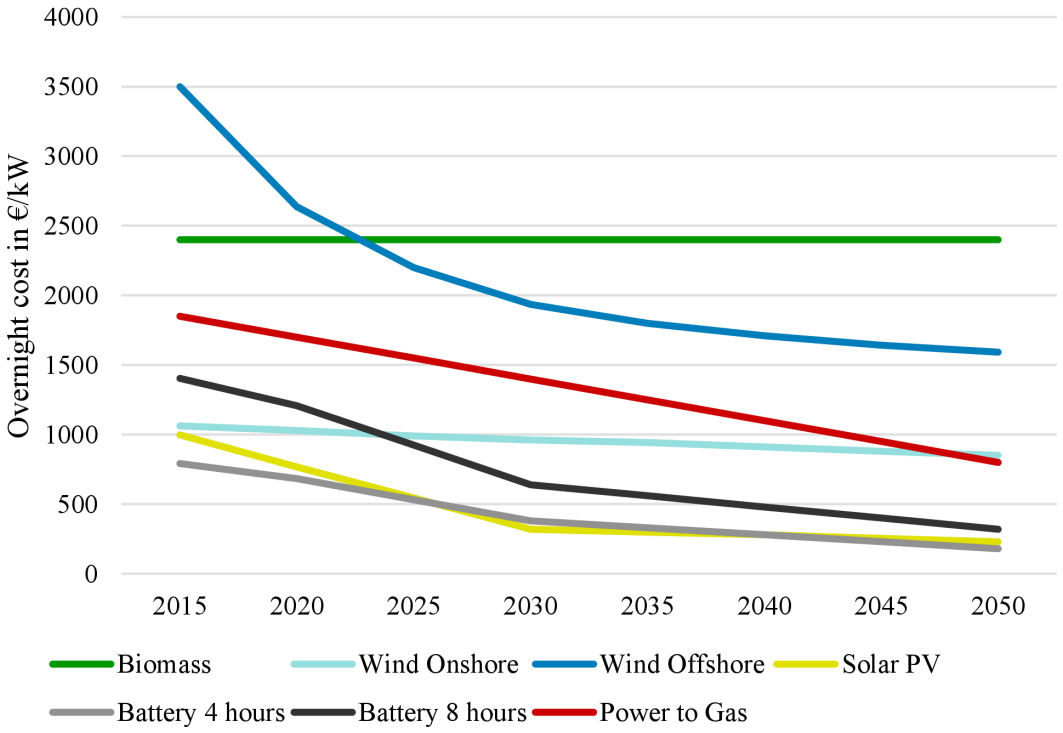


Figure 8.4.: Investment cost pathway for selected technologies

operation cost. When CO_2 prices instead of a CO_2 budget are assumed, additional cost for CO_2 certificates are added depending on emissions. Figure 8.4 shows an overview of the assumed development of overnight costs for selected technologies.

Conventional geneneration technologies

We include ten conventional generation technologies (Lignite, Hard Coal, Combined Cycle Gas Turbine, Open cycle Gas Turbine, Gas Steam, Combined Cycle Oil Turbine, Open Cycle Oil Turbine, Oil Steam, and Waste) which use nuclear fission or the combustion of lignite, coal, gas, oil, and waste for heat generation. Additional constraints apply to those who are providing heat or are equipped with a carbon sequestration technology.

We use the Scenario Outlook and Adequacy Forecast (SOAF) which provides generation capacities per country (ENTSO-E, 2015c). As those capacities only provide a snapshot of current capacities we generate a decommissioning plan for each technology aggregate and and separate per country. Based on the PLATTS (2015) database in combination with economical and technical lifetimes and efficiencies we derived technology and country specific decommissioning plans that also includes efficiency increases. For Germany a block sharp representation based on OPSD (2016) is used instead of the aggregated approach. For lignite power plants in Germany, the

years of shutdown is anticipated based on estimations by Oei et al. (2015a,b). This development of the operational power plant fleet can be seen in Figure 8.3.[81] When technology aggregates are used, the decommissioning of old power plants leads to an increase in average efficiency. This is taken into account in the calculation of the technology aggregates.

Combined heat and power CHP is modeled as a minimum-run constraint on the electricity generation in dynELMOD. For each power generation technology and country a CHP share is defined. This share follows a country-specific minimum heat generation curve based on the average national temperature. For Germany, the power plant blocks with CHP have to follow this curve, as block sharp data is used. New built generation capacities are excluded from CHP minimum run constraints.[82]

Carbon capture, transport, and storage The technology CCTS is often seen as a bridge technology to allow for fossil electricity generation even under decarbonization targets. While the technology theoretically exists, no large scale power plant applications have emerged yet, and near-future adoption of this technology is highly uncertain. Still, we implement CCTS as a potential technology in the model, but at updated cost estimations from Schröder et al. (2013a) as the technological development departs from the expectations in 2013.

We implement two general types of CCTS technologies: Fossil and biomass fueled generation capacities. Biomass is assumed to have no inherent emissions, so that capturing and storing carbon dioxide from biomass leads to negative emissions. For fossil fuels, the majority of carbon dioxide is assumed to be captured (88%, see Schröder et al., 2013a). All captured CO_2 is tracked on a country basis. According to current legislation that does not permit the transport of pollutants and anticipation no change in this regard, captured CO_2 emissions must be stored within each country. Therefore in countries without storage potentials, no construction of CCTS plants is allowed. Storage potentials shown in Table 8.3 are based on Oei et al. (2014) to determine how much CO_2 can be stored. We include only offshore storage capacities in aquifers and depleted gas fields.

Renewables

We include nine renewable technologies (Biomass, Reservoirs, run-of-river power plants (RoR), Wind onshore, Wind offshore, Solar PV, CSP, Tidal Energy, and Geothermal

[81] We assume replacement of run-of-river and pumped storage capacities when their end-of-life is reached.

[82] If new built fossil capacities would have to follow the CHP minimum run constraint, this would effectively prevent investments into these capacities in dynELMOD, as the total CO_2 emission constraint and the minimum run constraint would interfere with each other.

Table 8.3.: CO_2 storage potential per country

Country	Storage Potential [Mt CO_2]
Germany	1,200
Denmark	2,500
Spain	3,500
Ireland	1,300
Netherlands	500
Norway	13,800
Poland	3,500
United Kingdom	22,000
Lithuania	1,300

Source: Oei et al. (2014)

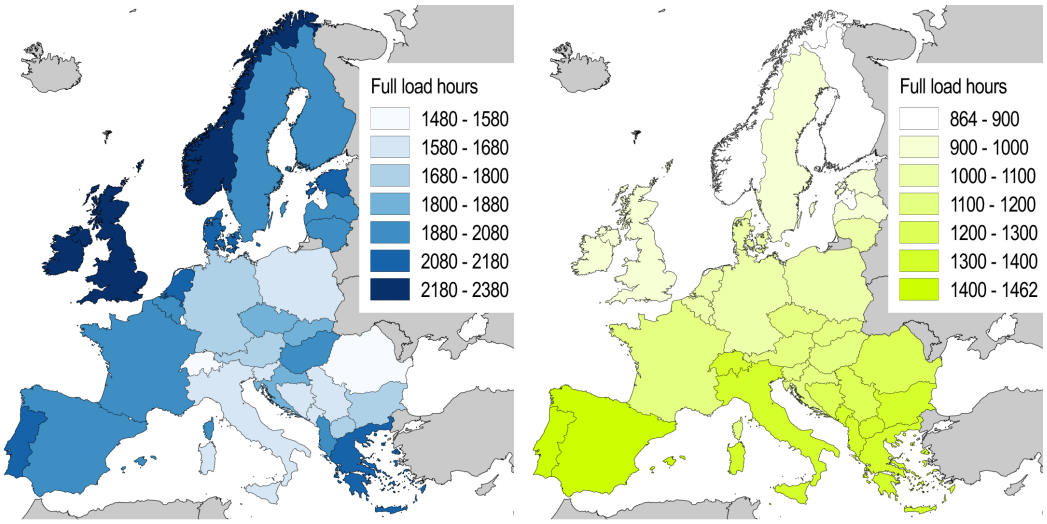
Energy) in dynELMOD, which are characterized by their cost, efficiencies, potentials, time and spatial availabilities.

Wind and solar PV The currently most promising renewables for a continued widespread adoption in the electricity system are solar PV, wind onshore and wind offshore. We limit the potential that can be installed in each country to account for spatial scarcity of space, especially at locations with high availabilities. Furthermore, the potentials are differentiated into three resource grades, similar to the approach by Nahmmacher et al. (2014). Resource grades are used to achieve a distinction between sites of different suitability. The resource grades are characterized by different FLH and thereby represent the varying quality of the potential installation sites for each country. Figures 8.5a and 8.5b show the geographical distribution of FLH for the first resource grade over the model region. As expected in southern Europe, the solar PV potential is highest, while for onshore wind the picture is more diverse.

Biomass The installation potential of biomass fueled power plants is not limited, but the amount of biomass available for electricity generation is restricted due to limits in sustainable biomass supply. This limits the use of Biomass for conventional as well as usage in a CCTS plant, without pre-defining the potential of each technology. In 2015, a thermal potential of 470 $\mathrm{TWh_{th}}$ that is assumed to increase to 1,104 $\mathrm{TWh_{th}}$ until 2050, which corresponds to an electricity production of about 400 $\mathrm{TWh_{el}}$.

Hydro power plants We assume no additional new built capacity for RoR and hydro reservoirs due to limited potentials and environmental concerns. However, current capacity that comes to the end of their technical lifetime will be replaced.

For RoR and hydro reservoirs country specific monthly (in-)flows represent seasonal weather characteristics (ENTSO-E, 2016). In contrast to RoR, hydro reservoirs are implemented using the storage equation framework. Most reservoirs are characterized



(a) Onshore wind (b) Solar PV

Figure 8.5.: Exemplary full load hours for 2015

by a very high E/P-Ratio, such that the amount of storage vastly exceeds the installed electrical turbine capacity. Furthermore, most reservoirs do not have pumping capabilities as the natural inflow is sufficient for reservoir usage.[83] The seasonal inflow patterns as well as the total amount of reservoir inflow have been calibrated using historical data from ENTSO-E (2016). When solving over a reduced time frame the usable reservoir storage capacity is reduced to adequately represent the yearly reservoir storage usage pattern.[84] This accounts for the fact that the seasons are much shorter when using a reduced time frame.

Storage

We include chemical and mechanical storages that are differentiated by their installation potential, round-trip efficiency and cost assumptions. We assume a sharp decline in investment cost for chemical electricity storage technologies. As the cost for battery storage have recently been often below literature estimations our assumptions can still be regarded as conservative. Still there exists great uncertainty and diversity of assumptions between current literature and technology studies that project cost developments for battery storage. Instead of modeling different battery technologies explicitly we assume a generic battery technology that represents an aggregate of assumptions for Lead-Acid, Li-Ion, and Sodium-Sulfur. We base our assumptions on Zerrahn and Schill (2015a) and Pape et al. (2014).

[83] Such reservoirs are implemented in Austria, France, Italy, Norway, Sweden and Switzerland.
[84] The maximum storage level is reduced by the factor *model-hours*/8,760.

For existing pumped hydro storages we assume a E/P-Ratio of 8 hours. For reservoirs country-specific average values are used. In the case of new built battery storages the model is free to invest in storage as well as loading/release capacity separately, thus can decide upon the E/P-Ratio endogenously. In the the model input data the investment cost are differentiated between power €/KW and energy €/KWh to enable this distinction.

In addition to conventional and battery based storage options, power to gas is also implemented in dynELMOD. Although not an electricity storage technology in the traditional sense, we adopt the approach by Zerrahn and Schill (2015a). The E/P-Ratio is fixed at 1,000 hours, and symmetrical gasification and electrification capacities are assumed, which are both included in the investment cost.

Demand side management

Apart from storages we include three different types of DSM. They are characterized by different cost assumptions and either one, four or twelve hours of load shifting. Thereby they represent the different sectors and technologies where DSM potentials can be raised. They all feature a symmetrical discharge and recharging capacity.

We use DSM potentials by Zerrahn and Schill (2015b) for Germany and reduce them to three technology categories. For other countries the DSM potential is scaled according to their yearly load in comparison the yearly load of Germany.

8.4.2. Demand development and sector coupling

In the upcoming years an increasing coupling between the electricity, heat and transportation sector is expected (Agora Energiewende, 2015). The adoption of battery-electric vehicles (BEVs) is likely to increase in the future, and battery prices continue to decrease. At the same time, the current heat sector has a high carbon intensity, which also becomes a target for decarbonization. This decarbonization, in turn, will lead to increasing demand for electricity. As the speed of BEV adoption and interaction of the electricity and heat sector is unclear, the development of the future electricity demand is highly uncertain and might increase substantially. The level of demand also depends on the depth of sector coupling. However, the additional demand for flexibility in electricity supply might also be met directly by the sectors themselves, as the additional demand could be flexible and even provide additional value to the electricity sector.

We assume an increase in electricity demand over time based on EC (2016) as well as an increase in demand flexibility options. Direct demand flexibility is modeled as DSM. As dynELMOD covers the electricity sector only, additional flexibility resulting from other sectors is not represented directly. We model the flexibility of the other

sectors implicitly using the storage and DSM equation framework with the help of a custom DSM technology (named DSMLT). This DSM technology has an asymmetrical release and loading ratio of 24 to 1, where for every hour of discharge, 24 hours to recharge are required. Thus, a very high discharge capacity is available which will cause a long but low recharging period. This artificial storage should represent a short consumption interruption (for example for charging battery vehicles or heat pumps) which in turn will result in slightly higher consumption in the following 24 hours.

8.4.3. Grid

The country to country NTC are calculated based on the average values from the monthly or daily values of available transmission capacity. As the data provided by transparency platform by ENTSO-E (2016) is not available for all interconnections, additional data based on the NTC Matrix by ENTSO-E (2013b) has been used. When only DC interconnections between countries exist, the sum of the transmission capacity is used. Cost for transmission expansion are based on ECF (2010), who assume 1000 €/(MW*km). Here the distances between the countries' geographical centers serve as a basis for the cost calculation as we are using only one node per country. To account for investments in offshore interconnectors the "distance" between relevant countries is adjusted by hand. Furthermore new transmission capacity is allowed to be built between neighboring countries where we assume future interconnections or plans for interconnectors exist. Figure 8.6 shows the initial NTC values for 2015 in megawatt (MW).

For the PTDF approach additional data is necessary. The underlying high voltage network topology as depicted in Figure 8.7 consists of five non-synchronized high-voltage electricity grids (Continental Europe, Scandinavia, Great Britain, Ireland, and the Baltic countries) with operating voltages 150 kV, 220 kV, 300 kV, and 380 kV. This data is based on the data documentation by Egerer et al. (2014). These grids are connected by HVDC cables. The European electricity grid is originally modeled in a plant-block- and line-sharp data accuracy for all EU-28 countries as well as Norway, Switzerland and the Balkan countries. As the application in this chapter is on a country-level we use relevant aggregates of the data.

8.4.4. Time series

To adequately represent variations of demand and renewable in-feed and to determine not only the need for generation capacity and and grid, but further system flexibility options, time series spanning 8,760 hours from the year 2013 are used as a basis for

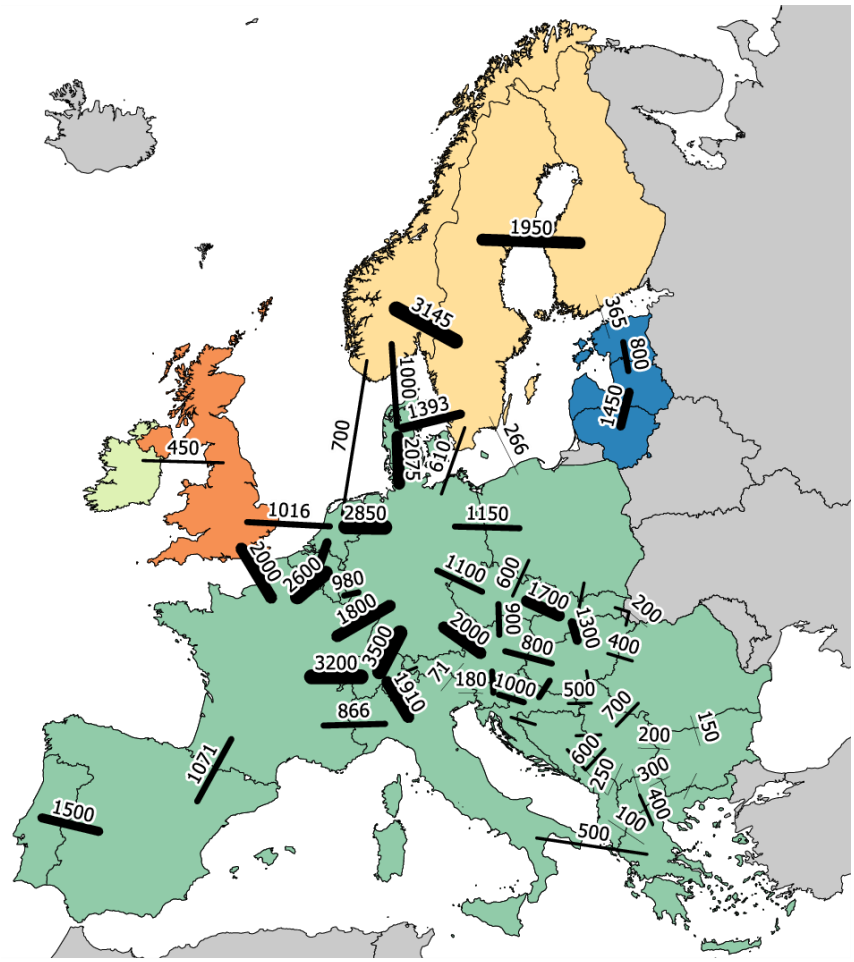


Figure 8.6.: NTC values in 2015 in megawatt.
Source: Own calculations based on ENTSO-E (2013b) and ENTSO-E (2016)

the model. As discussed earlier, not the time-series' actual value is needed in this application, but rather the spatial and temporal variation of all input parameters relatively to each other are important.

Demand time series

For electricity demand time series we use data from ENTSO-E (2014) and rescale the time series such that the average value of each country's time series is 1 before further processing. For Albania no demand time series are available. Here, an interpolation based on the time-series of neighboring countries is used.

Renewables time series

To generate renewable times series we use raw and processed data from various sources. As a basis we use meteorological data by Dee et al. (2011). We combine those

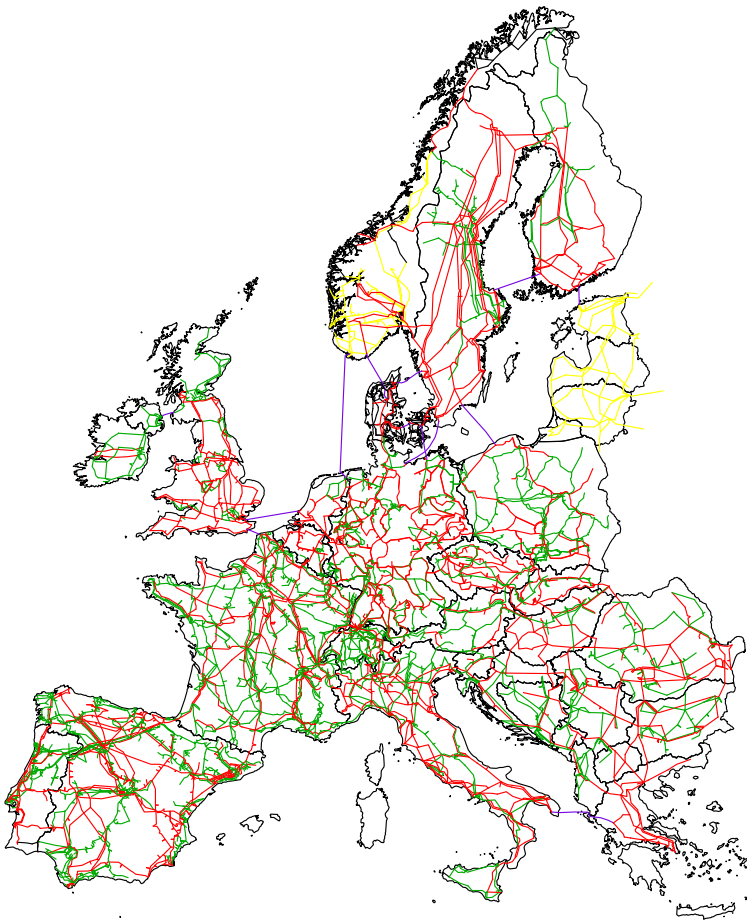


Figure 8.7.: European high voltage electricity grid in 2014
Red: 380 kV, Yellow: 300 kV, Green: 220 kV, Violet: HVDC
Source: Egerer et al. (2014)

data with Pfenninger and Staffell (2016), Staffell and Pfenninger (2016), and The Wind Power (2016) for validation. Run-of-river time series are based on ENTSO-E (2016). For Albania, Bosnia Herzegovina, Estonia, Montenegro, Serbia and Slovenia only limited data is available for run-of-river time series. Here, an interpolation based on the time-series of neighboring countries is additionally used.

8.4.5. Other

CO_2 pathway

Figure 8.8 shows the CO_2 emission pathway implemented in the default scenario. It is based on based on the scenario "Diversified supply technologies" from the European Commission's *Energy Roadmap 2050 – Impact Assessment and scenario analysis* (EC, 2011c). In this scenario and in the EU ETS more than the electricity sector

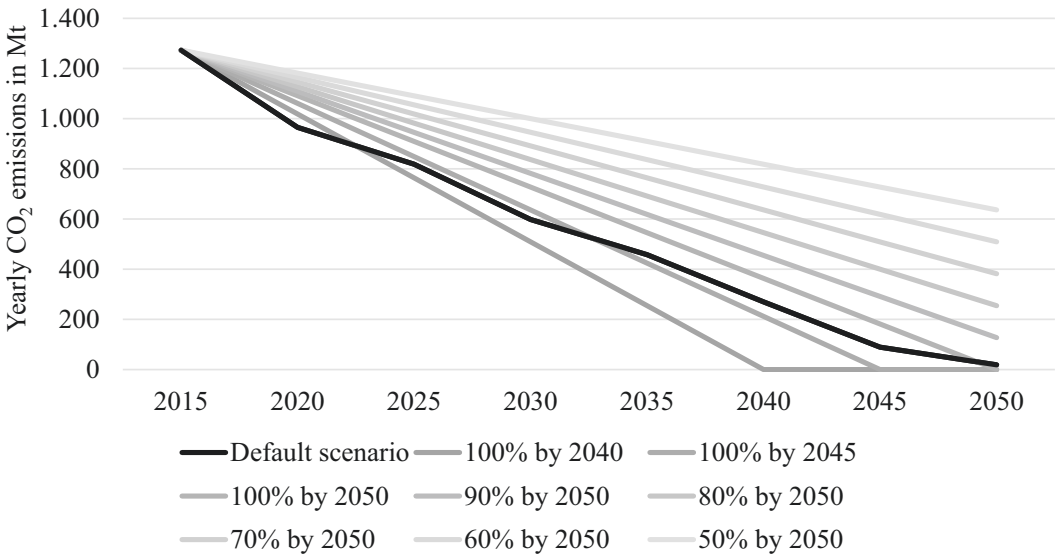


Figure 8.8.: CO_2 emissions constraints

are represented. As dynELMOD covers only the electricity sector we are using the CO_2 pathway that uses a limit on yearly CO_2 emissions designated to the electricity sector. While the overall decarbonization target covering all sectors in the scenarios currently does not include full decarbonization, the electricity sector is almost in all scenarios subject to full decarbonization. Possibly arising substitution effects can only be shown within the electricity sector. Additionally implemented CO_2 emission pathways ranging from full decarbonization in 2040 to only 50% decarbonization in 2050 are also shown in Figure 8.8.

Fuels

The development of fuel prices is important for the cost relation between gas and coal fired power plants. Prices for coal, gas and oil and their development until 2050 (Table 8.4) are based on the EU Reference Scenario 2016 by EC (2016).

Table 8.4.: Fuel prices in dynELMOD

in €$_{2013}$ per MWh$_{th}$	2015	2020	2025	2030	2035	2040	2045	2050
Uranium	3.20	3.40	3.60	3.80	4.00	4.20	4.40	4.60
Lignite	4.80	5.21	5.62	6.03	6.44	6.85	7.26	7.67
Hard Coal	4.41	6.62	7.94	8.83	8.83	9.27	10.15	10.59
Natural Gas	18.54	25.60	27.36	28.69	30.01	31.78	33.10	33.10
Oil	23.83	36.63	44.13	48.55	50.75	52.96	55.17	56.49
Biomass	8.10	9.00	9.90	10.80	11.70	12.60	13.50	14.40
Waste	8.10	9.00	9.90	10.80	11.70	12.60	13.50	14.40

Source: EC (2016)

8.5. Time series reduction

As long-term generation capacity investment models can become computationally challenging, calculations with a large number of hours are not feasible. In the investment determination step of dynELMOD the model is not solved for the time span of 8,760 hours of a whole year, but a reduced time-series is used. As we want to represent the characteristics of all time-varying input parameters, on the one hand the highly multidimensional dataset with temporal as well as spatial variations need to be represented accordingly. The model hour selection is a key assumption in such a modeling exercise. A wrong selection of time-series can lead to a distorted model outcome and a power plant portfolio that either has too much, too little, or a wrong mixture of electricity generation capacities when the model outcome is tested with a full time-series.

Recently, Poncelet et al. (2014b, 2016) quantified the effect of temporal as well as operational detail in a long-term planning model. The authors find, that a good temporal representation should take preference before implementing further operational constraints, when computational limitations are reached.

8.5.1. Previous work

In the literature, several time series reduction techniques exist. Most approaches focus on selecting a representative set of hours or days from given time-series using hierarchical or parametric clustering methods or approximating time-series characteristics e.g. using a MILP.

Clustering methods such as k-means or hierarchical clustering are often used options to extract clustered data from a time series. Green et al. (2014) use k-means to extract relevant sets of demand profiles for the British electricity system. An application to an investment problem with k-means time slice clustering is shown in Munoz et al. (2016). Nahmmacher et al. (2016) develop a new time slice selection approach. Temporal and spatial variation of time-series is reduced using a hierarchical clustering of representative days. The reduced time-series are tested using the LIMES-EU model (Nahmmacher et al., 2014). The authors show that “Six representative days are sufficient to obtain model results that are very similar to those obtained with a much higher temporal resolution” (Nahmmacher et al., 2016, p. 441). Després et al. (2017) analyze the demand of electricity storage given high levels of RES in the European electricity system using POLES (Prospective Outlook on Long-term Energy Systems). The authors also use the hierarchical clustering algorithm developed by Nahmmacher et al. (2016) with twelve representative days to capture the variability of the time-series.

Other approaches often involve the use of a MILP, to select hours given an optimization problem, to minimize the distance between the original and reduced time series. Van der Weijde and Hobbs (2012) sample 500 hours from 8,760, trying to match the original dataset, by minimizing the difference between the original time series and the reduced time series with regards to correlations, the averages as well as standard deviations of all model regions. Poncelet et al. (2015) select representative days using a MILP that also optimizes criteria based on the original time series. The authors find that the number of representative days is more important for the model result robustness, than the hourly resolution of the reduced time series, which is set at a 4-hourly interval.

De Sisternes and Webster (2013) select a number of weeks based on a given time-series by minimizing the quadratic difference between full and the reduced net load duration curves. This approach could also be applied to renewable feed-in time series. Due to limits in implementation, only five weeks can be selected using this approach.

In Integrated Assessment models the correct representation of variability of wind gains importance, as usually the hourly representation is highly aggregated and cannot reflect renewable and load variability (see Pietzcker et al., 2017). Ueckerdt et al. (2015) also use the residual load duration curve as in their approach. Here, a stylized residual load duration curve is approximated, which changes form depending on the amount of renewables introduced into the system. The authors demonstrate the effects using the REMIND-D model.

8.5.2. Our time series reduction approach

During the development of dynELMOD, the aim of the to-be-applied time frame reduction method was not only to represent the general characteristics of the full time series but also to achieve a continuous time series that also captures seasonal variations in a satisfactory manner. The approach should also preserve seasonal characteristics in the right order within the year. It is of particular importance to approximate the behavior of hydro reservoirs, where not only hourly dispatch occurs, but also the yearly cycle of inflows and the filling level plays a role over the course of a whole charging cycle, which is often an entire year. The amount of inflow in reservoirs should also be met. Especially since the seasonal variation of hydro inflows and reservoirs needs to be captured adequately and in the right order, we develop an own time reduction methodology described in this section.

The aim is to meet as many characteristics of the full time-series in the reduced time-series as possible while still achieving a manageable model size. This includes the time-series'

- daily variation structure;

- seasonal structure;
- minimum and maximum values to capture a wide range of possible situations;
- average, or for renewables the estimated full load hours given in the data;
- "smoothness" or hourly rate of change characteristic, as otherwise the need for flexibility options such as storage and ramping might be under- or overestimated.

For input time-series where only monthly data is available (e.g. aggregated generation amounts for run-of-river plants), the approach should also be able to treat the time series accordingly, that no "jumps" at the month's borders are present in the final time series.

When using a reduced time-series, occasionally occurring periods of low wind and solar in-feed need to be represented as well in the time series. Especially weather phenomena like simultaneous low wind in-feed over the whole model region for a longer time need to be accounted for. If not implemented, an overestimation of the reliability of renewable generation capacities occurs, which results in an inadequate generation portfolio with provides an infeasible generation pattern in the full calculation.

The time-series reduction process is done according to the following steps:

1. Hour selection
2. Time series smoothing
3. Time series scaling

1. Hour selection The first step consists of selecting hours that will be processed further. As a continuous development of the time series is wanted, the ordering of hours will be kept as is. Selecting an hour selects all occurrences of the multidimensional dataset, e.g. the data of renewable availability and demand for all regions will be chosen, to keep the relationship within the data structure intact. From the time series of a full year we select a subset of hours for further processing. We use a interval, determined by the desired time granularity to reach a continuous function that captures daily and seasonal variation.

In the standard case we use every 25th hour of the full time series, corresponding to an N of 1, which results in a shortened time series of 351 hours. In the full calculation with 8,760 hours all hours are selected. The nth hourly selection can start at all hours of the day, which gives an opportunity to test the smoothing procedure with multiple input values. In the standard case we use the 7th hour for the start of the selection.

To guarantee a robust model result extreme events have to be taken into account as well. Investment models using a time reduction technique tend to overestimate the

firm capacity of renewables, and in combination with storage, the model's investment decision could lead to an adequate electricity generation portfolio. Therefore we include the hours with the lowest feed-in of solar and wind into the time set, to better represent periods of low renewable feed in. The numbers of hours we include in the time set are dependent on the total calculated hours. In the standard case (a time set of 351 hours) we additionally include the 24 consecutive hours with the lowest renewable infeed. If the time set is reduced to 174 hours we only include 12 hours. These values have been derived using iterative testing on a wide range of scenarios, to neither over- or underestimate the effect of low renewable availability.

2. Time series smoothing The resulting time series of step 1 is interpolated as a continuous time series. This reduced time-series' variations are now much higher than the original time series, as day-to-day variations are now referred to as hourly variations. The next step smoothes the shortened time series. Thus artifacts can be removed by smoothing the series using a moving average function. The width of the moving average windows is specified by hand for each type of input data and length of the reduced time frame. The goal in trying to determine the window size is to keep the time-dependent characteristic in place and meeting the time series' variation target. In the full dispatch calculation with 8,760 hours no smoothing takes place except for data that is provided in a monthly resolution to reduce monthly "jumps" in the time series.

3. Time series scaling In step 3, the time series is scaled according to the targets mentioned above. Equations (8.38) to (8.40) describe the optimization problem used in the scaling process. It is solved as a discontinuous non-linear program (DNLP) using the solver CONOPT.

The objective value obj used in (8.38) determines the difference between the $target$ and reached average sum of the time series. The equations (8.39) and (8.40) enforce that the scaled time series reaches the target minimum and maximum values $mintarget$ and $maxtarget$. For RoR, solar PV and wind, the time series contains values between zero and one, with the target corresponding to the anticipated full load hours. Load time series have an average of one, here the minimum and maximum values determine the maximum upward and downward deviation from the average load. The term $\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}}$ scales the given time series to values between zero and one. These values are transformed using the power A to reach the required shape, while keeping the minimum and maximum values of the time series intact. The Variables B and C move and scale the time series to reach the desired minimum and maximum values. As the variables B and C can be determined independently from A, a model containing a dummy objective as well as the equations (8.39) and (8.40)

is solved first, then the variables B and C are fixed, and the model containing the equations (8.38) to (8.40) is solved.

$$\min obj = \left(target * T - \sum_{t \in T} \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \right)^2 \tag{8.38}$$

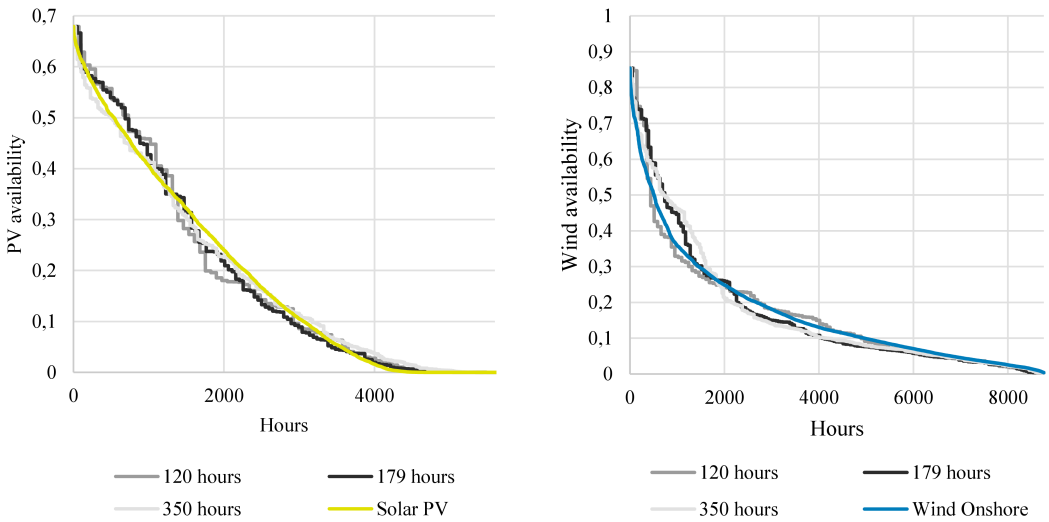
$$mintarget = \min_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{8.39}$$

$$maxtarget = \max_t \max \left(0, \left(\frac{sts_t - sts^{min}}{sts^{max} - sts^{min}} \right)^A * B + C \right) \tag{8.40}$$

After finishing this step, all relevant time-dependent input parameters can be calculated and put into the model.

8.5.3. Time series reduction results

This section shows the result of the time frame scaling process for selected cases and parameter variations, using German time-series data. First, we show that the approach is able to approximate the relevant duration curves, then the smoothness of the original and reduced time series is compared, and the full time series that is used in the model is shown.

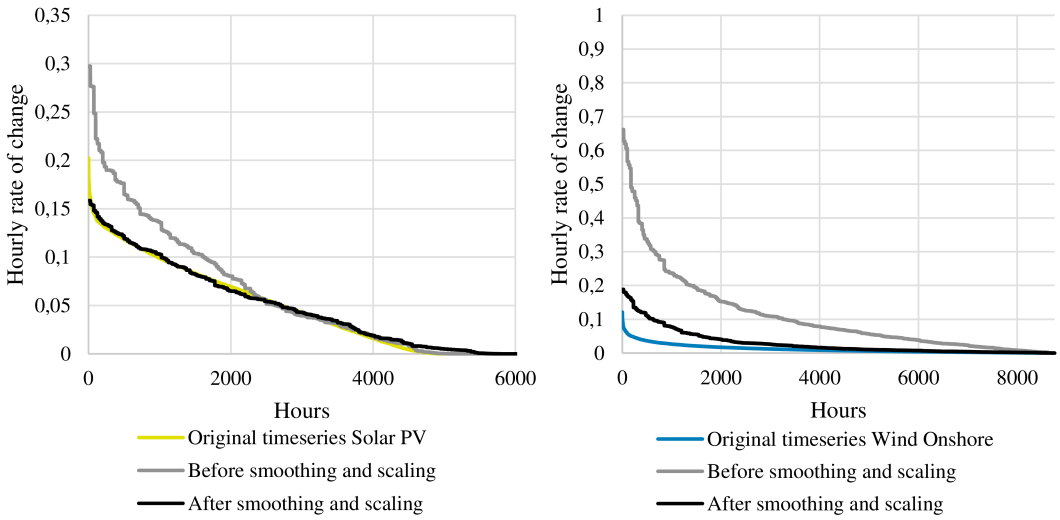


(a) Solar PV infeed duration curve (b) Wind onshore infeed duration curve

Figure 8.9.: Original and processed load and infeed duration curves

Figure 8.9 shows German solar PV and Wind onshore duration curves for the original time series as well as the resulting duration curves after the scaling process

for different numbers of model hours. With a low number of model hours the original duration curve is not adequately approximated, but the model hours in this application (179 or 351) show good results. When a very low number of model hours is used the approximation worsens, but works sufficiently well for using the model with a smaller number of hours for quick tests.



(a) Solar PV (b) Wind onshore

Figure 8.10.: Time-series rate of change

The time series' sorted gradients are displayed in Figure 8.10. The original time series rate of change is overestimated before the smoothing process takes place, after smoothing and scaling a very good representation for solar PV is achieved. The approximation of the rate of change for wind also increases substantially, but is still slightly higher than in the original time series. This slightly overestimates fluctuation of wind in-feed.

Figure 8.11 shows example results of the time frame reduction technique for load, onshore and offshore wind and solar PV from German time series. Here, every 25th hour is used, the first included hour of the original time series is 7. The FLHs of the renewable time series have not been changed from the original input time series. In the actual calculations the FLH are adjusted to the expectations of the technological development in the future. Seasonal variation as well was the daily profile of solar PV and load are represented well, the onshore and offshore wind time-series also show seasonal as well as typical daily fluctuations.

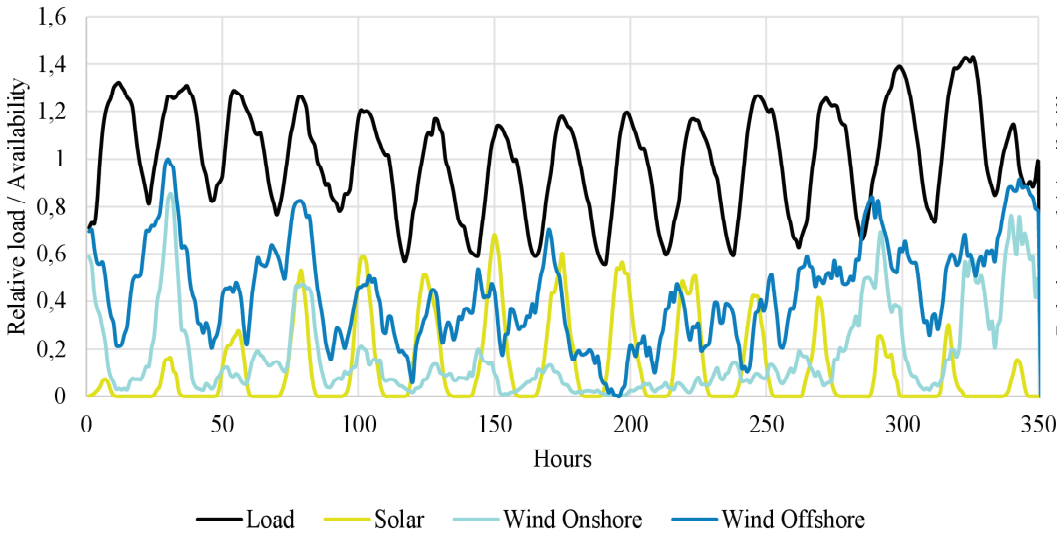


Figure 8.11.: Example time series reduction results

8.6. Results

The model results of dynELMOD provide insights into the driving forces for the future development of the European electricity sector. As the solution space is constrained by and a result of many factors such as the emission limit, capacity expansion restrictions, time related input factors such as renewable availability and assumptions about the development of costs for investments and fuels. The model outcomes analyzed in this section are the electricity generation capacity development, the resulting hourly generation dispatch, CO_2 emissions, and flows between countries.

8.6.1. Investment and generation results in the standard scenario

Figure 8.12 shows the development of the installed capacities from 2015 to 2050 in Europe. The installed capacities increase substantially from 980 GW in 2015 to 2,870 GW in 2050. At the same time, the European generation portfolio is transformed from mainly fossil fueled generation technologies to renewable generation technologies. The switch to renewable generation capacities, which usually have lower FLH, induces this overall capacity increase. In 2050 we mainly see 870 GW of solar PV and 740 GW wind onshore capacities accompanied by 270 GW of Wind offshore. No new nuclear, lignite, or hard coal fired capacities are installed which result in a nearly complete phase-out for those technologies until 2050.[85] Investments in natural gas fired power

[85] Sensitivity analyses show that investments into nuclear capacities are observed at or below overnight costs of 4,000 €/kW.

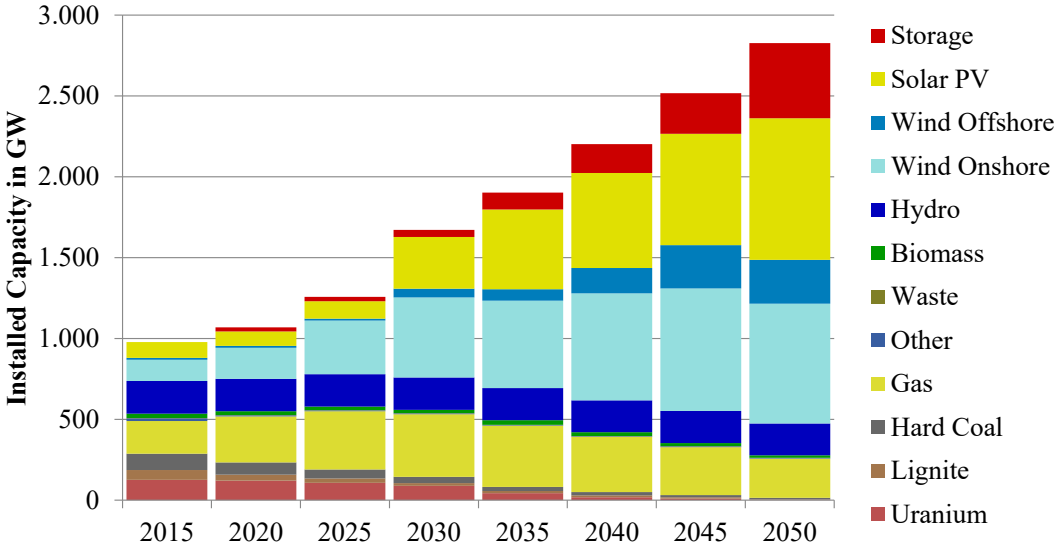


Figure 8.12.: Installed electricity generation and storage capacities in Europe 2015–2050

plant capacities take place. Their capacity in 2050 reaches 215 GW. These capacities mainly serve as backup capacities with very low yearly usage factors. Just over half (52 %) of these capacities are located in France, Germany, and the United Kingdom.

Over the years the total investments in generation capacities per year gradually increase from 40 GW per year in 2020 to 120 GW per year in 2050. From 2030 onwards these investments are primarily in wind and solar PV. The investments into storage increase until 2050, where they nearly make up a third of the total new investments. This results in a total of 465 GW storage which includes batteries, power to gas and DSM.

In line with the development of the generation portfolio, the electricity mix changes as shown in Figure 8.13. The electricity generation increases from 3,307 TWh in 2015 to 4,018 TWh in 2050. Despite the fact that in 2015 still two thirds of the electricity generation in Europe is conventional in 2030, already half of the total electricity generation is renewable. This trend continues until 2050 where more than 95 % of the electricity generation is renewable. In 2030 onshore wind power replaces gas fueled power plants as the main source of electricity for Europe with a share of more than one quarter. Until 2050 the share of offshore wind and solar PV reach also one quarter, while onshore wind stays the biggest producer with more than one third of the electricity production. While solar PV and offshore wind have similar production volumes, their installed capacity varies significantly due to their different FLH. Despite the solar PV's lower FLH, is still competitive due to its very steep cost per kilowatt (kW) decrease over time.

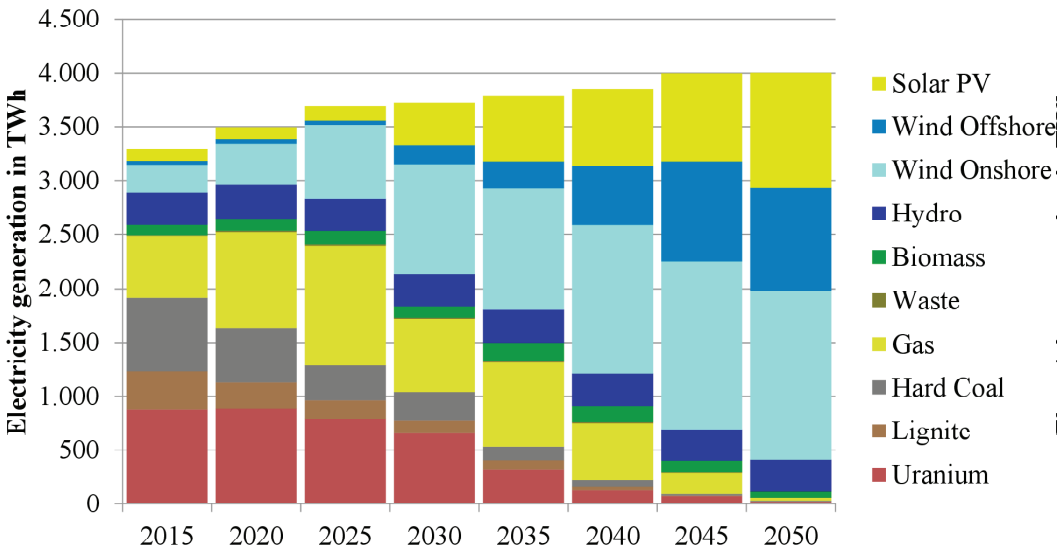


Figure 8.13.: Electricity generation 2015–2050

Figure 8.14 show the composition of the total CO_2 emissions in the European electricity sector over time. The amount of available emissions is limited by the CO_2 pathway (see Figure 8.8). Emissions decrease from 1,129 Mt CO_2 in 2015 to 18 Mt CO_2. Electricity from coal is the primary source of CO_2 emissions until 2030. As the coal phaseout occurs earlier, gas becomes the main emitter afterwards. Emissions from hard coal and lignite gradually decline from 2015 onwards until nearly zero in 2045. In contrast, emissions from gas remain stable until 2040.

The development of the implicit CO_2 price is shown in Figure 8.15. It is determined using the shadow price on the emission constraint in the model, and reflects the marginal savings of relaxing the constraint by 1 t CO_2, thus giving an indicator about the price of 1 t CO_2. Conforming with today's EU ETS, the price is very low in 2015 and in the first following periods. When the emission constraint tightens, the price increases substantially, reaching a high of 177 €/t in 2050. As only the electricity sector is included in detail in dynELMOD, interactions with other EU ETS sectors might lead to different results, when included.

8.6.2. Grid

A further source of flexibility in the electricity system can be provided by increasing cross-border interconnection capacity, which provides a comparatively low-cost solution to decrease the effect of spatial variability of demand and supply. Given sufficient transmission capacity, regionally distinct generation portfolios can complement each other, leading to an overall decrease on electricity system costs. Grid expansions in dynELMOD are represented as an increase in available NTC capacity (both in the

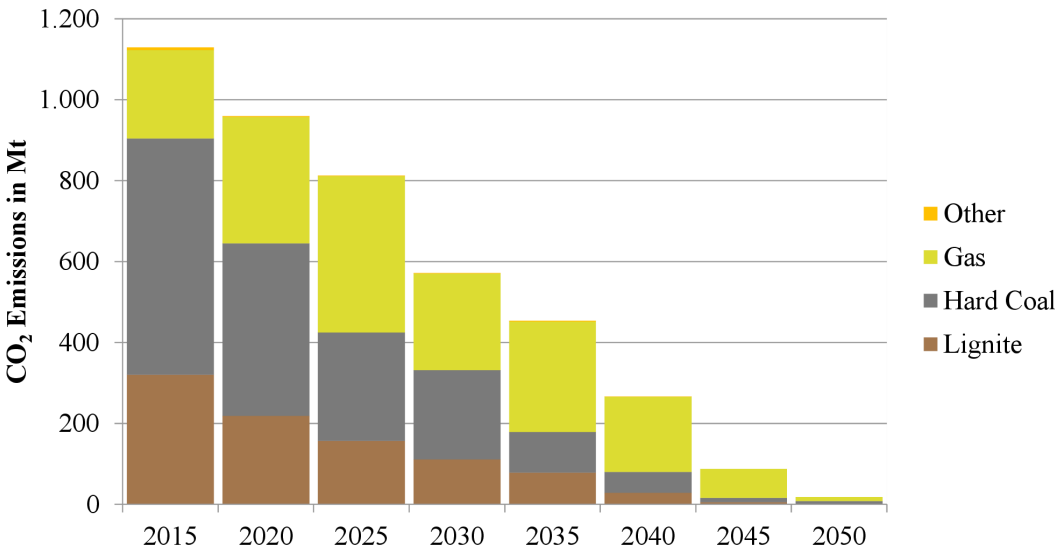


Figure 8.14.: CO_2 emissions by fuel 2015–2050

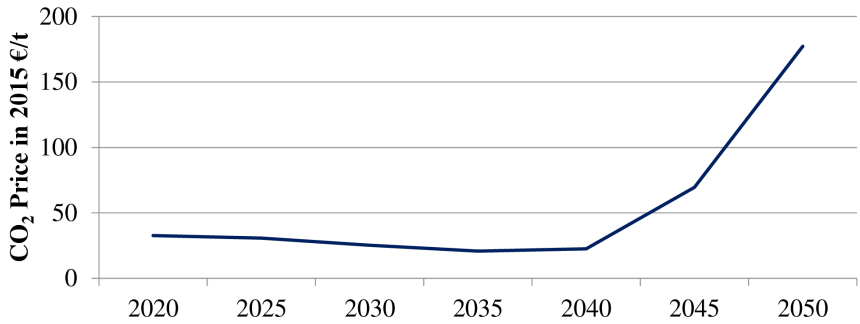


Figure 8.15.: CO_2 Price development 2015–2050

NTC as well as the flow-based approach). The final NTC values of the year 2050 are shown in Figure 8.16.

We observe a trend for transmission capacity expansion stretching out from the south (with high solar potentials) and the west (long coast line with high wind potentials) towards central and eastern Europe. France has an important position for these pathways as it connects the south and west to the central east. Accordingly the highest cross-border grid expansion is observed between France and Spain. Here, the high potential for solar PV as well as wind potential drives the need for increased interconnection between the Iberian peninsula and the rest of continental Europe. Analogous the interconnection between the United Kingdom and France (and the Benelux) is fortified to account for the high onshore and offshore wind potentials in the British Isles. Furthermore the interconnectors between Germany and Denmark and also Denmark and Sweden are expanded intensively. This creates a corridor from central Europe to the dispatchable hydro and storage potentials of northern

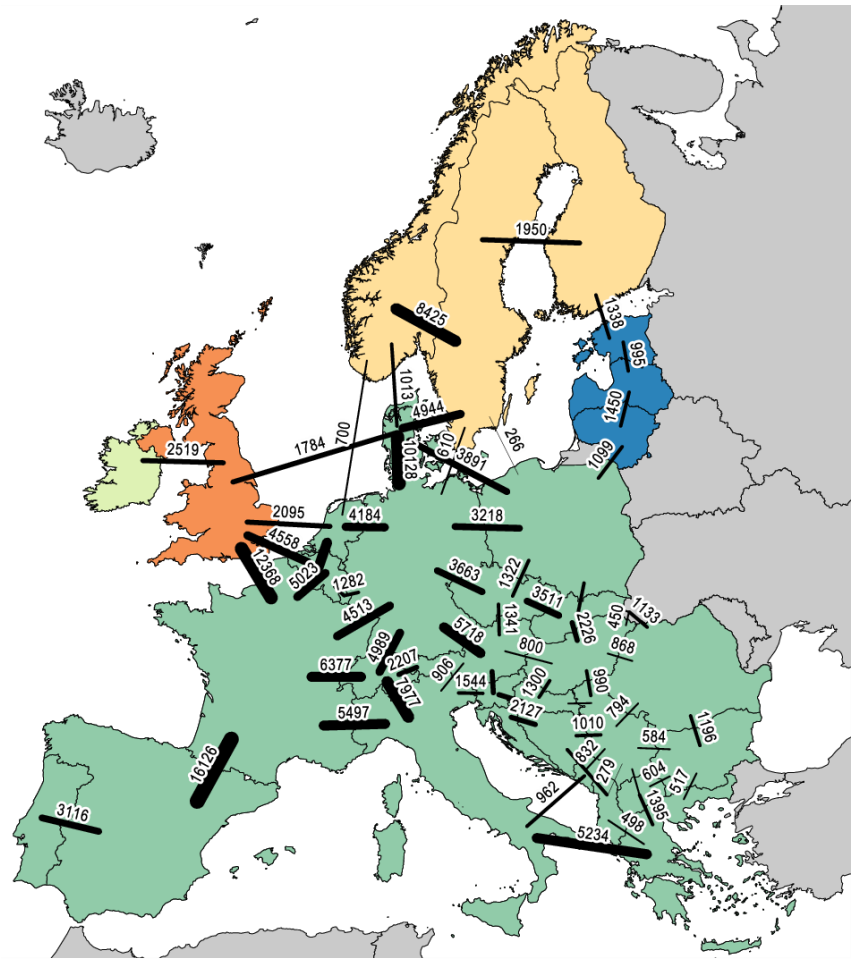


Figure 8.16.: NTC values in the year 2050 in MW

Europe. Besides these corridors, the interconnection between Italy and Greece is strengthened which results in a closed ring in the Mediterranean. To our surprise, the interconnector between Norway and Germany (which exists as an option for the model to be built) does not materialize. Also the interconnector between Sweden and Lithuania is not built.

The increased transmission capacities described in the previous paragraph allow for intensified electricity exchange between countries. Figure 8.17 depicts the sum of flows on the countries' borders in terawatt-hours (TWh). Once more we observe the expected general picture of electricity flowing from (north) west and south towards central (east) of Europe. This aligns with the transmission corridors depicted in 8.16. The countries in (north) west and the south export electricity due to their relative cost advantage in the production of electricity from wind and solar PV. The countries in central east import this electricity. Our results show that in comparison to the situation of 2015, Germany undergoes the largest overall change, as it will turn

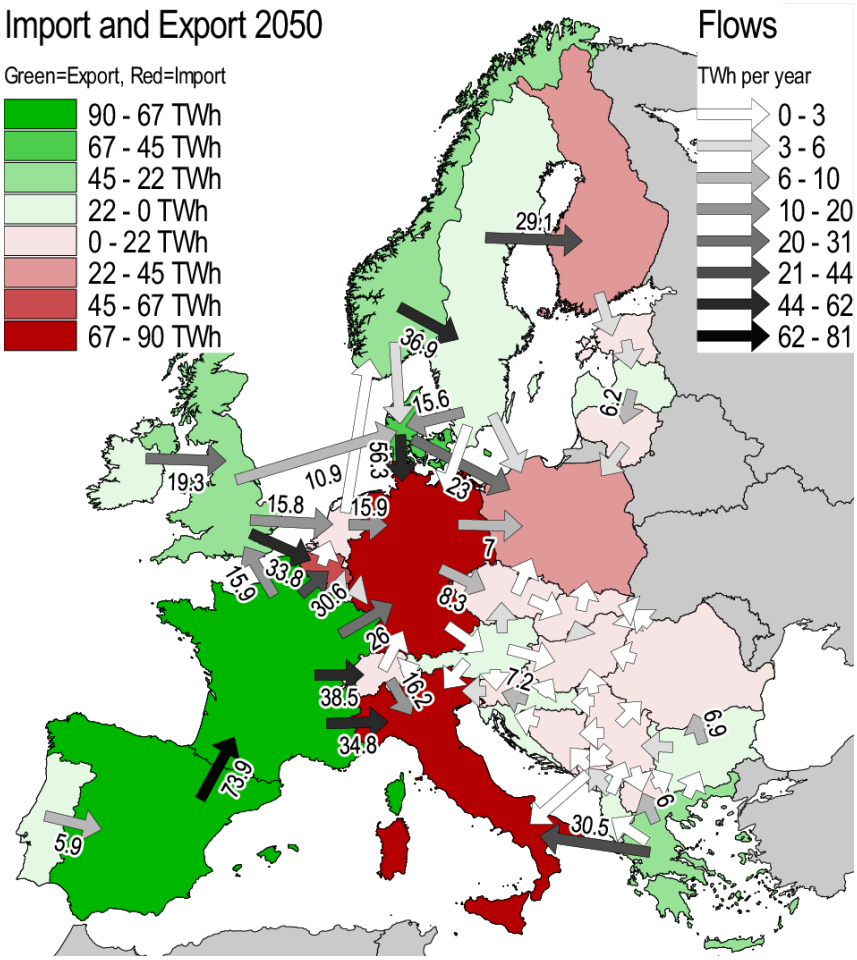
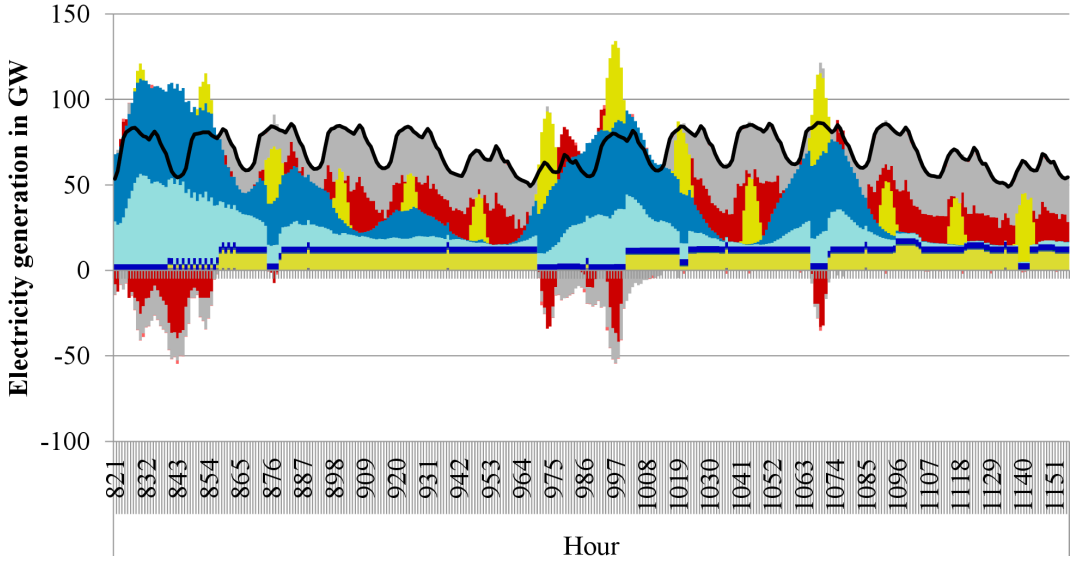


Figure 8.17.: Import and export in TWh in the year 2050

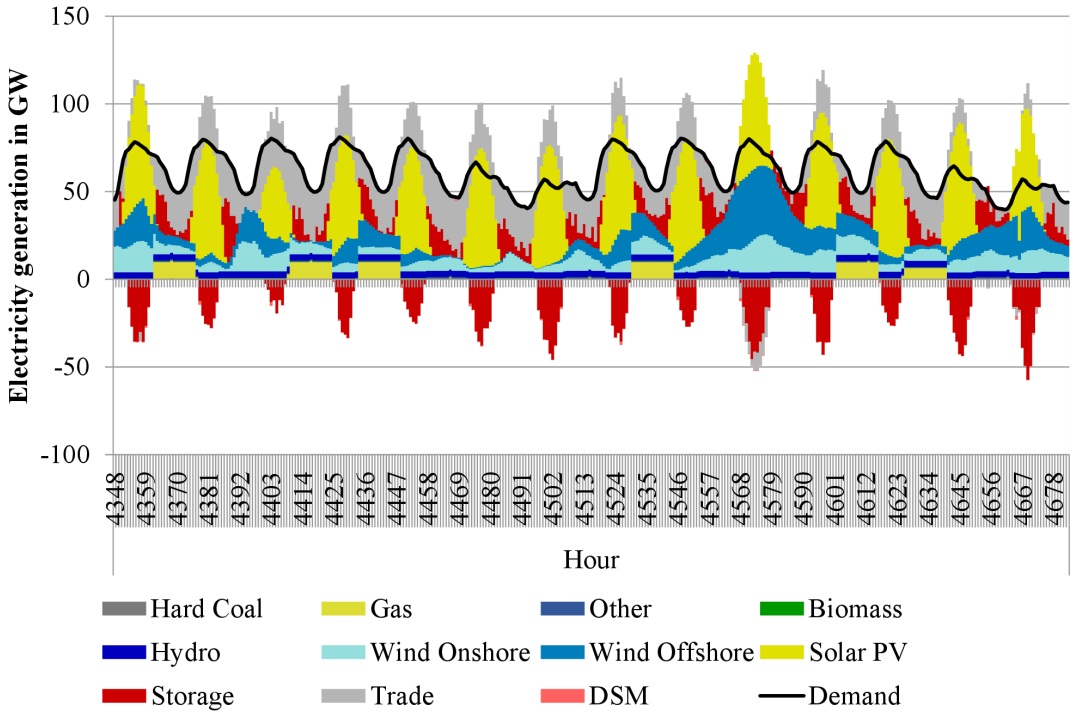
from an exporter to Europe's second largest importer. Although also in Germany substantial investments in renewable electricity generation capacities take place, dynELMOD suggests imports as a low-cost option. Import and exports in south east Europe seem balanced. As the demand and generation in this region is generally lower, small flows can result in substantial import or export shares for single countries.

8.6.3. Detailed dispatch results for selected countries

We analyze the hourly dispatch results for two consecutive winter and two consecutive summer weeks of 2050 in this section. The winter weeks are in early February (weeks 5 and 6) and the summer weeks are in early June (week 25 and 26). These weeks are characterized by low wind feed-in (in Germany) to show a situation when not necessarily enough conventional and renewable capacity is available. This is the case especially in winter, when solar radiation is reduced.

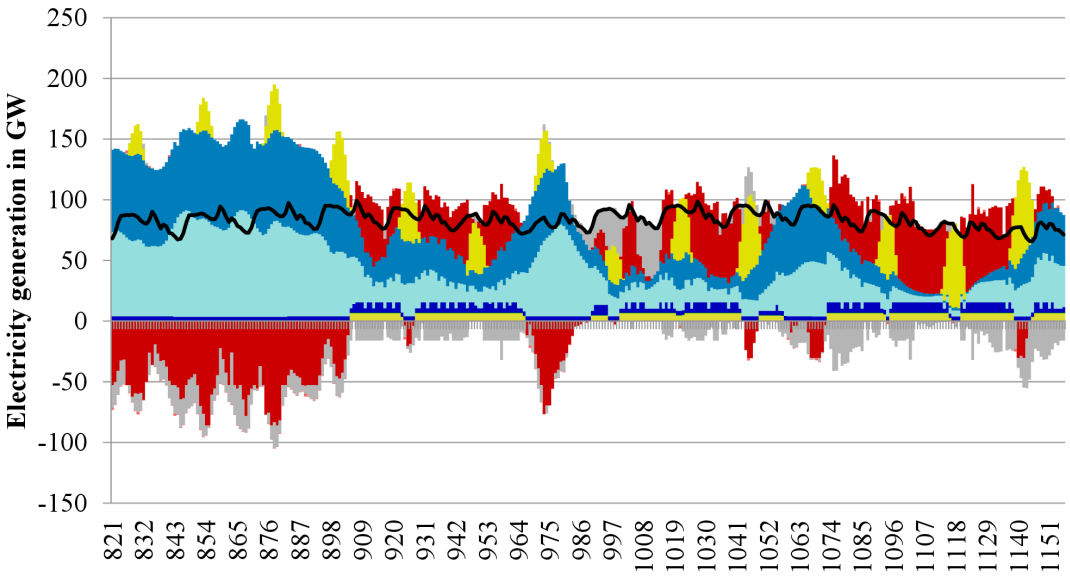


(a) Dispatch in Germany winter 2050

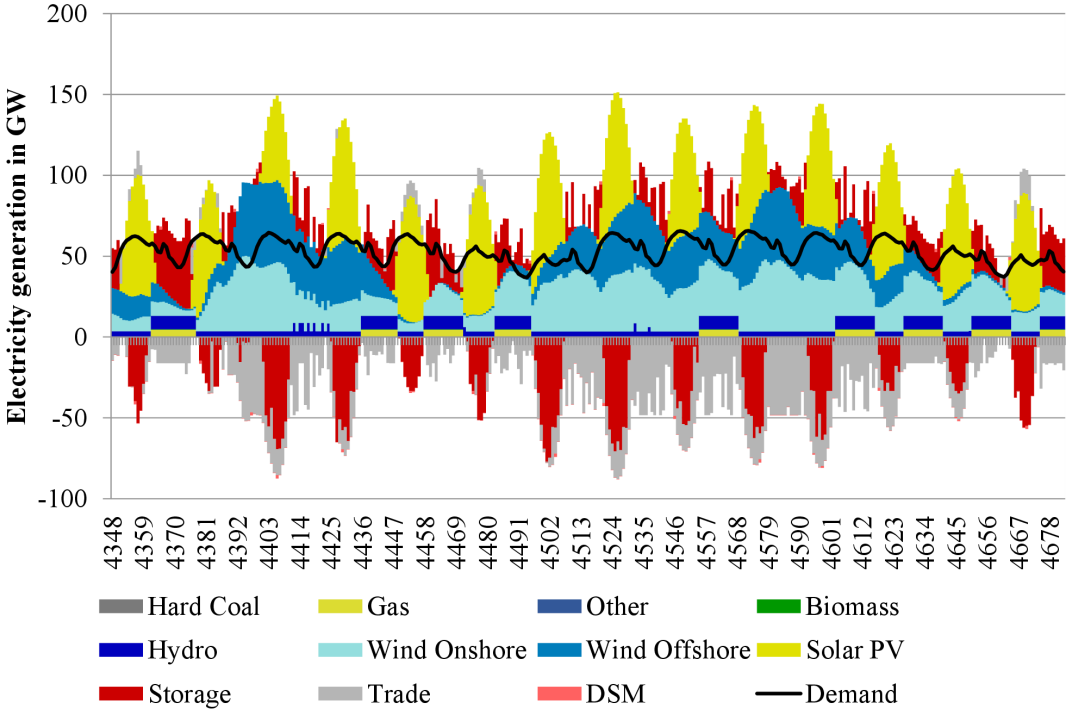


(b) Dispatch in Germany summer 2050

Figure 8.18.: Dispatch in Germany in the year 2050



(a) Dispatch in France winter 2050



(b) Dispatch in France summer 2050

Figure 8.19.: Dispatch in France in the year 2050

In Figure 8.18 we observe that Germany imports for most of the time in the selected winter and summer weeks. Exports occur only when there is high wind feed-in. In the summer an interesting storage charging pattern occurs, where electricitiy is imported while electricity is stored at the same time. Here, excess electricity from other countries is used to charge the storage technology power to gas, which is characterized by long seasonal cycles. This allows for more storage discharging than charging in the winter weeks and vice versa in the summer. Power to gas is mainly discharging during winter time and charging during summer time. Thus, during the winter weeks only batteries and DSM contribute to storage demand, to balance out daily fluctuations, while during the summer weeks storage discharge comes only coming from batteries and DSM. During the combination of low wind and low solar radiation the German system will be supported by conventional backup capacities.

Comparing the German dispatch to the dispatch in France (Figure 8.19) shows that France is exporting most of the time. Especially in the summer when there is high wind and solar feed-in up to 50 GW are exported in peak hours. Furthermore, the storage charging and discharging is much more balanced within the two weeks. Hence we see less usage of seasonal but mainly daily storage activities.

Large scale weather phenomena are particularly important for the dispatch, as they can affect wide regions, with simultaneous very low or high availability of renewables. The system needs to be adequately prepared for either high in-feed (by means of curtailing in-feed) or low in-feed by means of providing sufficient backup capacity or large enough storage capacities. One example of a wind front moving between countries can be seen in the winter weeks. When we compare the wind feed-in in Germany and France we can observe that while the shape seems similar the timing and peaks of the feed-in is shifted by several hours. The wind front in the beginning of the first winter week lasts about a day longer in France than in Germany.

In both model runs, during the investment step as well as the dispatch step with 8,760 hours, the infeasibility variables are not used by the model. The run with 8,760 hours shows that during the investment phase an adequate electricity system configuration has been obtained.

8.6.4. Varying the inputs and calculation options

CCTS availability

In the results shown previously, the availability of CCTS was restricted, as we intended to do the calculations with technologies that are available for large scale applications today. Assuming commercial availability of CCTS, as well as solutions for the issues around storing and transporting the resulting CO_2, we include this technology in

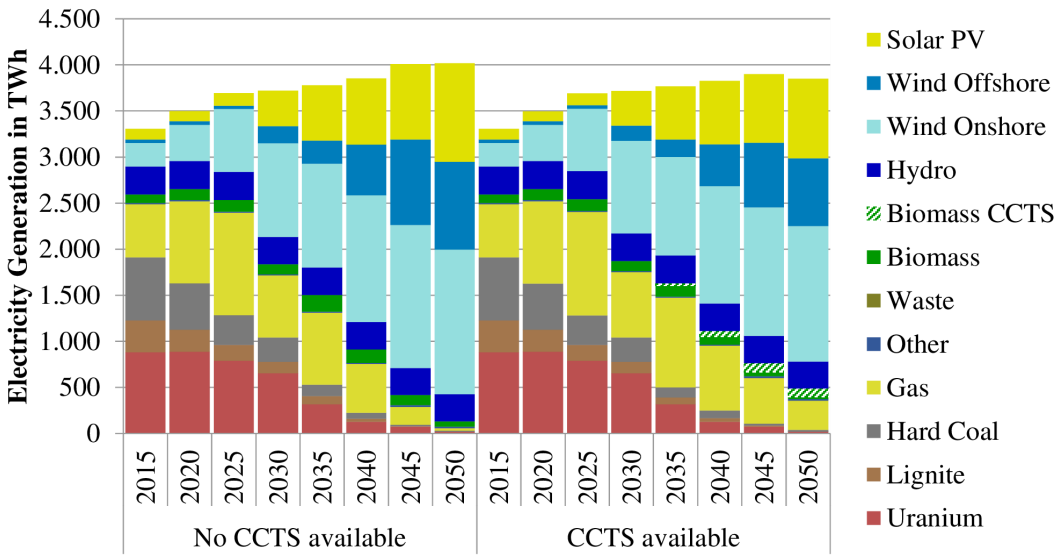


Figure 8.20.: Generation depending on CCTS availability

dynELMOD as a sensitivity. Thus, we allow for several technologies with CCTS to be built. This includes Lignite CCTS, Coal CCTS, two gas-fired CCTS technologies and Biomass CCTS. With availability of these technologies, the investment decision will vary especially when high GHG mitigation pathways are implemented.

Figure 8.20 shows the development of electricity generation in Europe with the availability of CCTS. We see that no additional gas-fired CCTS generation is built. Starting in 2035 when the emission constraint tightens additional Biomass CCTS and gas-fired electricity generation is observed, as Biomass CCTS capacities are built, which in turn enable higher generation from gas. Compared to the standard scenario, this reduces the generation of mostly renewable capacities such as Wind Onshore and Offshore, and Solar PV. As the CCTS capacities are dispatchable and have a higher average availability than renewables, the need for storage capacities is also decreased. The total amount of capacities that are fueled by Biomass increases slightly. Biomass CCTS capacities provide a way to achieve negative emissions, giving the other fossil conventional capacities some leeway to reduce their output in later time steps. The overall electricity generation is lower than in the case without CCTS, as storages see less use, and fewer storage losses occur.

In Figure 8.21 the development of electricity generation with CCTS over time is depicted. Most of the additional generation is based on biomass, accompanied by increased gas fired generation in 2045 and 2050. The additional gas-fired generation roughly corresponds to three times the additional biomass fueled generation, as these lead to an assumed emission reduction.

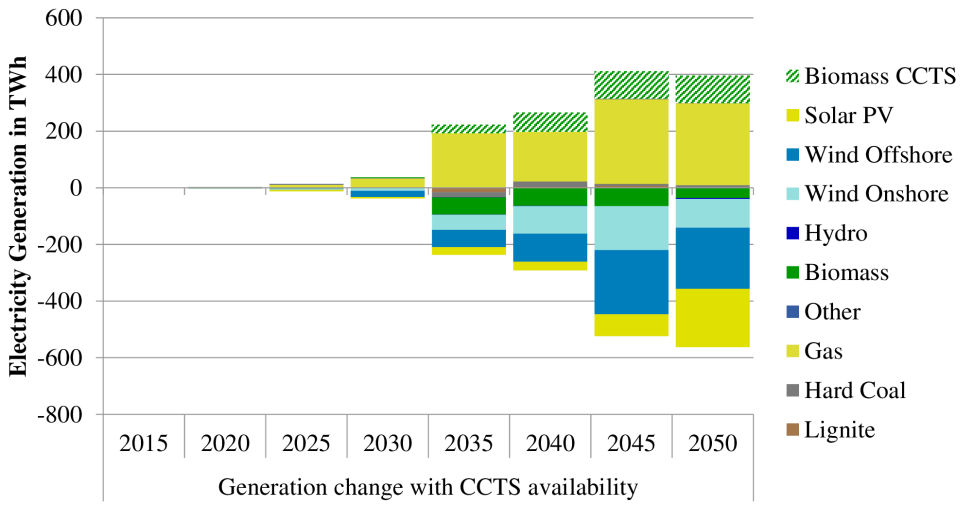


Figure 8.21.: Difference in electricity generation with CCTS available

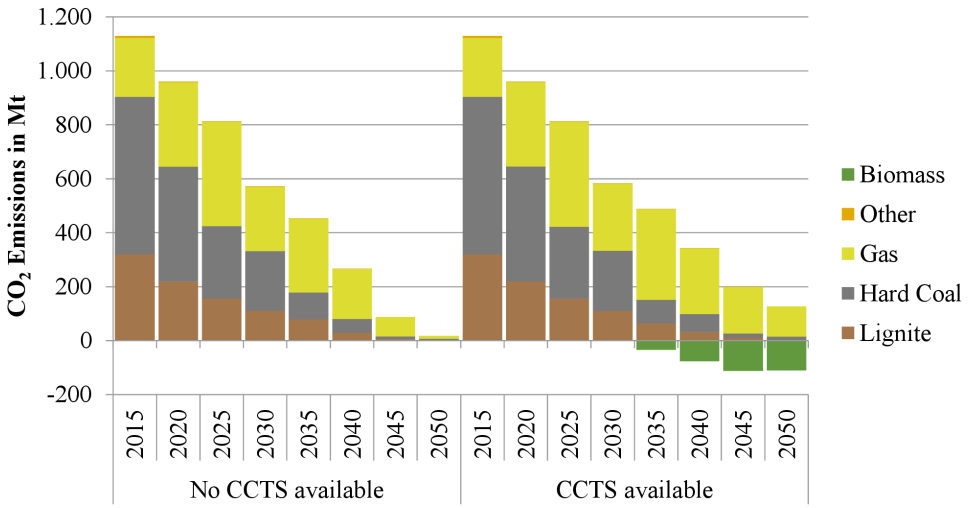


Figure 8.22.: Emissions depending on CCTS availability

In the Figure 8.22 the emissions by fuel are shown. The adoption of biomass fueled CCTS starts in 2035, and reaches its maximum in 2045. This development enables conventional gas-fired power plants without CCTS to run while not violating the total yearly emission constraint.

Emission constraint implication

One of the main constraints driving the results is the decarbonization target. A goal of reaching a nearly emissions free electricity system implies major changes to the underlying electricity generation portfolio as well as other infrastructure providing flexibility such as storage and grid. In this subsection a sensitivity analysis tests the effect of altering the decarbonization target to gain insights what outcomes could arise

when decarbonization takes place earlier or is not implemented until 2050. Starting from 2015, linear CO_2 emission pathways have been implemented (see Figure 8.8), which range from only reaching 50% decarbonization of the electricity sector until 2050 to zero emission already in 2040.

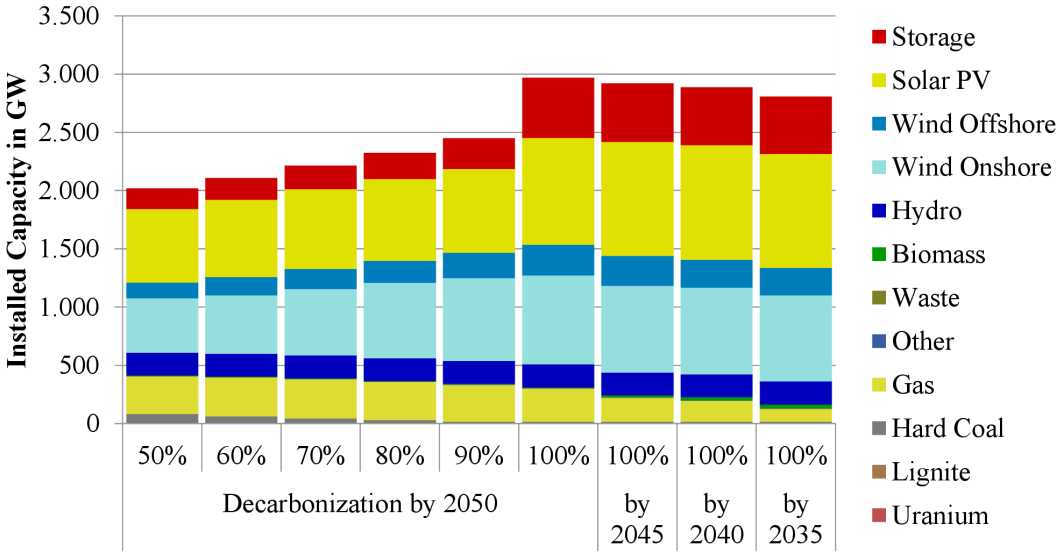


Figure 8.23.: Installed capacity 2050 subject to the decarbonization target

Figure 8.23 shows the installed electricity generation capacities in 2050 depending on which CO_2 emission pathway has been implemented. In the cases where only 50% decarbonization is reached until 2050, the capacity needed is lower than in the standard case, as a higher amount of electricity generated comes from fossil fuels (mainly gas, only 78 GW of hard-coal capacities). Renewable power sources play a significant role even in the 50% decarbonization pathways, as the future cost development leads to widespread implementations regardless of scenario. In the case of 90% decarbonization, the installed capacities are highest, as here both gas-fired capacities for the transition years as well as sufficient renewable capacities to reach 90% decarbonization in 2050 are built. With stronger targets for 2050 or earlier decarbonization, the amount of renewable plants installed in 2050 are similar, but fewer gas-fired plants exist, as these are not needed during the transition years.

Grid representation approach

In addition to the flow-based cross border grid representation approach, the option exists to using a simplified grid representation, which implements the cross-border flows as a transport model. The so-called “NTC approach” has the advantage of substantially faster calculation times as well as lower data requirements. This section presents the grid expansion results of the NTC approach.

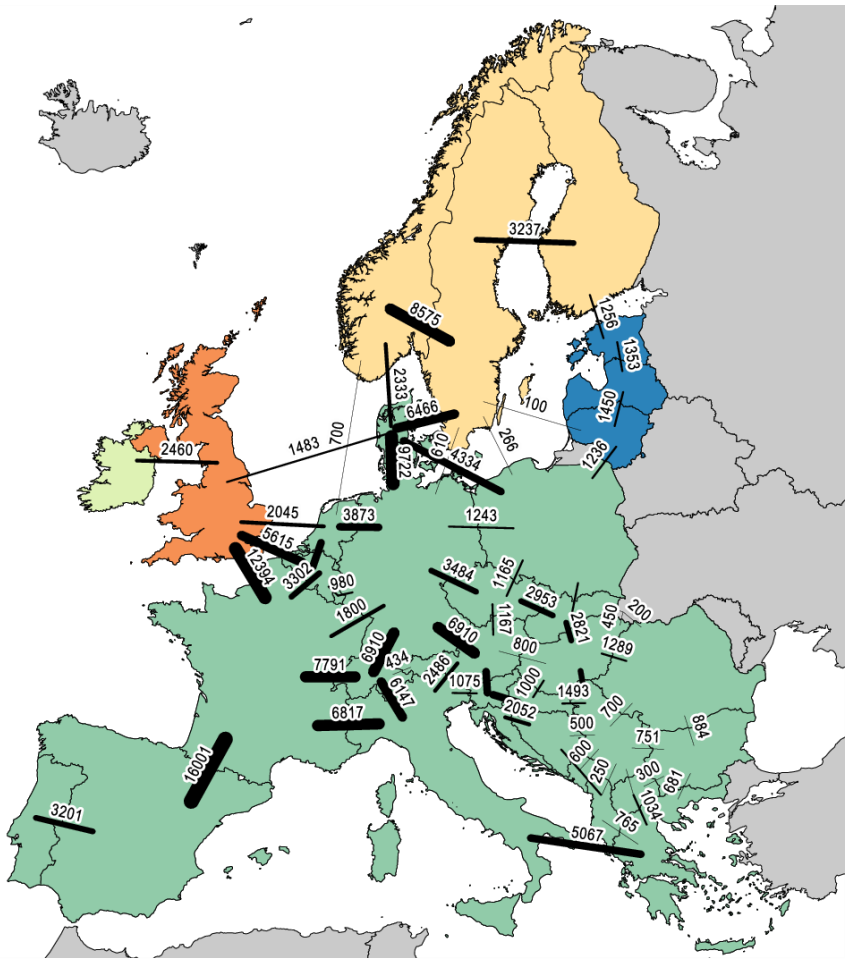


Figure 8.24.: NTC values in the year 2050 in MW, calculated with NTC approach

Figure 8.24 depicts the NTC values of the year 2050. Overall cross-border capacity expansion is similar to the flow-based approach. As expected, the cross border investments in continental are more evenly distributed in the flow-based approach, as all cross-border investments also influence the need for cross-border grid expansion on neighboring borders. This is not the case in the NTC approach. This can be seen at the Germany-France border, where no expansion takes place in the NTC approach and the transfer capacity through Switzerland is used, but in the flow-based approach the same line shows a capacity of 4,500 MW in 2050. The interconnector between Sweden and Lithuania is built in 2045, but only at a capacity of 100 MW.

The investment in electricity generation and storage capacities also changes slightly but not substantially by using the NTC approach. The largest shift between countries occurs also between Germany and France. Here Solar PV capacities and storage capacities of about 10 GW are shifted from Germany to France when the NTC approach is used. As the overall change is small, the shifts in installed capacity are

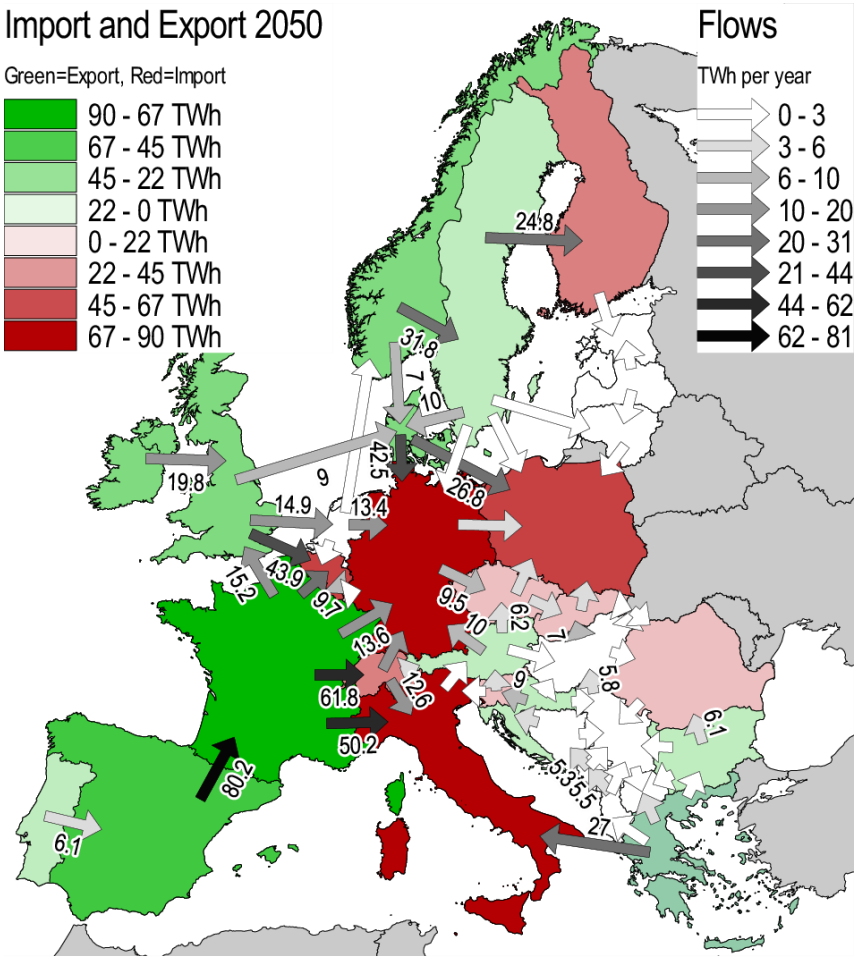


Figure 8.25.: Import and export in TWh in the year 2050, calculated with NTC approach

not depicted here. The imports and exports in 2050 resulting from the new NTC values are shown in Figure 8.25. The distribution of electricity transfers is also less evenly distributed when the NTC approach is in place, as implied by the methodology.

8.6.5. Discussion of limitations

dynELMOD can be used to answer a variety of questions about the future of the European electricity system. As it is a large scale model of the European electricity system, it has to abstract from many aspects which could influence the outcome.

One the one hand this is caused by the model formulation itself, which is a LP and thus neglects any non-linear relationships between parts of the system, on the other hand many other factors influence the results. The variability of the countries' regional characteristics is certainly greater than represented in dynELMOD. E.g. regionally different cost of capital might influence the results. In addition to the

points listed below, the model assumes no stochastic or other implementations of uncertainty regarding the development of relevant boundary conditions.

NTC and flow-based approach dynELMOD uses a country-sharp representation of the electricity system. This is due to practical reasons, but neglects the market design in certain parts of Europe, where one country contains multiple price zones, or price zones span multiple countries. Between the country zones, line expansion is approximated by increasing the NTC capacity. The cost for this kind of expansion is mainly dependent on the distance between the country centers (see Section 8.4.3). Therefore the true costs of increasing the interconnection capacity might be over- or underestimated. This is subject to further investigation in the future. Also separating price zones within countries is a possible extension of dynELMOD.

Time series In the previous sections the importance of temporal and spatial variation of the time series was highlighted, as the dynamics of the time series contribute largely to the model outcome. During the time series preparation step, the time series is smoothed. The smoothing of the reduced time-series leads to a loss of short-term variation between countries. This is expected, but overall temporal and seasonal characteristics are preserved adequately.

The goals of finding a cost-effective investment in future electricity system is not only driven by the GHG constraint, but also other aspects should be taken into account. Ensuring an adequate electricity system that provides sufficient generation or storage capacity while only using a small subset of all possible temporal variations during the investment determination step requires a robust time series reduction algorithm. Testing the outcome of the investment step is done in the dispatch step. This provides a good approximation, that the overall model outcome provides an adequate system, but includes only a single year of validation. Here, more extreme events that exceed the variation of the provided time series might not be represented adequately.

Sector coupling and other boundary conditions As discussed in Section 8.4.2, dynELMOD focuses on the development in the electricity sector. The interactions with other sectors is limited, and reflected by the demand development assumptions as well as flexibility approximations such as DSM. The future adoption of energy efficiency measures will also substantially affect the future demand of electricity, and not only change the total amount but also the daily and seasonal distribution of demand. Especially the interactions between the electricity and heat demands are currently subject to improvement, as CHP is not taken into account for new built power plants. Also a more detailed representation of the transportation sector and

corresponding BEV use is anticipated. As dynELMOD is also a partial equilibrium model, input assumptions such as the prices for coal and natural gas are fixed and do not vary when the electricity sector's demand changes.

Availability of generating units In dynELMOD a simple approximation of the availability of conventional power plants is implemented. Here average availability numbers over the course of the year are implemented.

Availability of CCTS and negative emissions The availability and possible cost to install CCTS as well as negative emissions to achieve a carbon-neutral electricity system is still unknown. We implement simple CCTS technology approximation, and allow biomass CCTS technology as a sensitivity.

Regional policies While dynELMOD can be used to determine the relationship of several influencing factors and boundary conditions, the effect of single policies that might drive the development is hard to measure, as the real-world implications of policy restrictions far exceed the complexity of such models. Especially as not only centrally administered policies are in place (such as the EU ETS) but also local policy development on a country level will shape the development of the future European energy supply. For example, the early adoption of renewable generation technologies in Germany is driven by the EEG, which in turn contributed to the current cost development of these technologies. The rate of transformation that can be undergone in single countries is not part of any constraint and might also be overestimated. Furthermore, by implementing constraints to reproduce policy measures, the correct functioning of the respective constraint is assumed.

8.7. Conclusion

This chapter describes the open-source model dynELMOD which determines the cost-minimal investment in and dispatch of generation and transmission infrastructure in the European electricity sector until 2050. The model combines several novel approaches to be able to approximate the underlying electricity grid infrastructure adequately, and to reduce the time frame of the investment calculation to keep the model size and computation requirement tractable. It provides a tool set to determine the effect of several boundary conditions that can be analyzed.

dynELMOD is applied to a dataset of the European electricity system, with assumptions on the future development of fuel prices, electrical demand, the development of future investment cost pathways. One of the major constraints is the

CO_2 emission constraint, which decreases almost linearly from 2020 to 2050 to reach almost complete decarbonization of the European electricity sector.

The model results show that no new nuclear, lignite, or hard coal capacities are built, but renewable energy sources provide the majority of the electricity generation in the future. Electricity production from nuclear, lignite and coal is phasing out gradually and not longer significant on a European scale after 2040. Until 2035 electricity production from gas is constant but from then on steep declining and will only be used as backup capacity in 2050. Due to the lower FLH of renewables energy sources compared to conventional energy sources this leads to an increase of installed capacity. Furthermore as renewable energy sources have a lower firm capacity, storage investments increase when high shares of renewable energy are reached. To balance out those possible fluctuations the interconnector capacity between countries will be increased. This allows to profit from the spatially different feed-in characteristics of renewable, especially wind. Furthermore fortified interconnections allows to transport electricity from locations with the highest wind speeds or solar radiation and therefore lowest production cost to the load centers of Europe. The results show mayor electricity flows from the south and the west towards central (east) Europe. This leads to changes compared to current import and export patterns, especially for Germany.

Discussion of model insights need to be done while being aware of the limitations that such a model contains. Therefore it is necessary to allow for full transparency and accessibility to the model formulation and the input data assumptions. In line with current trends, dynELMOD is published under an open source license, including the model formulation and all required input data.

Chapter 9

Scenarios for decarbonizing the European electricity sector

Previous versions were presented at the 10th Annual Trans-Atlantic Infraday (TAI 2016) in Washington, USA, and the 10. Internationale Energiewirtschaftstagung (IEWT 2017) in Vienna, Austria.

9.1. Introduction

Reducing the carbon emissions from the electricity sector is an essential element of any low-carbon energy transformation strategy, essentially because mitigating emissions in other sectors is more challenging and costly. Europe has set out particularly stringent targets for the low-carbon energy transformation: it has set a binding target of 40% greenhouse gas emission reductions until 2030 (basis: 1990), and a (non-binding) target of 80-95% reduction by 2050. Already the European Union (EU) "Reference Scenario," of 2011 the long-term energy projection carried out EU-wide every three years, did foresee an almost complete decarbonization of the electricity sector, with only 2% of the 1990 carbon dioxide (CO_2)-emissions remaining by 2050 (EC, 2011b). In doing so, it relies on a combination of fossil fuels, some of which is equipped with carbon capture, and some renewable energy sources. The chapter analyzes different scenarios of decarbonizing the electricity sector in Europe at the horizon 2050. In particular, we sketch out several scenarios of the transformation of the European electricity sector and discuss the implication of different assumptions on the foresight of the actors, such as perfect foresight, myopic foresight, and a budgetary approach (allocation of CO_2-emissions over the entire period from 2020 to 2050). We are also interested in the future role of nuclear power in the cost-minimal decarbonization pathway.

This chapter is structured in the following way: the next section describes the dynamic investment model of the European electricity market, called dynELMOD, which is a result of a decade of modeling work on electricity markets. Section 9.2 also describes the main data used in the model, including a survey of cost estimates for low-carbon technologies. Section 9.3 contains the definition of the scenarios, Section 9.4 the main results of the model calculations; in addition to the main scenarios we distinguish between a world with perfect foresight, one with myopic foresight, and one with an overall CO_2 budget available to the decision makers. Section 9.5 provides a discussion of the results, and Section 9.6 concludes.

9.2. Model and Data

9.2.1. dynELMOD: a detailed model of the European electricity sector

We apply the dynELMOD framework from Chapter 8, which is a dynamic investment and dispatch model for Europe formulated as a linear problem in GAMS. The objective is to minimize total system costs in Europe until 2050. To do so, the model can decide endogenously upon investments into conventional and renewable

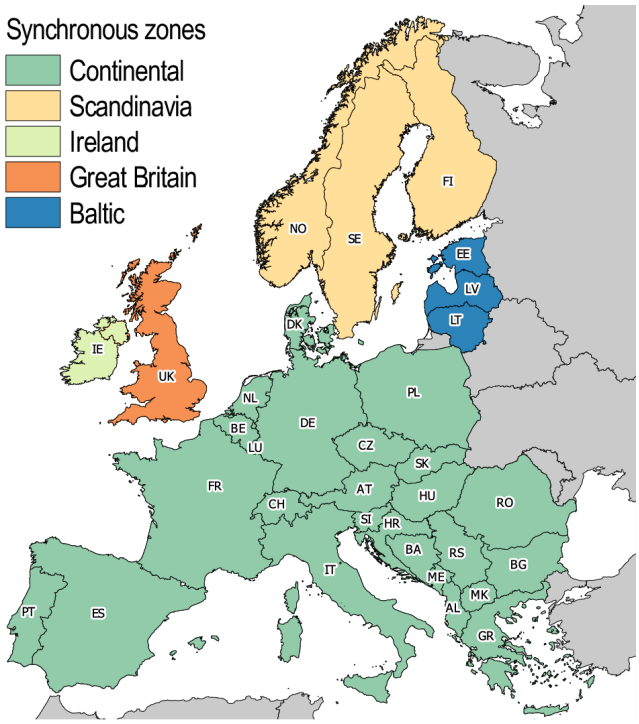


Figure 9.1.: dynELMOD geographical coverage

power plants, different storages including demand side management (DSM), and the high-voltage electricity transmission grid. This determines the solution space for the resulting power plant dispatch and electricity flows between countries. While for the investment decisions a reduced time frame is considered, the dispatch calculations are done in a subsequent step with a full year and checked for system adequacy. The time frame reduction technique allows to represent the general and seasonal characteristics of an entire year but also to achieve a continuous time series for renewables feed-in and electricity demand including times with low solar radiation and little wind in-feed. dynELMOD determines investments into electricity generation capacities in 5-years steps with a variable foresight length. The underlying electricity grid and cross-border interaction between countries is approximated using a flow-based market coupling approach based on a power transfer distribution factor (PTDF) matrix. It is derived from a full-fledged node- and line-sharp representation of the European high-voltage electricity system. Relevant boundary conditions are the CO_2-budget, decommissioning of existing plants after the ending of their lifetime and the electricity demand development. A detailed model description and the mathematical formulation can be found in Chapter 8.

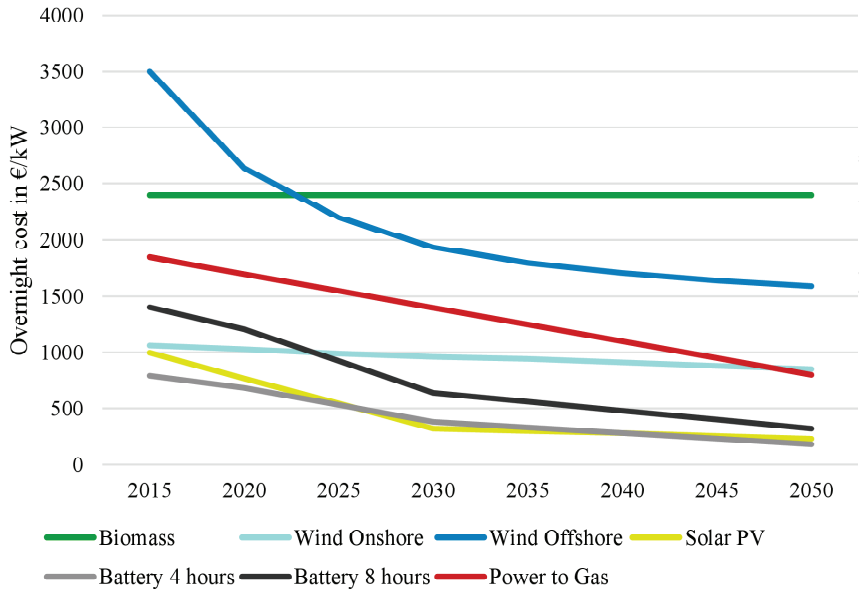


Figure 9.2.: Investment cost assumptions for selected technologies

9.2.2. Data

The data used describes the essential characteristics of the European electricity sector, including demand, electricity transmission, and generation and storage technologies. We use input data and assumptions provided in Chapter 8 that are published under an open source license. This dataset includes 33 countries, each represented with one node and located within five different synchronous areas (Figure 9.1). The anticipated development of the existing power plant portfolio serves as the baseline upon which investments into new generation capacity can be built. Potentials and different resource grades for renewable energy sources (RES) are included on a country resolution

An essential element of any dataset is the assumption about future investment costs. dynELMOD relies on an extensive survey of the literature carried out over the last years and documented in the DIW Berlin Data Documentation 68, published by Schröder et al. (2013a) and updated over time using newest studies and expert estimates. Figure 9.2 summarizes the main assumptions of how investments costs are likely to evolve.

Nuclear power invest costs have gone up systematically over the last decades, as observed by Grubler (2010), Joskow and Parsons (2012), and Rangel and Lévêque (2015). Consequently, the EU Reference Scenario 2016 has increased its estimates from 4,500 €/kW to 6,000 €/kW (EC, 2016).[86] We decided to take the average

[86] "Compared to the previous Reference Scenario costs of nuclear investments have been increased by over a third and the costs for nuclear refurbishments have also been revised upwards" (EC, 2016).

expected costs of the ongoing new build projects in Europe (Olkiluoto, Finland; Flamanville, France; and Hinkley Point, UK), and the US (Vogtle, Summers), and to discount them by 15% due to potential "first-of-a-kind" cost inflation.[87] Following the literature, we do not foresee economics of scale from potential "n^{th}-of-a-kind" plants, but we do not foresee any overnight cost increases neither. We add 900 €/kW in provisions for plant decommissioning and long-term storage, arriving at constant overnight costs of 6,000 €/kW – which is in line with the estimates of the European Commission (EC, 2016).

Cost estimates for renewables rely on a large number of figures provided by industry and independent experts. We expect the cost degression of solar photovoltaic (PV) to continue, though at a slower pace over time; onshore wind also has a positive, but significantly less steep learning curve. The estimates for offshore wind are subject to a much higher uncertainty. Biomass is expected to remain by far the most expensive renewable source.

Cost development estimates for storage and DSM technologies are based on Pape et al. (2014) and Zerrahn and Schill (2015a). For assumptions about costs for carbon capture, transport and storage (CCTS) technologies, which can be implemented as a sensitivity but are not included in the default model runs, we follow the optimistic forecast by the industry to propose a technology that is not yet available at commercial scale (Oei and Mendelevitch, 2016; Schröder et al., 2013a).

9.3. Scenarios

We apply dynELMOD to three main scenarios with different degrees of planning foresight regarding the decarbonization pathway until 2050. Our objective is to analyze the development of the European electricity sector under different boundary conditions. dynELMOD can present different scenarios of how decision makers deal with information: The knowledge (or lack thereof) how the electricity sector's future boundary conditions will evolve can have a substantial impact on the investment decisions done over time. Therefore we test different assumptions regarding the planner's foresight:

- The *Default Scenario* anticipates an overall moderate electricity demand increase as well as an almost complete decarbonization of the electricity sector in Europe until 2050. It serves as a reference for the next scenarios. It assumes perfect foresight over the entire horizon (2015–2050). The central decision maker faces a yearly CO_2 constraint, which reduces carbon dioxide emissions by 2050 to only 2% of the current level.

[87] See the detailed methodological approaches set out by D'haeseleer (2013) and Rothwell (2015).

- By contrast, a *Reduced Foresight* scenario considers that the decisions makers are only aware of the CO_2 target of the upcoming five-year period, and thus behave "myopically." The interest of this scenario is to model possible short-sightedness of politicians due to election cycles as well as investors' limited trust in long-germ (environmental and) political targets. The results should therefore identify the danger of stranded investments resulting from such a short-term vision.
- An alternative scenario to reflect a different CO_2 allocation mechanism is implemented in the *Budget Approach*: decision makers receive an aggregate emission budget covering the entire period from 2015 up to 2050 ($\approx$ 22.5 bn. t of CO_2), and then can use this budget at their discretion over the period. An additional constraint is that the annual emissions in 2050 are not allowed to exceed 2% of 2015 CO_2 emission levels. The budget approach has become popular among climate policymakers and academic researchers recently. It allows decision makers a higher degree of decision resulting in lower overall costs. In general, abatement decisions are taken earlier to "save" emission rights for the final years where abatement is expected to become more expensive.

9.4. Results

9.4.1. European electricity under emission constraints

The model results give insights into a possibility for the generation capacity development in the European electricity sector until 2050. Figure 9.3 shows the development of electricity generation in Europe between 2020 and 2050, in five-year steps, under the given linear CO_2-reduction path to 2% in 2050. Due to high investment costs, no new nuclear power plants are built, and therefore nuclear power generation is reduced over time as older plants reach the end of their technical lifetime. Renewables become the dominant electricity source in Europe. In the absence of carbon capture technology due to high costs, lignite and coal are phased out as no new coal capacities emerge. Gas electrification, on the other hand, is expanded until 2035. Although 215 GW of gas-fired capacities are built, their usage declines significantly after 2035, to become a backup technology. Electricity generation from biomass and other sources such as waste and geothermal energy remains nearly constant.

The largest share of the abatement is carried by renewable sources, wind (onshore and offshore) and solar PV. In the competition between the renewables, wind dominates, obtaining a share of over 60% in 2050. This share consists of onshore wind generating 1,570 TWh, and offshore wind adding additional 951 TWh. Despite benefiting from the strongest cost degression, solar PV produces "only" 1,070 TWh

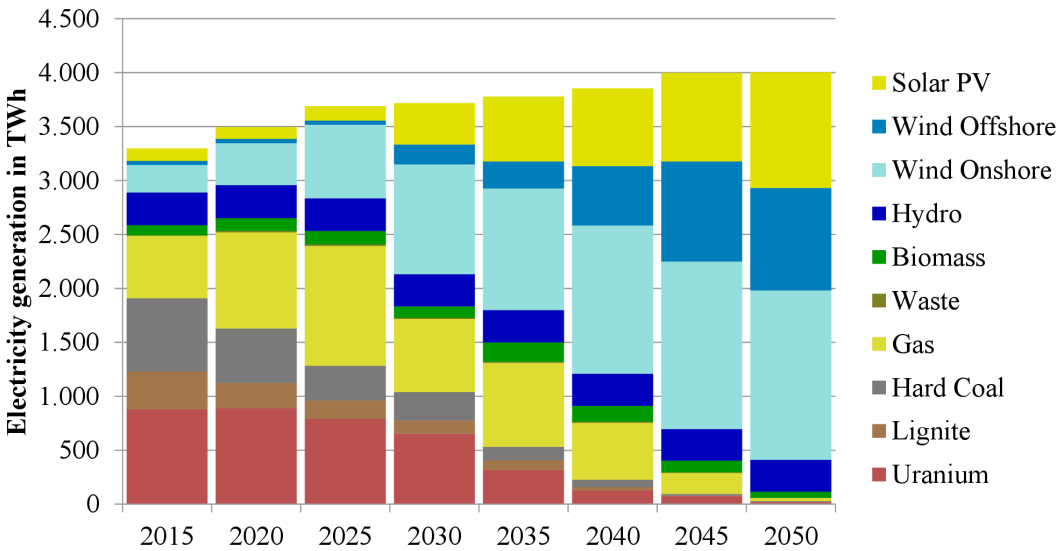


Figure 9.3.: European electricity generation in the *Default Scenario* 2015–2050

in 2050; even though not less than 880 GW of solar PV capacities are installed in 2050. The installations of wind are lower with capacities of 740 GW Onshore and 270 GW Offshore.

To accommodate the fluctuation of renewables, a total of 465 GW of storage capacities are built, mainly towards the latter half of the period. New pumped storage capacities are negligible due to limited new potential. Therefore lithium-ion battery storage obtains almost all investments. DSM, although implemented in the model, only plays a marginal role, providing only 3% of the flexibility needed in the system.

Figure 9.4 shows the accumulated investments in power generation capacities in the default scenario in France, Spain, the United Kingdom (UK), Germany, Italy, Poland, Greece, and the Netherlands from 2020 until 2050. Aging conventional power plant fleets especially in France, Spain and the UK call for a refurbishment of the electricity system. Investments in France are highest overall, with 47 GW of new gas power plants, 147 GW onshore and 75 GW offshore wind installations. Investments in solar PV are also above 100 GW, investments in concentrated solar power (CSP) plants appear only in minor quantities and are aggregated under the solar PV category. In Spain, no new investments in conventional power plants are observed, but onshore wind and solar PV dominate the future electricity generation. This leads to investments into storage technologies of 92 GW. In Germany, onshore and offshore wind power obtain the largest share of investments with 74 GW and 65 GW respectively, whereas the model builds 100 GW of solar PV. Italy shows a different profile, where almost only solar PV capacities are built until 2040, followed

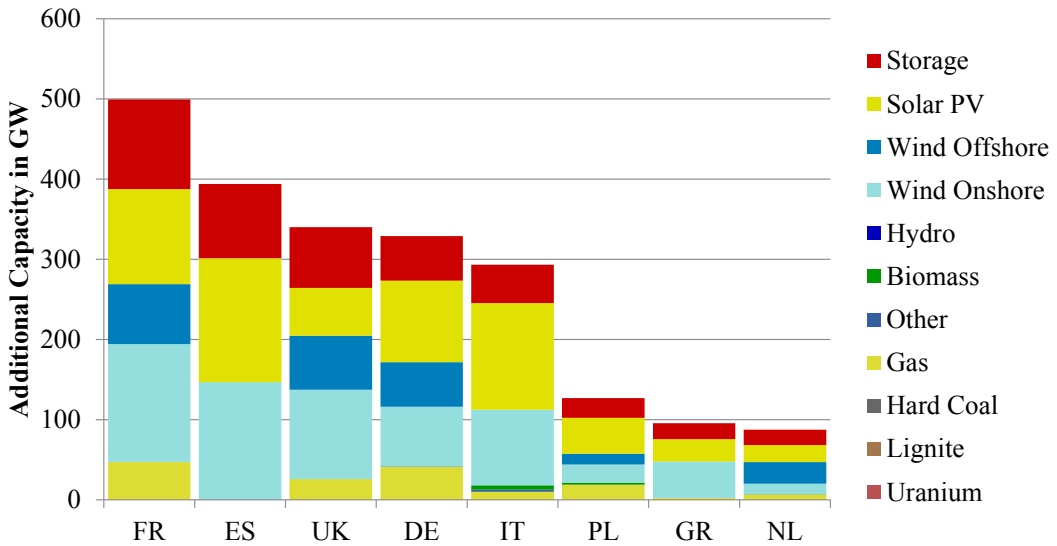


Figure 9.4.: Accumulated investments in generation capacities in the *Default Scenario* in selected countries from 2020-2050

by some wind, and a little bit of biomass investments. In both countries, the need for storage increases over time.

9.4.2. Reduced foresight leads to stranded investments

We now compare differences that emerge from different assumptions about the foresight of the decision makers. In the scenario *Reduced Foresight* the myopic foresight, e.g. a reduced vision of future CO_2 abatement needs, leads to a different investment strategy as the future decarbonization targets are not taken into account. This provides insights into possible developments of the power plant portfolio in case the overall investment decision making is not driven by a belief in further decarbonization in the future. This leads to significantly higher investments in carbon fuel capacities. Figure 9.5 shows the differences in investments between the *Reduced Foresight* scenario, compared to the *Default Scenario*. Clearly, large quantities of "stranded" investments into gas fired capacities would occur, e.g. in the UK 15 GW, France 14 GW, Spain 7 GW, and Germany 6 GW. In the years 2020 and 2025, the investments in gas capacities are similar to the default scenario. But in 2030 and 2035 additional 56 GW and 59 GW are added to the system, which is 22 GW respective 53 GW higher than in the default scenario. Afterwards no investments take place. No investments into coal-fired power plants occur even in the *Reduced Foresight* scenario.

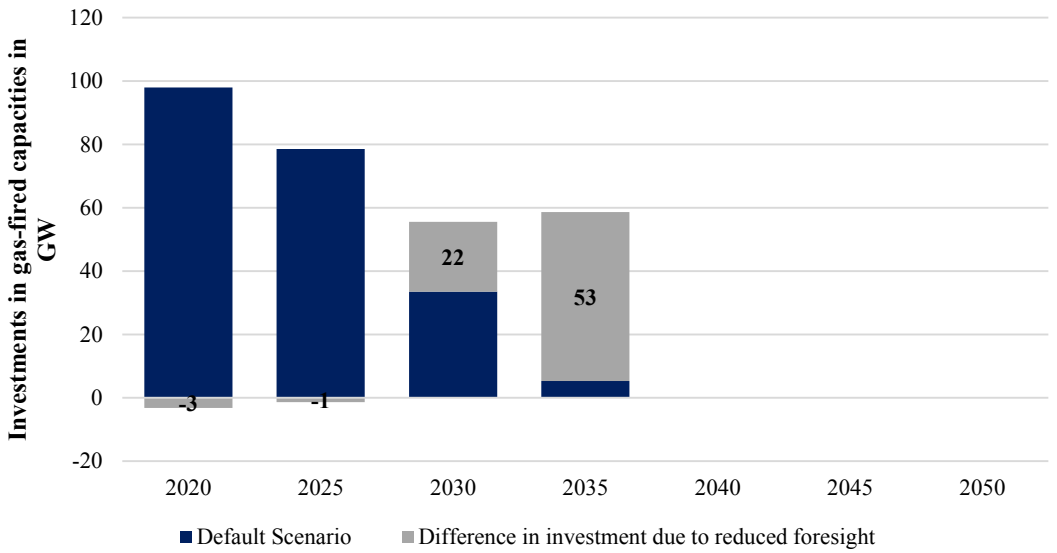


Figure 9.5.: Investment differences for gas power plants in *Reduced Foresight* scenario vs. *Default Scenario* from 2020 – 2050 in Europe

9.4.3. Emissions comparison

In Figure 9.6 the CO_2-emissions over time by fuel are depicted for the default and the reduced foresight scenarios, as well as the difference in emissions induced by the reduced model foresight. In the default setting, emissions from hard coal and lignite decrease faster than emissions from gas, where until 2025 an increase in emissions follows. From 2035 onward, emissions from coal are overtaken by gas, which is from then onwards the largest source of CO_2-emissions. In 2050, the remaining 19 Mt of CO_2 almost exclusively originate from gas.

In the case of reduced model foresight, the timing and structure of investments is different. In the *Reduced Foresight* scenario, investments in gas capacities are similar initially, but starting in 2030, are significantly higher than in the default scenario. At this point, the investment structure of the *Default Scenario* has shifted to a mostly storage and renewables-based one, whereas investments into gas capacities remain stable until 2035 in the *Reduced Foresight* scenario. These capacities of additional 22 GW in 2030 and 53 GW in 2035 lead to additional stranded fossil capacities as the emission constraint remains the same. Especially run times of carbon-intensive coal power plants are substituted by these additional gas power units. The average full load hours of coal-fired power plants are decreased by more than 1.000 hours in between 2030 and 2040, the decrease of lignite's full load hours is accelerated compared to the default scenario, where full load hours above 6,000 are observed until 2035. The additional gas capacities decrease the full load hours to less than 4,000 in 2035.

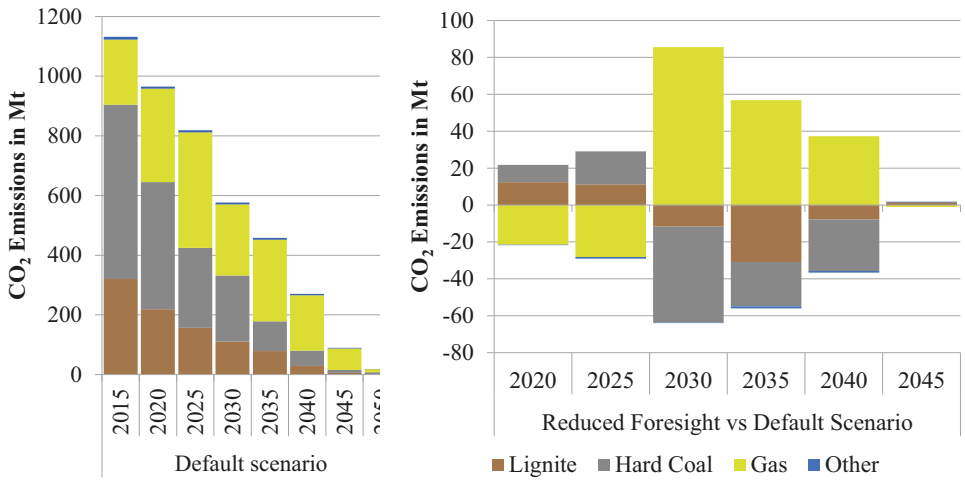


Figure 9.6.: CO_2 emissions by fuel and scenario

9.4.4. Emissions in the Emission Budget scenario

We now compare the results of the *Default Scenario* with those of the *Emission Budget* scenario, where the decision maker is free to allocate the total emission budget (here: about 22.5 bn. t CO_2) over the entire period. Figure 9.7 shows the difference between the CO_2 emissions in the default scenario with those occurring under an emission budget. Clearly, the control of the full budget leads to a reduction of emissions in the early period (2020 – 2030), where emissions are about 170 Mt lower than in the default scenario. On the contrary, in 2040 and 2045, emissions under the budget approach increase beyond the default scenario: they are highest in 2045. Overall system costs over the entire period can be reduced by about 1% due to this shift which amounts to about 1.2 bn € per year for the entire model region. One interpretation of this result is that the new degrees of freedom invite the decision maker to use "low hanging fruits" of abatement earlier, mainly by reducing existing overcapacities of coal and lignite electrification. This strategy allows for additional emissions, primarily used by gas plants, towards the end of the modeled period.

9.5. Discussion

9.5.1. Operating a low-carbon electricity system in 2050

Can a largely renewables-based electricity system, that dynELMOD foresees as the lowest-cost solution for decarbonization, deliver secure electricity? Previously, it was considered that intermittent renewables needed to be balanced by conventional capacities, mainly gas. With the cost degression of both renewable energy and storage capacities, and under a strict carbon constraint, the renewables-gas combination is

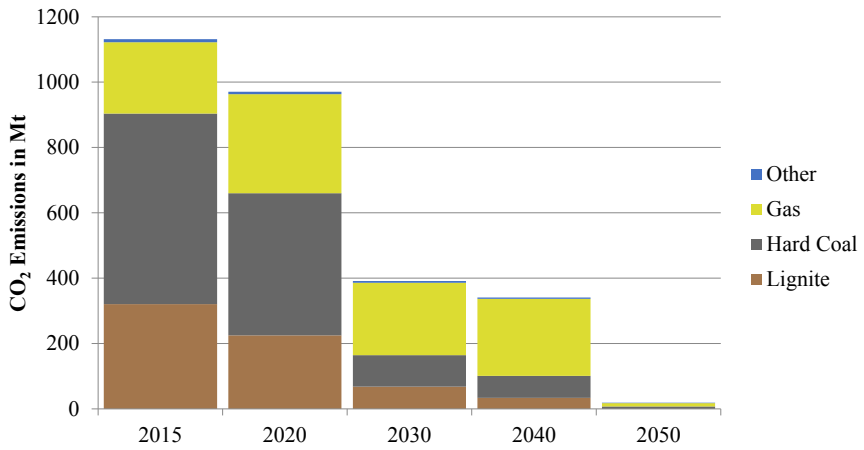


Figure 9.7.: CO_2 emissions in the "Emission Budget" scenario (2020 – 2050) in ten-year steps

much less attractive. This section looks at the concrete hour-to-hour functioning of the electricity system and specifically addresses the operation in different European countries using Germany and Italy as examples. Aside from pure electricity generation aspects, also stability of the system and the use of ancillary services with rising shares of renewables becomes important. Lorenz (2017) estimates that balancing services can be provided in decarbonized electricity systems at current cost levels if technical and regulatory boundary conditions enable participation of renewables.

Figure 9.8 shows the hour-to-hour functioning of the German electricity system in the default scenario. The two depicted weeks in early February 2050 are the most critical period in the year regarding demand peaks as well as low solar PV availability and intermittent periods of low wind in-feed as well. Given the investment program sketched out above, wind is clearly the dominant source of supply and delivers 47% of total electricity in that two-week period. Both wind and solar PV are intermittent and have moments where little of it is available, such as around the model-hour 953, that – in addition to electricity trade, i.e. imports – significant amounts of storage are necessary. Points at which the system is in an inadequate configuration do not occur in any model hour. These storages are charged at times of high renewable availability or low demand. Between 2020 and 2050, 56 GW of storage capacity have been built. Figure 9.8 also shows how the combination of storage and trade assures a secure supply of electricity even in the most critical hours of the year. The imports come in decreasing order from Denmark, Switzerland, the Netherlands, France, and Austria. The balance with Sweden and Poland is roughly zero. At the same time on average 960 MWh are exported to the Czech Republic. As dynELMOD is a model with an hourly resolution, ramping constraints can only apply to a subset of technologies such as lignite power plants. Gas capacities can ramp to their full capacity within a

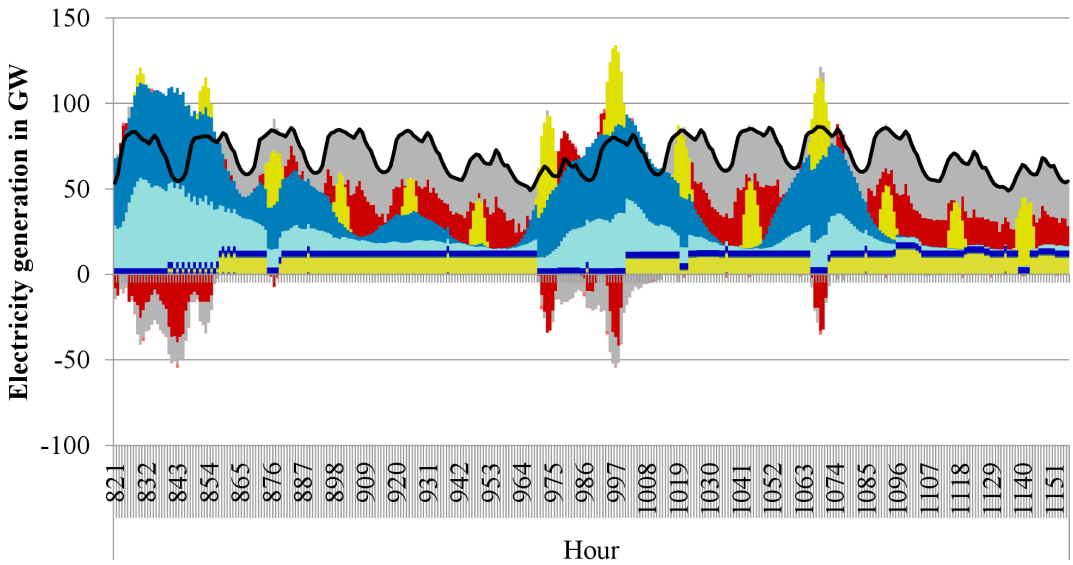


Figure 9.8.: Hour-to-hour operation of the German electricity system in 2050 (first two weeks of February) for the default scenario

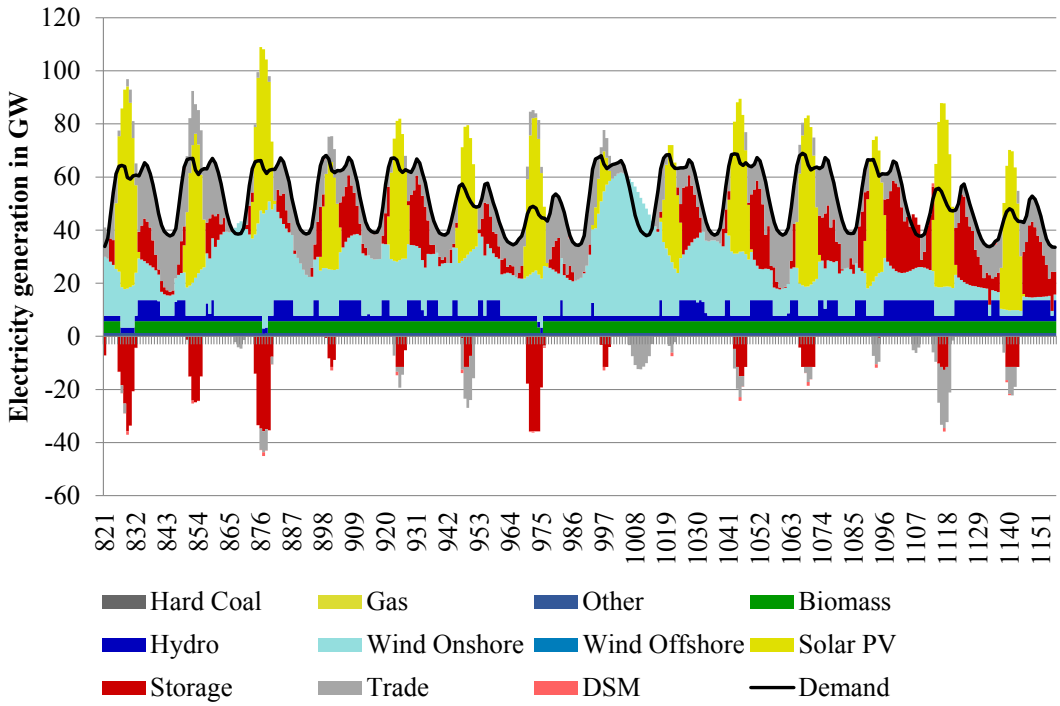


Figure 9.9.: Hour-to-hour operation of the Italian electricity system in 2050 (first two weeks of February) for the default scenario

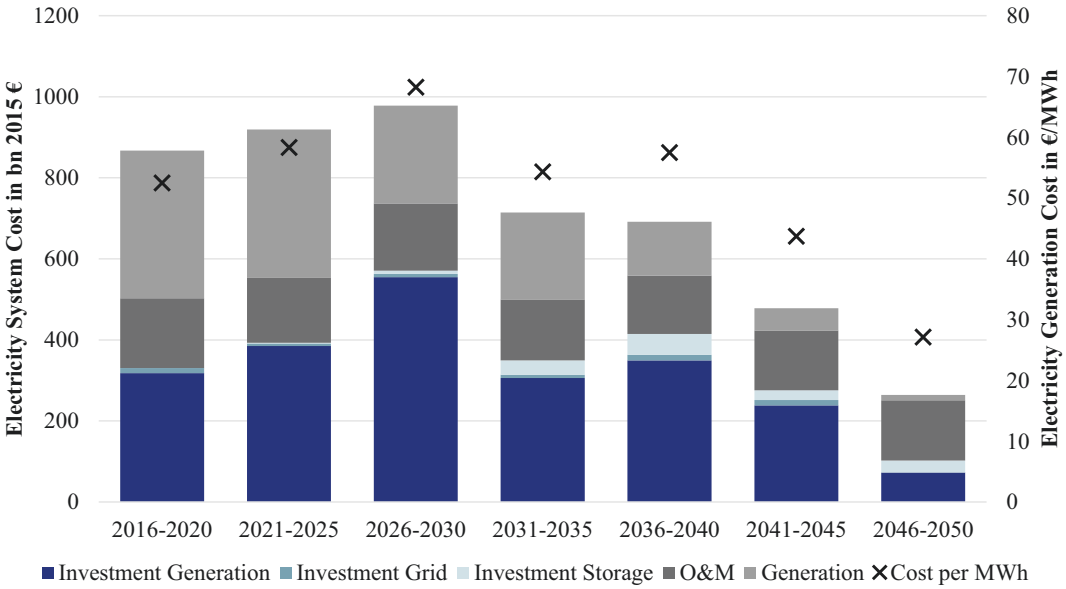


Figure 9.10.: Overall electricity system costs (2020 – 2050), by segment

single hour. This is visible in Figure 9.8, where gas capacities show high ramping rates. As the electricity system is almost fully decarbonized in 2050, the electricity supply of gas capacities is limited throughout the year.

Figure 9.9 presents a similar exercise for Italy, also in the time-frame of the first two weeks of February for the default scenario. The dispatch of generation technologies in Italy is shaped by wind in-feed as well as solar PV availability which during the day often exceeds the demand. During these hours, storage capacities are charged to release the power during the evening hours. Italy also intermittently relies on imports mainly from France, Switzerland, and Greece.

9.5.2. Costs and prices to 2050

The rapid sector transformation leads to substantial investments into a different power generation and storage portfolio compared to today's outset. The costs associated with this transformation and the resulting average electricity generation costs are discussed in this section. Figure 9.10 shows the composition of total system costs for the default scenario, about €$_{2015}$ 4,900 bn., composed of initially approximately equal shares for variable costs, investment costs, and operation & maintenance costs. Over time variable generation costs decrease as the system shifts to a more renewables based dispatch. Even though it constitutes a crucial element in the generation mix, the costs for storage make up only about 3% of total system costs. Also, investments in the electricity grid infrastructure only contribute to 1.3% of the total costs.

Dividing the system costs by electricity generation provides an aggregate average cost of supplying Europe with electricity. Figure 9.10 also shows the development of average costs for the period 2020 – 2050, which shows a decreasing trend: from 52 €/MWh in 2020, mainly based on fossil fuels, until 2050, where an average cost of 27 €/MWh is reached.

Last but still not least we take a look at the implicit CO_2-prices that the model renders as the shadow price on the carbon constraint. Not surprisingly, the reduction of the available CO_2 emissions in the *Default Scenario* leads to an increase in the implicit CO_2 price (which is not explicitly paid by the emitting firm): from 32 €/t (2020) to 177 €/t (2050). The price development of the *Reduced Foresight* is comparable to the default scenario, here the price increase occurs at a later stage between 2045 and 2050. For the emission budget, no yearly values, but a price spanning the entire model period is available. At about 34 €/t it reflects the shadow price of an additional ton of CO_2 at any point during the period from 2015 to 2050.

9.6. Conclusion

Enabling a decarbonization of the electricity sector is crucial for keeping global temperature rise under 2 °C, as mitigating emissions in other sectors is more difficult and costly. No investment in new hard coal or lignite fueled power plants are observed in any scenario. Incorporating the climate targets makes the investment into any additional conventional capacity uneconomic from 2025 onwards, resulting in a coal and gas phase-out in the 2040s.

However, international consensus on how to achieve a decarbonization of the sector is lacking. Electricity generation will undergo substantial structural change over the next three decades, and developments in Europe, where strict carbon restrictions are likely to be imposed, are a particularly interesting case. This chapter presents different scenarios for the decarbonization of the European electricity sector in 2050 relying on a very detailed model of electricity generation, transmission, and consumption, called dynELMOD.

The model is run using different foresight assumptions. These results quantify the advantage of a structured energy transition pathway instead of potentially short-sighted decisions. Limited foresight results in stranded investments of fossil 75 GW gas-capacities in the 2030s. The amount of stranded investments is small compared to the overall installed capacities, but a robust result across sensitivities. Using a CO_2 budgetary approach, on the other hand, leads to an even sharper emission reduction in the early periods before 2030, reducing overall overall costs by 1%. A more rapid decarbonization of the European electricity system due to the COP21

Paris agreement does also not lead to an adoption of nuclear power plant but relies on further expansion of renewables and storage capacities.

We find that in the default scenario, renewables carry the major burden of decarbonization, other technologies such as nuclear power (3rd or 4th generation) and carbon capture appear to be unable to compete.

Transforming the electricity system towards 98% decarbonization changes the overall generation structure substantially. The accompanying total electricity generation cost shows a downward trend after reaching its highest point in 2025, to arrive at a minimum of 27€/MWh in 2050 in the default scenario. Across all scenarios costs in 2050 range between 27€/MW and 32€/MW and therefore below levels of 2017.

Further research should address the diffusion process of new technologies, mainly renewables and storage: we have assumed the emerging technologies to be available globally, and at identical, rather low costs. However, these assumption may not be provided in practice. Another important aspect is the future use of nuclear energy. While electricity from nuclear energy is clearly not economic, some countries are likely to pursue the nuclear route, for other reasons, and this should be reflected in the specific scenario runs. Last but not least, the role of electricity transmission infrastructure needs to be critically reviewed: in our scenarios, transmission constraints seem to play a minor role, whereas this might look quite different in the real world.

Appendix A

Appendix to Chapter 2 and 3

A.1. Nomenclature

The following tables give an overview of all sets, parameters, and variables used in ELMOD-MIP.

Table A.1.: Sets in ELMOD-MIP

Sets	
t, tt	Time
r	Region
p	Power plants
c	Subset of conventional power plants
u	Subset of fast starting power plants
o	Subset of must-run power plants
s	Subset of PSP powerplants
bl	Blocks of balancing power
b	Balancing power product

Table A.2.: Parameters in ELMOD-MIP

Parameters	
c_p^{start}	Cost per start-up
c_p^{down}	Cost per shut-down
mc_c	Marginal generation costs
g_p^{max}	Maximum generation
g_p^{min}	Minimum generation if online
g_t^{sol}	Solar energy feed-in
g_t^{wind}	Wind energy feed-in
g_t^{bio}	Biomass energy feed-in
r_p^{down}	Maximum ramping down speed [% per hour]
r_p^{up}	Maximum ramping up speed [% per hour]
q_t^{spot}	Electricity load
$q_{b,bl,r,t}^{resv,neg}$	Total amount of negative balancing power needed
$q_{b,bl,r,t}^{resv,pos}$	Total amount of positive balancing power
$q_{b,r,t}^{call,neg}$	Total Negative activation in per region, time, and product
$q_{b,r,t}^{call,pos}$	Total Positive activation in per region, time, and product
$f_{r,rr}^{max}$	Max flow
$frq_{bl,b}$	Activation frequency of balancing reserve in a specific block
l_s^{max}	Maximum storage level
l_s^{min}	Minimum storage level
v_s^{max}	Maximum storage release
w_s^{max}	Maximum storage loading
η_s	Storage efficiency
$g_{s,t}^{nat}$	Natural inflow into storage

Table A.3.: Binary Variables in ELMOD-MIP

Binary Variables	
$ON_{c,t}$	Plant status
$UP_{c,t}$	Plant startup variable
$DN_{c,t}$	Plant shutdown variable
$SB_{b,bl,u,t}$	Activation from standby per product and block for fast starting plants

Table A.4.: Variables in ELMOD-MIP

Variables	
$Cost$	Objective value: total cost
$Cost^{gen}$	Generation cost
$Cost^{resv}$	Total balancing reservation cost
$Cost^{call}$	Total balancing activation cost
$Cost^{start}$	Total start up cost
$Cost^{down}$	Total shut down cost
$G_{c,t}$	Conventional generation in MW
$G^{resv,pos}_{p,t,bl,b}$	Positive reserved balancing power assigned to a plant
$G^{resv,neg}_{p,t,bl,b}$	Negative reserved balancing power assigned to a plant
$G^{resv,pos,A}_{s,t,bl,b}$	Positive reserved balancing power of a PSP (active = more generation)
$G^{resv,pos,P}_{s,t,bl,b}$	Positive reserved balancing power of a PSP (passive = less pumping)
$G^{resv,neg,A}_{s,t,bl,b}$	Negative reserved balancing power of a PSP (active = more pumping)
$G^{resv,neg,P}_{s,t,bl,b}$	Negative reserved balancing power of a PSP (passive = less generation)
$G^{call,pos}_{b,p,t}$	Positive activated balancing energy
$G^{call,neg}_{b,p,t}$	Negative activated balancing energy
$F^{spot}_{r,rr,t}$	Spot market flow
$F^{resv,pos}_{b,bl,r,rr,t}$	Reservation of positive balancing flow
$F^{resv,neg}_{b,bl,r,rr,t}$	Reservation of negative balancing flow
$F^{call,pos}_{b,r,rr,t}$	Positive balancing flow
$F^{call,neg}_{b,r,rr,t}$	Negative balancing flow
$F^{resv,pos,ge0}_{b,bl,r,rr,t}$	Positive part of the reservation of positive balancing flow
$F^{resv,pos,le0}_{b,bl,r,rr,t}$	Negative part of the reservation of positive balancing flow
$F^{resv,neg,ge0}_{b,bl,r,rr,t}$	Positive part of the reservation of negative balancing flow
$F^{resv,neg,le0}_{b,bl,r,rr,t}$	Negative part of the reservation of negative balancing flow
$Frq^{max}_{u,t}$	Highest possible Activation Frequency in specific hour
$PSP^{discard}_{s,t}$	Discard of excess water
$PSP^{D}_{s,t}$	Storage loading (pumping)
$PSP^{G}_{s,t}$	Storage release (generation)
$PSP^{L}_{s,t}$	Storage level

Appendix B

Appendix to Chapter 4: Power system impacts of electric vehicles in Germany

B.1. The model

Table B.1 lists all sets, parameters, and variables related to electric vehicles. The complementary Table B.2 includes all other sets, parameters, and variables of the basic dispatch model. EV-related equations have already been described in Section 4.2. In the following, we provide the analytical formulation of the remainder of the model.

Table B.1.: Sets, parameters, and variables related to electric vehicles.

Sets	**Description**	**Unit**
$ev \in EV$	Set of 28 EV profiles	
Parameters		
$batcap_{ev}$	EV Battery Capacity	kWh
$chargemax_{ev,t}$	Hourly power rating of the charge connection (0 when car is in use or parked without grid connection)	kW
$cons_{ev,t}$	Hourly EV power consumption	kWh
η_{ev}	EV charging efficiency	%
$fastchargegoal$	Restricts the relative battery charge level that should be reached as fast as possible (1 for fully user-driven charging, 0 for cost-driven)	
$penalty^{Phevfuel}$	Penalty for non-electric PHEV operation mode	€/MWh
$phev_{ev}$	Defines whether an EV is a PHEV/REEV (1 if yes, 0 otherwise)	
n_{ev}	Quantity of EVs per load profile	
Binary variables		
$FULLCHARGE_{ev,t}$	1 if full charging power is required, i.e., when the charge level is below $fastchargegoal$, and 0 otherwise	
Continuous variables		
$Charge_{ev,t}$	Cumulative EV charging power	MW
$Chargelev_{ev,t}$	Cumulative EV battery charge level	MWh
$Phevfuel_{ev,t}$	Cumulative PHEV conventional fuel use	MWh

$$
\begin{aligned}
Cost = &\sum_{i,t} (vc_i Q_{i,t} + sc_i ST_{i,t}) \\
&+ \sum_{j,t} vstc_j Stout_{j,t} \\
&+ \sum_{t} penalty^{Peak} Peak_t \\
&+ \sum_{ev,t} penalty^{Phevfuel} Phevfuel_{ev,t}
\end{aligned} \tag{B.1}
$$

$$Q_{i,t} \leq qmax_i avail_{i,t} U_{i,t} \qquad \forall i, t \tag{B.2}$$

$$Q_{i,t} \geq qmin_i avail_{i,t} U_{i,t} \qquad \forall i, t \tag{B.3}$$

Table B.2.: Sets, parameters, and variables of the basic model.

Sets	**Description**	Unit
$i \in I$	Set of thermal power plant blocks of various technologies	
$i \in J$	Set of thermal storage technologies	
$res \in RES$	Set of fluctuating renewable technologies	
$t, tt \in T$	Time set	hours
Parameters		
$avail_{i,t}$	Availability of thermal blocks	%
$availbio_t$	Availability of biomass generation	%
dem_t	Hourly power demand (without EV consumption)	MWh
$energymaxbio$	Yearly biomass power generation budget	MWh
$othergen_t$	Exogenous other hourly power generation (hydro, waste)	MWh
$penalty^{Peak}$	Penalty for use of backstop peak technology	€/MWh
$qmax_i$	Hourly Generation capacity of thermal blocks	MWh
$qmaxbio$	Hourly biomass generation capacity	MWh
$qmin_i$	Minimum hourly generation of thermal blocks	MWh
$resavail_{res,t}$	Hourly availability of fluctuating renewables	MWh
sc_i	Start-up costs of thermal blocks	€
$stinmax_j$	Hourly storage loading capacity	MWh
$stime_i$	Start-up time of thermal blocks	Hours
$stlevmax_j$	Maximum storage level	MWh
$stoutmax_j$	Hourly storage discharging capacity	MWh
vc_i	Variable generation costs of thermal blocks	€/MWh
$vstc_j$	Variable generation costs of storage technologies	€/MWh
Binary variables		
$ST_{i,t}$	Start-up variable of thermal blocks (1 if block is started up in period t, 0 otherwise)	
$U_{i,t}$	Status variable of thermal blocks (1 if block is generating, 0 otherwise)	
Continuous variables		
Bio_t	Generation from biomass	MWh
$Cost$	Total dispatch costs	€
$Rescurt_{res,t}$	Hourly curtailment of fluctuating renewables	MWh
$Resint_{res,t}$	Hourly system integration of fluctuating renewables	MWh
$Peak_t$	Hourly generation of backstop peak technology	MWh
$Q_{i,t}$	Quantity of power generated by thermal block i in hour t	MWh
$Stin_{j,t}$	Hourly power fed into storage	MWh
$Stlev_{j,t}$	Hourly storage level	MWh
$Stout_{j,t}$	Hourly power generation from storage	MWh

$$ST_{i,t} \geq U_{i,t} - U_{i,t-1} \qquad \forall i, t \tag{B.4}$$

$$0 \leq 1 - U_{i,tt} - U_{i,t-1} + U_{i,t} \qquad \begin{array}{l} \forall i, t, tt \\ t \leq tt \leq t + stime_i \end{array} \tag{B.5}$$

$$resavail_{res,t} = Resint_{res,t} + Rescurt_{res,t} \qquad \forall res, t \tag{B.6}$$

$$Rescurt_{res,t} \leq resavail_{res,t} \qquad \forall res, t \tag{B.7}$$

$$Bio_t \leq availbio_t qmaxbio \qquad \forall t \qquad \text{(B.8)}$$

$$\sum_t Bio_t \leq energymaxbio \qquad \text{(B.9)}$$

$$Stlev_{j,t} = Stlev_{j,t-1} + Stin_{j,t}\eta_j - Stout_{j,t} \qquad \forall j,t \qquad \text{(B.10)}$$

$$Stlev_{j,t} \leq stlevmax_j \qquad \forall j,t \qquad \text{(B.11)}$$

$$Stin_{j,t} \leq stinmax_j \qquad \forall j,t \qquad \text{(B.12)}$$

$$Stout_{j,t} \leq stoutmax_j \qquad \forall j,t \qquad \text{(B.13)}$$

$$\begin{aligned} dem_t = & \sum_i Q_{i,t} - \sum_{ev} Charge_{ev,t} \\ & + \sum_{res} Resint_{res,t} + Bio_t \\ & + Peak_t + othergen_t \\ & + \sum_j (Stout_{j,t} - Stin_{j,t}) \end{aligned} \qquad \forall t \qquad \text{(B.14)}$$

The objective function (B.1) sums up variable generation costs of thermal plants, including start-up costs of single blocks, variable storage costs as well as penalties for using the backstop peak load technology and for non-electric operation of PHEV/REEV. Eqs. (B.2) and (B.3) establish maximum and minimum generation levels for thermal blocks. Note that the binary status variable $U_{i,t}$ is 1 if the plant is online and 0 otherwise. Eq. (B.4) ensures consistency between the binary status and start-up variables of thermal generators. Eq. (B.5) enforces a start-up time restriction. Eqs. (B.6) and (B.7) determine hourly system integration as well as curtailment of fluctuating renewables such as onshore and offshore wind power and solar PV. Eq. (B.8) is an hourly power generation capacity restriction for biomass, whereas (B.9) constrains overall biomass utilization, for example, because of resource constraints. Eq. (B.10) connects storage levels of subsequent periods, given inflows and outflows. Here, round- trip efficiency losses are attributed to storage loading. Eqs. (B.11–B.13) establish upper limits on the storage level, the loading capacity as well as the discharging capacity. Finally, the market clearing condition (B.14) ensures that overall supply equals demand in all hours.

Thermal power plants are modeled as single blocks in a unit commitment formulation with respective start-up costs and start-up times; in contrast, other generation technologies such as storage, biomass and variable renewables are modeled in a linear way as aggregated capacities which are assumed to be perfectly flexible. Only in the 2010 scenario, we assume generation from biomass to be completely inflexible, i.e., fixed to average levels. In addition, we include inflexible power generation from run-of river hydro and waste incineration as an exogenous parameter $othergen_t$, drawing on historic data.

B.2. Dispatch outcomes without EVs

Figure B.1 shows power plant dispatch of the scenarios without electric vehicles for 2020, the 2030 baseline, and the 2030 RE$^+$ sensitivities. Between 2020 and 2030, generation from wind and PV as well as CCGT plants increases, as the respective capacities grow (cf. Figure 4.1). On the contrary, generation from lignite and hard coal goes down and nuclear power is phased out completely

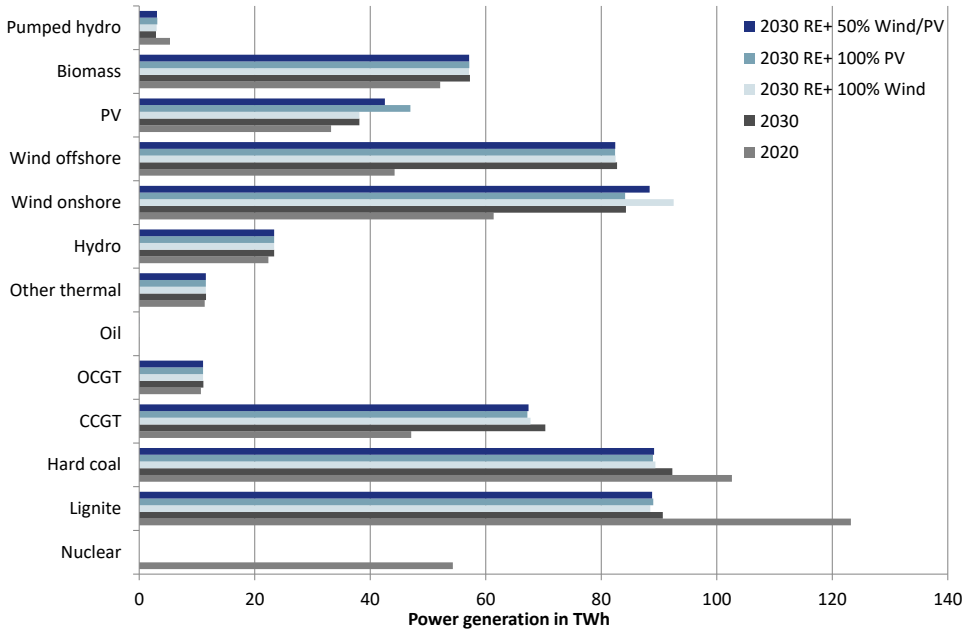


Figure B.1.: Dispatch outcomes for scenarios without EVs. Source: Own calculations.

B.3. Sensitivity analyses

Results of dispatch models generally depend on the input parameters used. This concerns, for example, assumptions on the power plant fleet, future CO_2 prices, and power exchange with neighboring countries. In fact, the uncertainties concerning the future development of the German power plant portfolio may be larger than the size of the EV fleet assumed here. We thus carry out additional sensitivity analyses for the year 2030 to study the effect of such parameter variations.

Two sensitivities deal with changes of the power plant fleet: "No lignite" assumes that all lignite plants are shut down by 2030 and fully substituted by CCGT plants with block sizes of 500 MW each. This sensitivity is of interest against the background of the ongoing debate on the compatibility of lignite-fired power generation with German CO_2 emission targets. In a sensitivity "20% more RES," we assume the capacities of onshore and offshore wind power as well as PV to be 20% larger compared

to EM^+. This assumption reflects the fact that renewable expansion was much faster in the last decade compared to what was planned by the government.[88] In another sensitivity called "Double CO_2 price" we assume that CO_2 prices double compared to what is assumed in EM^+ for 2030, i.e., reach 82 €/t. A fourth sensitivity deals with the simplifying assumption of treating the German power system as an island: In "Exchange", we fix the hourly net power exchange with neighboring countries to 2010 levels. The respective time series is derived from data published by the four German transmission system operators.[89]

For each of these sensitivities, we carry out three model runs: a reference case without electric vehicles, a fully user-driven case, and a fully cost- driven one. We then compare dispatch outcomes of the EV scenarios to the respective runs without EVs. Results presented in Figure B.2 shows that major changes of general dispatch outcomes occur only under the assumption of double CO_2 prices.

In "No lignite", additional generation from hard coal and CCGT plants substitutes for the phased-out lignite plants. The relative share of CCGT under the cost-driven charging mode is higher than in EM^+, as the hard coal plants are often producing at full capacity even in the case without EVs. Accordingly, specific CO_2 emissions of EVs also decrease compared to EM^+. Yet the general finding that cost-driven charging involves more power generation from emission-intensive coal plants and less from CCGT compared to user-driven charging also holds in this sensitivity.

A major change occurs in the sensitivity "Double CO_2 price." Under this assumption, the merit order changes such that CCGT plants provide the cheapest option to charge EVs. Accordingly, CCGT is now the predominant source of charging electricity in the cost-driven mode, while lignite and hard coal achieve only minor shares. In contrast, user-driven charging now involves larger amounts of electricity from lignite and hard coal plants, as cheaper CCGT plants are already producing at full capacity in many hours of vehicle charging. This sensitivity also indicates that cost-driven charging goes along with less carbon-intensive power generation if CO_2 is priced sufficiently.

In the "20% more RES" sensitivity, results generally do not change much compared to EM^+. EVs lead to some additional integration of wind power and PV; yet most of the charging electricity still comes from lignite and hard coal plants in the cost-driven mode, and from hard coal and CCGT plants in the user-driven mode, respectively.

[88] In contrast to the RE^+ scenario, we do not link the renewable expansion to the introduction of electric vehicles, i.e., the additional renewable capacities are also foreseen in the respective reference scenario without electric vehicles.

[89] We chose the year 2010 because it is consistent with the load data and the renewable feed-in patterns. According to data provided by 50Hertz, Amprion, TenneT TSO, and TransnetBW, net exports amounted to around 5 TWh in 2010, with hourly maximum net exports of 6 GW and maximum net imports of 7 GW.

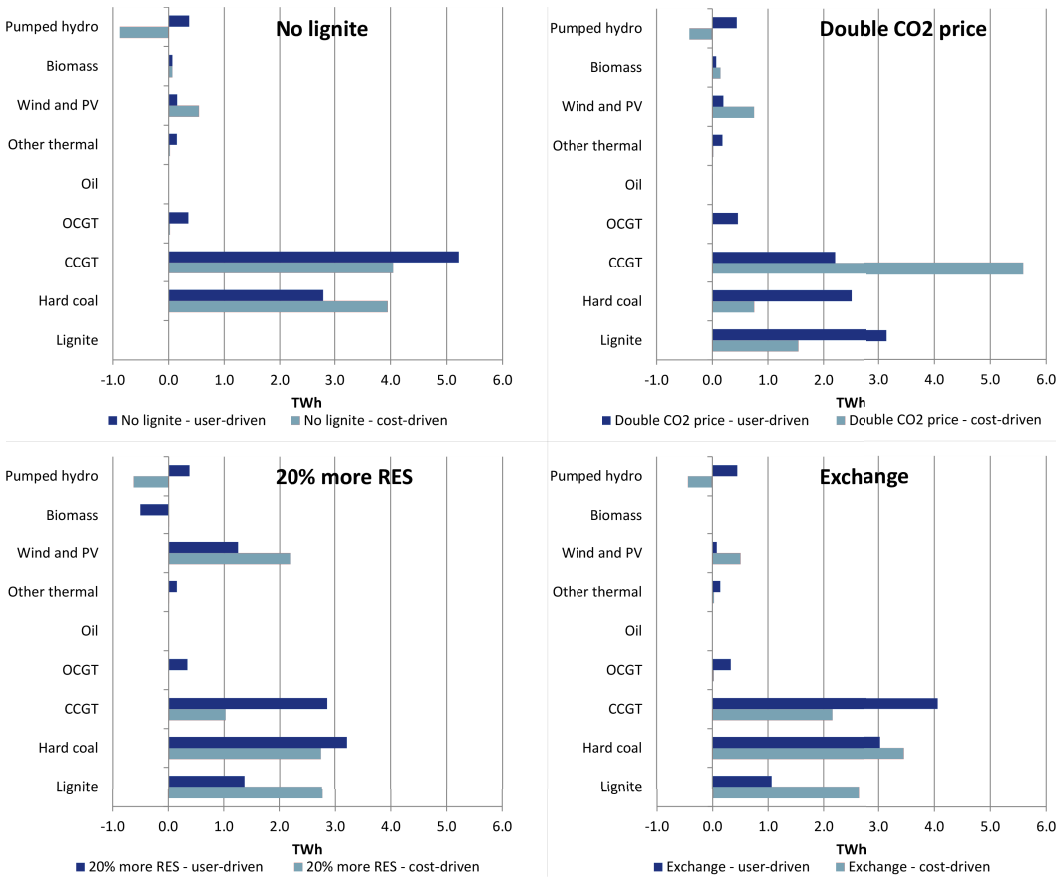


Figure B.2.: Sensitivity analyses: dispatch changes relative to respective scenarios without EVs.

The reason is that most of the additional renewable power is already used in the reference scenario without electric vehicles.

Finally, "Exchange" only leads to minor changes compared to EM^+. Assuming hourly net power exchange with neighboring countries as in 2010 leads to slightly higher full-load hours of lignite and hard coal plants compared to EM^+ already in the case without electric vehicles. The effect of EV charging on lignite is thus mildly mitigated: in the cost-driven mode, charging power from lignite now amounts to 2.6 TWh, compared to 2.9 TWh in EM^+. Yet the overall change remains small because of the rather low historic exchange levels. The effect should become stronger if further renewable expansion in Germany, combined with increased interconnector capacity, leads to higher cross-border power exchange.

Appendix C

Appendix to Chapter 6: Is there still a case for merchant interconnectors?

C.1. Nomenclature

Sets

bz, bzz	Bidding zone
l	Lines in the electric grid
lm	Subset of l, merchant lines
lr	Subset of l, regulated lines
n, nn	Node
s	Power plant technology
t	Hour

Parameters

B_l	Line susceptance
C_s	Marginal production cost of plant type s
$D_{n,t}$	Residual demand at node n in t
$Exp0_l$	Initial line expansion level
$\overline{Exp_l}$	Maximum expansion level of line l
$F_l^{\max}$	Thermal limit of existing line l
$Hflf_{bz}$	Hydro full load factors, by bz
I_l	Investment cost per MW on line l
$Inc_{l,n}$	Incidence matrix
M_l^{ζ}	Upper bound on line due to parallel line limits
$Q_{s,n}^{\max}$	Maximum generation of plant s at node n
$Slack_n$	Slack bus
W_t	Relative weight of hour t

Variables

$\delta_{n,t}$	Phase angle
$\zeta_{lr,t}$	Flows through endogenously added AC lines
$\zeta_{lm,t}$	Flows through DC lines
exp_l	Expansion on line l
$p_{n,t}$	price at node n in t
$pD_{lm,t}$	Price difference on merchant lines in t
$q_{s,bz,t}$	Generation of plant s in bidding zone bz in t

C.2. Rents and costs of Stackelberg, AC Only and Fully Planned Cases

Table C.1.: Rents and costs, in mn € p.a. Investment costs are the respective annuities.

	Rents				Costs		
	Producers	Consumers	AC Congestion	DC Congestion	DC Investment	AC Investment	Generation
AC Only	74,439	265,994	1,120	0.00	0.00	211	46,404
Stackelberg	74,577	265,940	1,037	39.59	8.16	199	46,367
Fully Planned	75,399	265,215	978	18.61	24.13	187	46,346

Source: Own calculations.

C.3. Flow limits due to network topology

The following considerations are inspired by Taylor and Hover (2011).

Step #1. A power flow f_l on a line l, connecting nodes 1 and 2, with voltage angles δ_1, δ_2 respectively, line series susceptance B_l and constrained by the ampacity-based flow limit $F_{\max,l}$ is subject to the following relations:

$$|f_l = B_l(\delta_1 - \delta_2)| \leq F_{\max,l} \tag{C.1}$$

$$\Rightarrow \quad |\delta_1 - \delta_2| \leq \frac{1}{B_l} F_{\max}. \tag{C.2}$$

If we now assume a continuous line expansion such that the new line has now Δ times of its original susceptance and ampacity (C.2) still holds true:

$$|f_l = \Delta B_l(\delta_1 - \delta_2)| \leq \Delta F_{\max,l} \tag{C.3}$$

$$\Rightarrow \quad |\delta_1 - \delta_2| \leq \frac{\cancel{\Delta} 1}{\cancel{\Delta} B_l} F_{\max,l} \tag{C.4}$$

Thus, (C.1)=(C.4) and we have a limit on angle-differences along lines that is independent of the expansion factor Δ of the line, but only depends on its physical characteristics.

Step #2. Further to that, direct-current load flow (DCLF) requires that the sum of angle differences summed up along each closed mesh is 0. This is illustrated in Figure C.1, which depicts a sample meshed network. It immediately follows that

$$0 = (\delta_2 - \delta_1) + (\delta_3 - \delta_2) + (\delta_4 - \delta_3) + (\delta_5 - \delta_4) + (\delta_1 - \delta_5). \tag{C.5}$$

However, as we see in Step #1, the angle differences along each line l are subject to a general limit that emerges from the physical line characteristics (C.4), independent

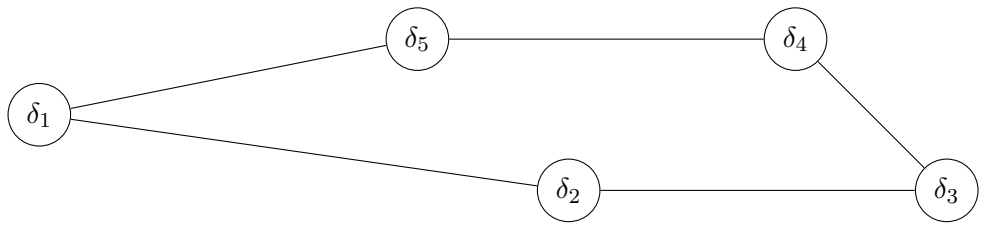


Figure C.1.: Sample meshed network
Nodes n labeled with their respective voltage angle δ_n. Source: Own depiction.

of any level of line expansion. As (C.5) must hold, (C.4) is not necessarily sufficient: Any angle difference on a line l is constrained by the shortest path of voltage-angle difference limits. Therefore, (C.4) can, without any loss of generality, be replaced by

$$|\delta_1 - \delta_2| \leq \min \{M_{\zeta,\mathrm{sp},l}, F_{\mathrm{max},l}\} B_l^{-1}, \tag{C.6}$$

where $M_{\zeta,\mathrm{sp},l}$ is the shortest path between nodes 1 and 2, measured by the sum of maximum angle difference limits. I.e. (C.6) is a valid constraint on line angle differences, independent of network expansion state, but only **depending on physical characteristics of the line itself and on network topology**. $M_{\zeta,\mathrm{sp},l}$ can thus be calculated by a shortest-path algorithm, such as the Dijkstra-algorithm (Dijkstra, 1959).

C.4. Background on merchant interconnectors in Europe

Investments in electricity grid infrastructure, as well as increased competition, are an important element in the development of the internal energy market that the European Commission (EC) seeks to promote. EC regulation 714/2009 (EC, 2009e) allows exemptions from certain aspects of the regulation for investments in cross-border lines in order to stimulate investments that would not occur due to excessively high risk were exemptions not in place. When building electricity grids, costs are generally sunk and not recoverable. The risks potential investors face may include a change in the cost and revenue structure, as described in (EC, 2009b). This might be caused by regulatory uncertainty, especially when more than one regulator is involved or when technological risk is high. Therefore a potential investor may be allowed an exemption from parts of existing regulation.

A full exemption frees the interconnector from the obligation to third party access and enables the owner to set fees and tariffs that are used to earn revenues through congestion rents. Equivalently, the owner might be able to withhold capacity in order to increase the congestion rents.

These exemptions may be granted by the National Regulatory Authorities (NRAs) for a limited time and are reviewed by the EC if more than one Member State is involved in granting the exemption following amongst other things these rules:

- the investment needs to increase competition;
- the risk involved necessitates the exemption; and
- the exemption must not hinder the functioning of the internal market and the regulated system.

An analysis of the four exemption decisions by the EC since 2005 is conducted by Cuomo and Glachant (2012). The authors observe a recent tightening of the exemption regime by not granting full exemptions and imposing additional requirements on cross-border interconnector development. The EC has made decisions for the following cases:

- Estlink, a 350 MW high-voltage direct current (HVDC) cable between Estonia and Finland, commissioned in 2006;
- BritNed, a 1 GW HVDC cable connecting the British and Dutch grids, commissioned 2011;
- East–West Cable One, a 350 MW HVDC cable connecting Great Britain and Ireland, delayed; and
- Arnoldstein/Tarvisio, a 132 kV, 160 MW alternating current (AC) line between Austria and Italy, commissioned 2012.

The decision by the NRAs allowing EstLink an exemption from tariff regulation and third party access was confirmed by the EC in 2005 (EC, 2005). For BritNed, the exemption was approved in 2007, but due to concerns regarding a possible undersizing of the interconnector's capacity, the obligation to present a financial report 10 years into the interconnector's operation was added. If the revenues were to exceed the expectations, the NRA could introduce a profit cap or require BritNed to increase capacity (which would not be covered by the exemption) in order to reduce congestion rents (EC, 2007). The exemption for the East-West Cable was confirmed by the EC in 2009 as the risk involved in the project was deemed sufficient due to the planned competing regulated 500 MW interconnector EirGrid (EC, 2008c). The approval was linked to the commissioning of EirGrid and also included conditions regarding congestion management and trading. The project is currently delayed. The EC decided in 2010 that the exemption for the AC overhead interconnector Arnoldstein-Tarvisio would be granted, but no exemption from third party access

would be given. Furthermore all increases in capacity had to be approved by the EC (EC, 2010).

Furthermore NorGer KS, the company in charge of the development of the NorGer cable between Norway and Germany, applied in March 2010 for an exemption for 25 years and full capacity of the planned cable (1,400 MW). The project fulfilled the requirements of being a new interconnector between states (Norway being on a par with Member States (Hansen, 2012)), expected enhancement of competition, investment risk and no harmful effects to the market according to the German regulatory authority BNetzA. The exemption was granted by BNetzA in 2010 (BNetzA, 2010). Because the EC's risk assessment showed that the interconnector might still be built without exemption and Norway's preference for a regulated interconnector, NorGer KS withdrew the application in April 2011 (Askheim, 2012).

C.5. Identification of reference hours

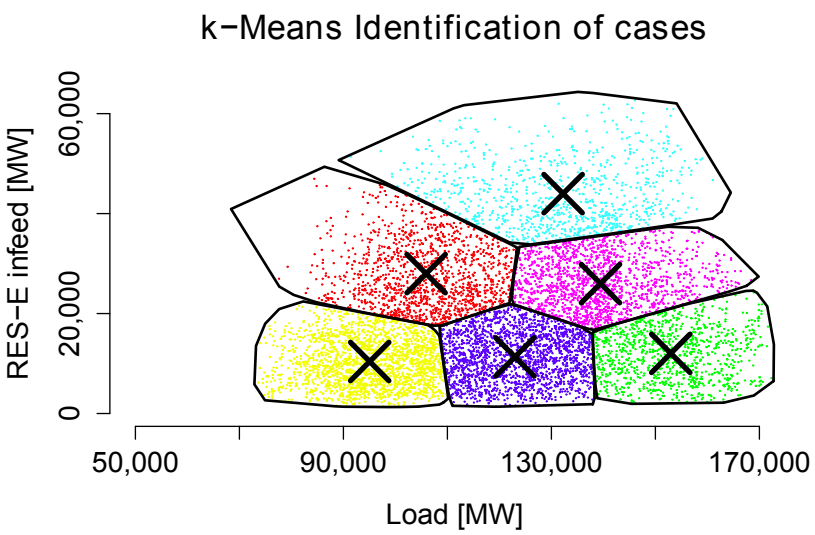


Figure C.2.: Example identification of Reference Hours. Cluster Centers are located at the crosses. Source: Own Calculations.

Due to limits in computational power, it is not feasible to calculate the mathematical problem with equilibrium constraints (MPEC) for, e.g. a full year of 8760 hours. However, due to the periodicity of load and, partly, intermittent renewables feed-in, we use reference hours. The approach to use reference hours, or reference cases is widespread in modeling. However, identifying the reference cases is often done by using the modeler's intuition. In order to formalize this process, we apply a so-called k-means clustering process to the data, as e.g. Green et al. (2014) propose: We group

the hours into N groups such that in-group variance is smallest. The data we use here is two-dimensional: We have electric load and intermittent feed-in (Wind and PV). The clustering process is done using R Core Team (2012).

Figure C.2 shows the result of the clustering process for $N = 6$. The resulting clusters are not necessarily of the same size; therefore, we take into account the cluster size as a relative weight for the respective reference hours.

C.6. AC expansion figures

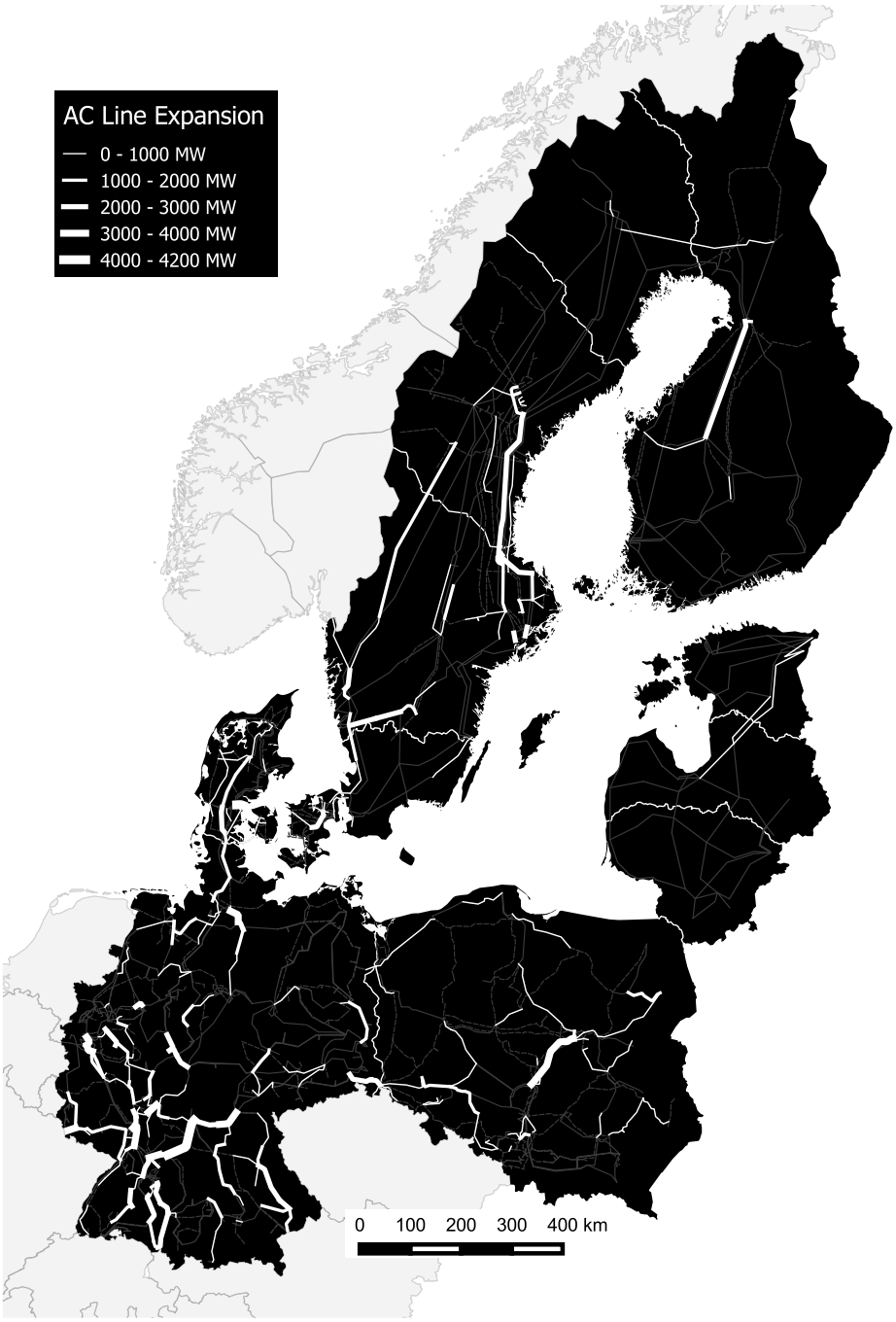


Figure C.3.: AC grid expansion in the *AC Only* scenario. Source: Own calculations.

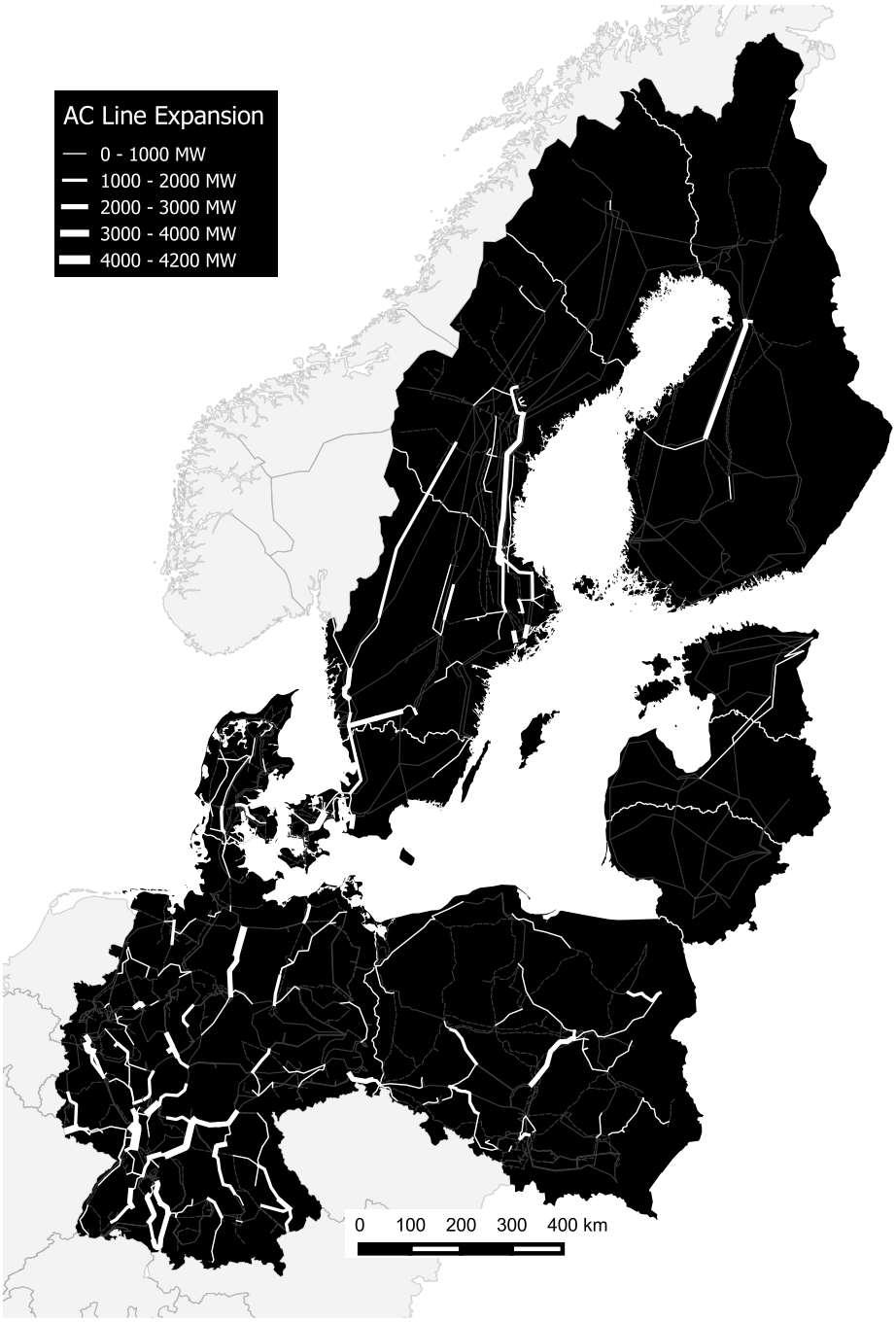


Figure C.4.: AC grid expansion in the *Stackelberg* scenario. Source: Own calculations.

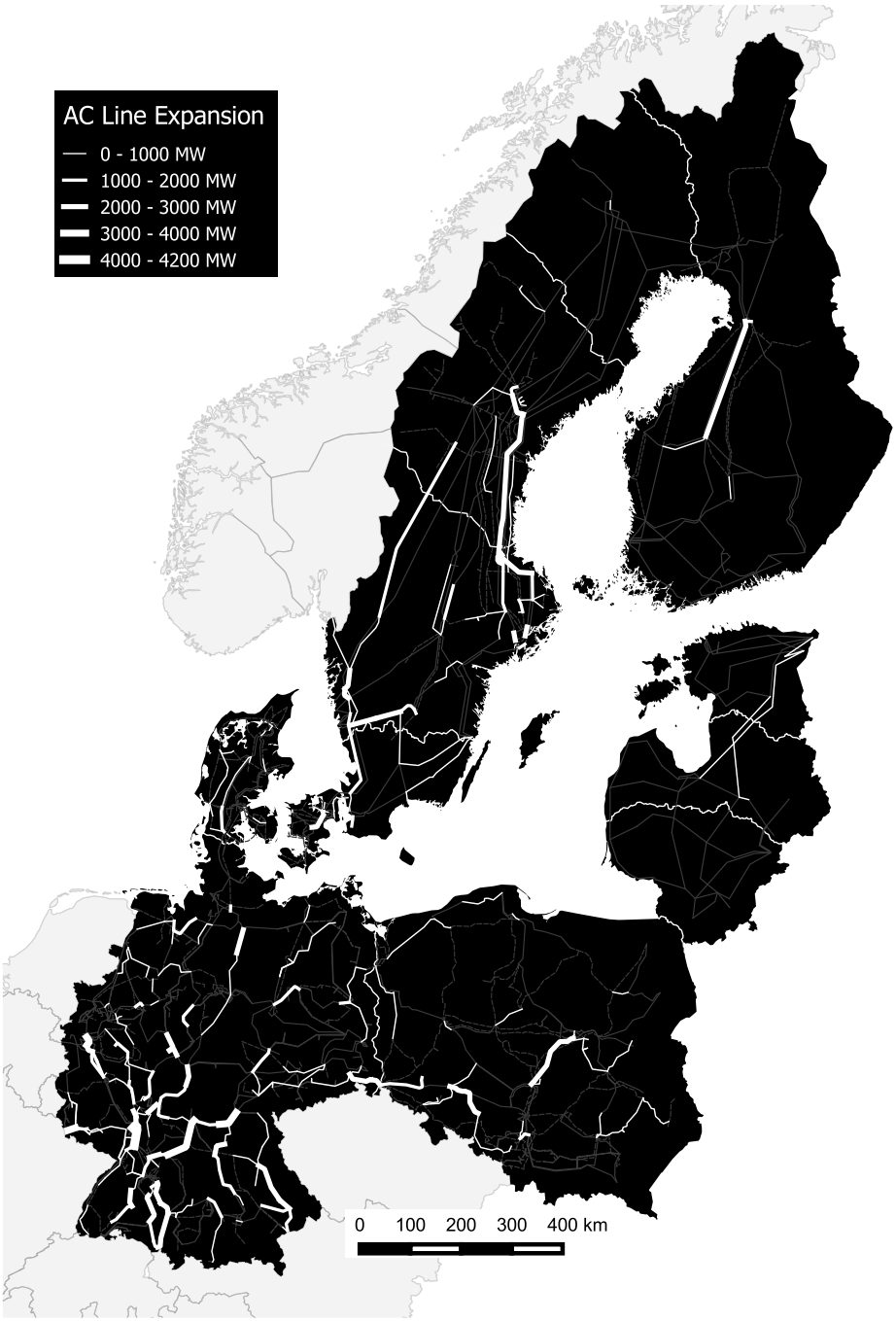


Figure C.5.: AC grid expansion in the *Fully Planned* scenario. Source: Own calculations.

Appendix D

Appendix to Chapter 8: A dynamic investment and dispatch Model (dynELMOD)

D.1. Nomenclature

Table D.1.: Sets in dynELMOD

Sets	
p	Power plant
f	Fuel
i	Generation technology
$c(i)$	Conventional technology
$disp(i)$	Dispatchable technology
$ndisp(i)$	Non-dispatchable technology
$s(i)$	Storage technology
$dsm(i)$	DSM technology
t, tt	Hour
y	Calculation Year
yy	Investment Year
$co, cco, ccco$	Country

Table D.2.: Variables in dynELMOD

Variables	
$cost$	Objective value: total cost
$cost^{gen}$	Variable generation cost
$cost^{inv}$	Investment in generation capacity
$cost^{cap}$	Fixed generation capacity cost
$cost^{line}$	Line expansion cost
$g_{co,i,t,y}$	Sum of existing and newbuilt electricity generation
$g^{existing}_{co,i,t,y}$	Generation of existing technology
$g^{newbuilt}_{co,i,t,y,yy}$	Generation of new built technology
$g^{up}_{co,i,t,y}$	Upward generation
$g^{down}_{co,i,t,y}$	Downward generation
$g^{instcap}_{co,i,y}$	Installed generation capacity
$inv^{cap}_{co,i,yy}$	New generation capacity
$inv^{stor}_{co,i,yy}$	New storage capacity
$inv^{line}_{y,co,cco}$	Grid expansion
$ni_{co,t,y}$	Net input from or to network in country
$dcflow_{co,cco,t,y}$	HVDC flow between countries
$flow_{co,cco,t,y}$	Flow between countries in NTC aproach
$stor^{level}_{co,i,t,y}$	Storage level
$stor^{loading}_{co,i,t,y}$	Storage loading
$stor^{release}_{co,i,t,y}$	Storage release

Table D.3.: Parameters in dynELMOD

Parameters	
$Ava_{co,i,y}$	Average annual availability [%]
$CarbonRatio^{emission,new}_{co,i,yy}$	Carbon emission ratio of newbuilt capacities
$CarbonRatio^{emission}_{p,co,i,y}$	Carbon emission ratio of existing capacities
$CarbonRatio^{sequestration,new}_{co,i,yy}$	Carbon sequestration ratio of newbuilt capacities
$CarbonRatio^{sequestration}_{p,co,i,y}$	Carbon sequestration ratio of existing capacities
$CCTSStor^{Capacity}_{co}$	CO_2 storage capacity
$Cfix_{co,i,y}$	Fix generation cost [EUR per MW]
$Cinv^{stor}_{i,y}$	Annuity of storage investment [EUR per MWh]
$Cinv_{i,y}$	Annuity of investment [EUR per MW]
$Cline_{y,co,cco}$	Line expansion cost [EUR per (km and MW)]
$Cload_{co,i,y}$	Load change cost [EUR per MWh]
$Cvar^{newbuilt}_{co,i,y,yy}$	Variable cost of new built technology [EUR per MWh]
$Cvar_{co,i,y}$	Variable cost of existing technology [EUR per MWh]
DF_y	Discount factor for each year
$Emissionlimit_y$	Yearly CO_2 emission limit
$\eta^{existing}_{p,co,i,y}$	Thermal efficiency of existing technology [%]
$\eta^{newbuilt}_{p,co,i,y}$	Thermal efficiency of newbuilt technology [%]
$\eta^{storage}_{co,i,y}$	Storage efficiency [%]
$G^{max\_installed}_{co,i,y}$	Maximum installable capacity [MW]
$G^{max\_inv}_{co,i,y}$	Maximum investment per time period [MW]
$G^{max}_{p,co,i,y}$	Maximum generation of existing capacities [MW]
$G^{min\_CHP}_{p,co,t,i}$	Minimum generation induced by CHP constraint [MW]
$Gen^{max}_{co,f,y}$	Availability of fuel f [MWh_{th}]
$HVDC^{max}_{co,cco}$	Maximum existing HVDC transmission capacity [MW]
$Inflow_{co,s,y,t}$	Inflow into reservoirs or other storages [MW] $NTC_{co,cco}$
NTC between countries	
$P^{max}_{co,cco}$	Maximum existing AC transmission capacity [MW]
$PTDF_{co,cco,ccco}$	Country-sharp power transfer distribution matrix
$Q_{co,t,y}$	Electricity demand [MWh]
$R^{down}_{i,y}$	Ramping down [% per hour]
$R^{up}_{i,y}$	Ramping up [% per hour]
$ResAva^{existing}_{co,t,i}$	Renewable vailability of existing capacities [%]
$ResAva^{newbuilt}_{co,t,i,y}$	Renewable vailability of newbuilt capacities [%]
$Storage^{maxlevel}_{co,i,y}$	Maximum storage level of existing capacities [MWh]
$Storage^{maxloading}_{co,i,y}$	Maximum storage loading of existing capacities [MW]
$Storage^{maxrelease}_{co,i,y}$	Maximum storage release of existing capacities [MW]
$Storage^{minlevel}_{co,i,y}$	Minimum storage level of existing capacities [MWh]

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