UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER DEGREE IN THE

ELECTRIC POWER INDUSTRY

Master's thesis

MODELLING OF THE ECONOMIC FEASIBILITY OF LARGE-SCALE ELECTRICITY STORAGE TECHNOLOGIES: A GERMAN CASE STUDY

Author: **Wouter Schoof**

Supervisor: **Wim van der Veen (DNV GL Energy)**

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Official Master's Degree in the Electric Power Industry (MEPI)
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Thesis study for the MSc. Electric Power Industry by Wouter Schoof

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Summary

Electricity storage is often portrayed as the solution for the challenges that an increasing capacity of intermittent generation brings. If the electricity storage facilities are to be introduced in the grid by private investors though, just like any other asset, they require a business case. This study is part of the DNV GL StRe@M project whose goals include the modelling of the economic feasibility of electricity storage facilities in future German electricity grid scenarios from a price-taking investor's perspective by comparing costs and revenues. The two revenue streams considered in the StRe@M project come from the spot and reserve market, and this study focuses on modelling the latter for Germany. This thesis also provides a cost and revenue framework to assess the revenues from both markets and the resulting profits. First a qualitative study maps the German reserve market and the characteristics of its products to identify opportunities for electricity storage and the impacts of regulation thereon. Next a quantitative model is designed to assess the revenue potential of the future secondary reserve market by forecasting its demand and price levels. The modelling scope is limited to the secondary reserve (energy) market (named *aFRR* in Germany) only because of its relative market size, the low number of participants and data availability. A bottom-up approach was tried by looking for a quantified relation between (1) historical time series of forecast errors for load and solar and wind generation and (2) system imbalances or activated aFRR directly – a positive causal relation which often appears in literature. As no quantified relation could be found an alternative top-down stochastic approach then used the historical probability distribution of activated aFRR in 2015 to establish a stochastic function for aFRR demand in future scenarios up to a few years, preserving the properties of the historical probability distribution. An effort was made to scale this stochastic function for an increasing renewable penetration but no workable scaling could be obtained. The future prices to accompany the forecasted volumes were determined from a regression analysis on historical aFRR price time series. Regression components included the aFRR volume and the spot price. The design of the cost and revenue framework, used to process the potential revenues from the spot and reserve market, was based on comparing samples of a stochastic reserve market revenue with a deterministic spot market revenue and aggregating this into a distribution for the profit. To conclude the first dispatch and profit results of the StRe@M modelling are presented for a German electricity scenario in February 2020 with an 80% RES share, which should be used with great caution. The modelled lithium-ion battery technology and variable-speed PSH show positive profits on average, but the fixed-speed PSH does not. The main limitation of this model is the lack of the scaling effect for renewable penetration, for which a scenario analysis is probably most suited.

Acknowledgements

This thesis study was commissioned by DNV GL Energy in the Netherlands. I would like to thank the entire Market and Policy Development team at the Arnhem office for welcoming me in their team, introducing me to their business and providing me with guidance and advice. A special thanks to Wim van der Veen, Pieter van der Wijk and Henk Koetzier who closely worked with me on the StRe@M project.

In addition, I want to thank Lisanne, my family and friends for their support and love. It means the world to me.

“Perfect is the enemy of good”

- Voltaire

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List of Acronyms

aFRR	Automatic frequency restoration reserve
BKartA	Federal Cartel Office (*Bundeskartellamt*)
BMUB	Federal Ministry for the Environment, Nature Conservation, Building and Nuclear safety (*Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit*)
BMWi	Federal Ministry of Economic Affairs and Energy (*Bundesministerium für Wirtschaft und Energie*)
BNetzA	Federal Network Agency (*Bundesnetzagentur*)
CAES	Compressed-air-energy-storage
CHP	Combined heat and power
DAM	Day-ahead market
DSO	Distribution system operator
EEG	Renewable Energy Act *(Erneuerbare Energien Gesetz)*
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Industry Act (*Energiewirtschaftsgesetz*)
FCR	Frequency containment reserve
FiT	Feed-in tariff
FS-PHS	Fixed speed pumped hydro storage
FRR	Frequency restoration reserve
GCC	Grid Control Cooperation
GW	Gigawatt
GWh	Gigawatt-hour
IGCC	International Grid Control Cooperation
IRRE	Insufficient ramping resource expectation
ISO	Independent system operator
ITO	Independent system operator
KW	Kilowatt
LAES	Liquid-air-energy-storage
LCOE	Levelized cost of energy
mFRR	Manual frequency restoration reserve
MW	Megawatt
MWh	Megawatt-hour
PDF	Probability density function
PSH	Pumped-storage hydroelectricity
PTU	Per-time unit
PV	Photo voltaic
reBAP	Imbalance price (*Bilanzausgleichsenergiepreis*)
RES	Renewable energy source
RR	Replacement reserve
TSO	Transmission system operator
VS-PHS	Variable speed pumped hydro storage

Chapter 1. Introduction

1.1. Electricity storage investment opportunity

Energy storage is often portrayed as the ideal solution for increasing the capacity of intermittent generation that an electricity grid can successfully adopt. Adding the function to the grid of transferring energy in time, which energy storage could provide, would make it possible to overcome the fluctuating outputs of intermittent renewables. There is no consensus in the literature though about with what level of renewable penetration electricity storage is actually required in an electricity grid. Numbers vary from 20% to beyond 60% measured as share of production and share of installed capacity (DLR et al, 2012; IRENA, 2015; Martinot, 2015). Wind and solar PV generation, the two biggest intermittent renewable generation sources, had annual capacity growth rates of 40% and 160% respectively between 2006-12 (IRENA, 2015) though.

As a result, regulators, utilities, and private investors in many countries have been exploring how electricity storage can provide value to their respective electricity grids at large-scale and by how much. In the liberalized markets the potential deployment of electricity storage technologies will, at least partially, be left to the market though. Because just like any other asset, electricity storage facilities require a business case, private investors are looking for opportunity and business analyses of the economic feasibility of electricity storage facilities to guide and help with investment decisions (CitiGroup, 2015). Economic feasibility in this case refers to the assessment of monetary benefits and costs, to clearly distinguish from the term value, which can also be considered to entail non-monetary costs and benefits or factors that are difficult to express in monetary terms.

With all the uncertainty in the electricity markets assessing the economic feasibility is not a clear-cut analysis at all. Lifetimes of most storage technologies are long enough to live through many regulatory and market changes. The recent plans to evoke the operating licences of still-operating nuclear plants in Germany or coal plants in The Netherlands are showcases of this regulatory uncertainty (Agora, 2015). Billions were invested in these plants, of which some are only a few years old, and it will cost both operators and taxpayer billions to close them. Experiences like this will not contribute to making any investor eager to start new large energy projects.

The uncertainty is not just limited to regulations, also the future revenue streams of deploying any electricity asset, including storage, are difficult to forecast. The many markets these facilities could participate in would have to be sized and assessed. If electricity storage can provide any important function to the grid markets should be able to adequately reward this. Governments would have to

take an active role in clearing obstacles for electricity storage facilities and regulations and facilitate market models that allow electricity storage to be valued appropriately if they are to enter electricity industries in high volume and can contribute in any way to the adoption of increasing intermittent generation.
The question of how the economic feasibility of adding a large-scale electricity storage facility to an electricity grid from a price-taking investor's perspective can be assessed is central in this thesis study.

1.2. Current feasible large-scale electricity storage technologies

The economic feasibility of electricity storage is to large extend determined by the technology, or mix of technologies, used in a facility as this determines in what way the facility can be operated and deployed in electricity markets. Recent technological advances in electricity storage technologies have resulted in several technologies suited for large-scale use today, which can roughly be categorized in five categories based on the type of energy they store the electrical energy in or on the storage process. Table 1 provides an overview of these five categories and their respective quantities of installed capacity in the European grid. Although there is no single definition of large-scale generation it generally refers to facilities with a minimum size, i.e. over a MW or so, and connection to the transmission grid.

Table 1 – Categories of feasible large-scale electricity storage technologies and their installed capacities in the European electricity grid. The data only includes grid-scale deployments (ESU, 2015).

Electricity storage technology category	**Description**	**Installed in Europe** [MW]
Pumped-storage hydroelectricity (PSH)	Energy is stored in a hydro reservoir as potential gravitational energy. The pump system can have either a single fixed speed/frequency, referred to as fixed-speed PSH or FS-PSH, or a variable speed/frequency, referred to as variable-speed PSH or VS-PSH.	63.142
Electro-mechanical	Energy is stored as mechanical energy. Includes storage technologies like flywheels.	1.384
Thermal storage	Storing energy as heat or pressure. Thermal storage technologies include Compressed-Air-Energy-Storage (CAES) and Liquid-Air-Energy-Storage (LAES)	1.171
Electro-chemical (battery)	Storage based on an electro-chemical reaction. Includes battery technologies like lithium-ion and vanadium redox.	187
Hydrogen storage	Storage based on turning electrical power into hydrogen gas through rapid response electrolysis. Conversion from gas back to electricity can be done through gas-based generation plants. This technology is also referred to as power-to-gas.	5

The only large-scale electricity storage category widely deployed today is PSH. This technology is based on a pumping system that turns electricity in potential gravitational energy by transferring water to higher elevated reservoirs. As PSH has been around for a while, it also only one of the few mature technologies, meaning that it is has been in operation sufficiently long for inherent faults and inefficiencies to have been reengineered. Other electricity storage technologies are still very much under development (Deloitte, 2015).

Table 2 provides a selection of four electricity storage technologies used in large-scale storage facilities today and their (typical) technical characteristics. The power rating refers to the potential efficient sizes of storage facilities equipped with the specific technology. Looking at Table 2 it becomes evident that the different technical characteristics of electricity storage technologies influence the ways they can be deployed in the grid and create value. The difference in both power and energy density between PSH and battery technologies is immense which can be a determining factor when physical space is limited. Battery technologies on the other hand, both lithium-ion and vanadium redox flow, make use of electro-chemical reactions to store energy which results in extremely high response times and ramp rates, meaning they can increase or decrease their generation output in a short period of time, but they have a limited lifetime compared to PSH.

Table 2 – Electricity storage technologies available for large-scale deployment and a selection of (typical) technical characteristics (Deloitte, 2015).

Energy storage technology	**Power rating** [MW]	**Life time**	**Energy density** [Wh/l]	**Power density** [W/l]	**Response time**	**Efficiency** [%]
Pumped Hydro Storage (PHS)	100-1000	30-60 years	0.2-2	0,1-0,2	sec-min	70-85
Compressed-Air-Energy-Storage	10-1.000	20-40 years	2-6	0,2-0,6	sec-min	40-75
Lithium-ion battery	0,1-100	1.000-10.000 cycles	200-400	1.300-10.000	10-20 ms	85-98
Vanadium redox flow battery	0,1-100	12.000-14.000 cycles	20-70	0,5-2	10-20 ms	60-85

1.3. The value of electricity storage

1.3.1. System versus investor perspective

The value of adding an electricity storage facility to the grid depends on the owner's perspective, which can be roughly categorized in two perspectives. The first perspective is concerned with the system as whole, and is referred to as the central-planner perspective. A central-planner aims to minimize the total cost of the electricity system and supply and thereby maximizes the so-called total net benefit for society taking into account reliability and quality levels. Ways in which value can be created for a central-planner include bringing down the overall costs of supply, saving on transmission expansions or upgrades but also mitigating environmental impacts of the electricity industry (NREL, 2013). The second perspective is that from a private investor. An investor strives to maximize its profits and not so much to minimize system costs. Hence deploying electricity storage to save on (public) grid expansion does not make much business sense for an investor. Ways in which private investors and operators in electricity storage facilities can make profit include arbitrage on the energy markets, buying when the price is low and selling when the price is high, mitigating supply risks by limiting the resource dependency of their generation portfolios or by saving on private grid infrastructure (NREL, 2013). The focus of this thesis study will be on the investor's perspective when assessing the economic feasibility of electricity storage technologies.

1.3.2. Deployment alternatives

The way electricity storage is deployed in an electricity grid determines the way value can be created. There are several deployment alternatives for electricity storage facilities, for which Figure 1 provides an overview.

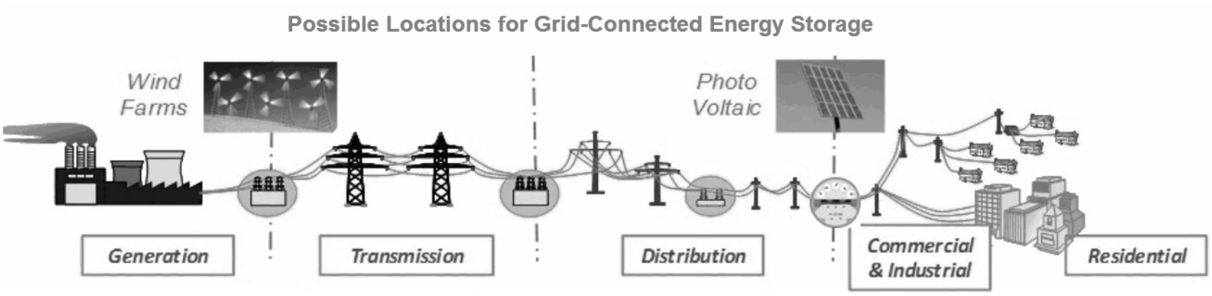

Figure 1 - Different deployment alternatives for electricity storage (Green Energy Storage, 2015).

When electricity storages facilities are deployed near transmission or distribution lines it can be used to level out electricity flows by shifting them in time, thereby mitigating congestion and potentially avoiding necessary grid expansions. When electricity storage is deployed near load, like at the houses of private consumers or even at the sites of large industrials, it can help to flatten demand. At times when electricity is cheap the storage capacity can consume electricity for storage only to use it later on when the electricity is needed or return it to the grid when demand and prices are high and profit from the arbitrage. Deployment near electricity generation facilities allows generation operators to realize a stable and constant output by storing electricity when it is abundantly available and deliver it to the grid when a supply deficit looms threatening delivery agreements. This is particularly interesting for operators for operators of intermittent renewable generation as it mitigates the risks associated with the uncontrollability of the output.

1.3.3. Application alternatives

The deployment alternative, combined with the operators' perspective and interest and the storage technology determine how electricity storage facilities could or are be operated in an electricity grid. Figure 2 provides an overview of the applications of electricity storage facilities in the German electric power industry. Only grid-scale technologies with a storage capacity larger than 1 MWh are included. The application of frequency regulation, one of the ancillary services of an electricity grid, is by far most popular.

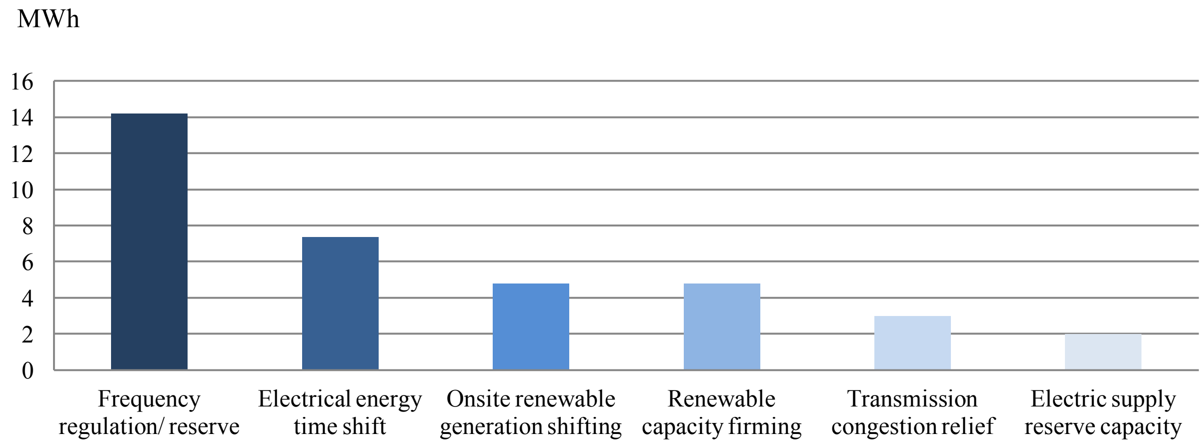

Figure 2 - Applications of electricity storage on grid-scale in the German electricity grid in 2015 (ESU, 2015). Only installation capacities larger than 1 MWh are included.

1.2.4. Country specificity

The value of adding electricity storage to a grid is also highly country specific. All the aforementioned deployments and application alternatives are subject to regulations and market mechanisms. Regulations specify what the technical requirements are for generation or storage units to participate in one of the several electricity markets. These requirements can comprise minimum facility sizes, response times or even companies' legal structures. The potential revenues to be made with price arbitrage for instance, depends heavily on market prices and its volatility specifically. Electricity regulations determine what levies or exemptions apply to electricity storage facilities and in some cases what support mechanisms are available to help the storage technology gain a competitive advantage over other technologies.

1.4. StRe@M project

1.4.1 eStorage project

Much research is being performed into the challenges that come with an increasing share of intermittent generation. In an effort to contribute to a more sustainable, renewable and reliable European electricity grid, the European Commission sponsors some of those research projects that investigate the adoption of additional intermittent renewable generation in European electricity grids. One of these projects is the eStorage project. This currently ongoing project is founded by a consortium of Imperial College London, three energy companies (General Electric/Alstom, EDF and ELIA), two consulting companies (Algoé and DNV GL, the commissioning company of this thesis study). The eStorage project investigates how renewables can be integrated in the future European electricity system in a cost-efficient way. Specifically, the project focuses on one of the barriers for cost-effective integration of intermittent renewables in the European grid, namely the securing of the necessary balancing services required for a successful adoption of additional renewable generation which will be elucidated in Chapter 2. The eStorage project investigates if and how different types of PSH technologies can be a solution to this balancing problem (eStorage, 2014). The goal of the project is to demonstrate the technical and economic feasibility of converting an existing FS-PSH facility, with a fixed generation or pump load, to one with a variable-speed technology under different scenarios for future renewable energy source (RES) shares of installed capacity. The insights obtained will be used to investigate the implications and requirements of an EU-wide rollout of this technology in order to allow the integration of a large share of intermittent renewable sources in the grid (eStorage, 2014).

1.4.2. StRe@M project

DNV GL's task within the eStorage project is to focus on the business aspect of Vs-PSH from a price-taking investor's perspective, meaning that changes in output are considered not to influence market prices. Besides from the eStorage project DNV GL is also encountering increasing interest from its industry clients towards the revenue side of emerging storage technologies. Potential developers and investors are looking to prepare business cases and for a basis for their operational software and control tools. DNV GL sees an opportunity to combine these demands with their role in the eStorage project and has formulated the in-house spin-off project named StRe@M in 2014. The final result of the StRe@M project should be a commercial tool or model that can assess the economic feasibility of

different energy storage technologies in different (national) European electricity markets for different future generation mixes´ RES shares and load scenarios. The StRe@M model should be practically applicable and be able to be used as input for investment and operational decisions.
Figure 3 shows the top-level functionality that the final version of the StRe@M model should have. The possible scenarios that should be able to modelled with a finalized StRe@M model are just preliminary, though the time scope of 2020-50 and the geographical scope covering Germany, Belgium and France will probably be maintained.

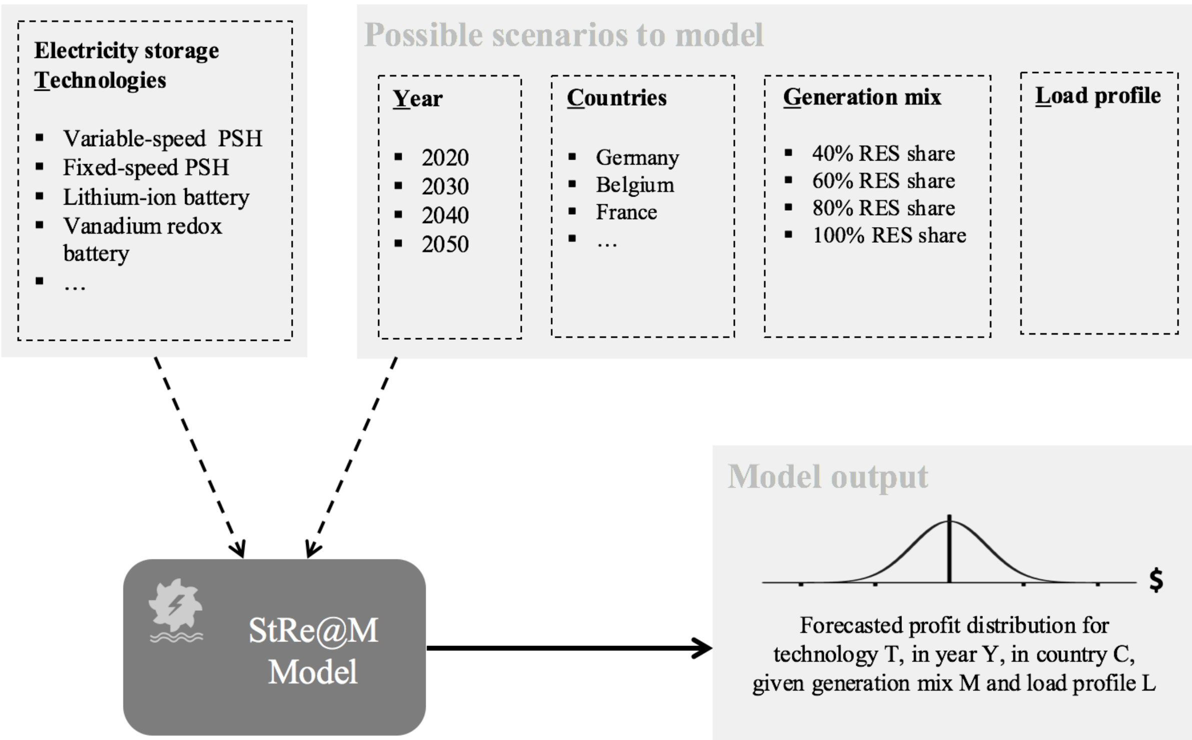

Figure 3 - StRe@M top-level functionality. A matured model would be able to estimate future profits for electricity storage technologies under different scenarios.

In order to forecast future profits, the first model will analyse two revenue streams (hence, the name StRe@M):

- Revenue from the spot market
- Revenue from the reserve market

1.5. Research objective

This thesis study is part of the initial modelling phase of the StRe@M project. The research objective of thesis study is to provide insights in the economic opportunities for electricity storage capabilities in an electricity industry and to lay a qualitative foundation for the modelling approach and methodology of the StRe@M project. In addition, the first series of modelling steps will be completed for an initial StRe@M prototype and the results will be presented along with its limitations and points of improvement.

1.6. Report outlook

This chapter has introduced the importance and challenge of determining the value of adding an electricity storage technology or facility to an electricity grid. The next chapter provides the background information on how increasing quantities of intermittent renewable generation in an electricity grid can pose challenges for a stable an reliable operation of the grid, and how this can be an opportunity for the electricity storage market. Chapter 3 then presents a literature review specifically looking at existing models for a value assessment of electricity storage technologies. Chapter 4 sets the research scope and specifies the research questions used to guide this thesis study after which Chapter 5 presents the methodology used in this study.

In Chapter 6 an overview of the German electric power industry is then presented, which forms the basis for Chapter 7 where the impacts of the German regulatory framework on electricity storage opportunities are described. Chapter 8 and Chapter 9 are devoted to the quantitative study of modelling potential future revenues in the German electric power industry and determining the potential profitability. The results and conclusion of this study will be presented in Chapter 10 and Chapter 11 respectively.

Chapter 2. Background: Increasing renewables and the opportunity for electricity storage

Both the eStorage and StRe@M project ultimately aim to explore if and how different RES shares impact the economic efficiency and value of energy storage technologies. This chapter therefore presents a background analysis of why an increasing share of renewables in an electricity system's generation mix could be an opportunity for energy storage technologies. The analysis in principal goes for any electricity industry, but Europe and Germany are often highlighted because of their role in the StRe@M project.

2.1. Increasing renewable generation

2.1.1. European energy system transformation

Over the last decade the European energy system has been undergoing fundamental transformations, largely led and coordinated by the European Union. The main objectives of the new regulations were about guaranteeing a reliable, affordable and sustainable future energy supply for the region and decreasing its eco footprint. Renewable energy is an essential part of this transformation as it can contribute to all these objectives. A decarbonized European energy mix will not be possible without significantly higher shares of renewable energy. In addition, renewable production will help the European Union to tackle its long-standing energy security challenges by reducing, in particular, its import dependency on fossil fuels (European Commission, 2015).

One of the most comprehensive energy regulations implemented in recent years was the 2009 Renewable Energy Directive, a broad-gauged European policy framework aimed at supporting the development and adoption of renewable energy sources in the European electricity system (European Commission, 2009). The directive is characterized by quantified targets, regulatory clarity and market based investment incentives compatible with state aid rules. It includes a legally binding 20% target for the share of total European energy produced from renewable sources, a 10% target for the share of energy used in the transport sector produced from renewable sources and binding individual national targets for energy produced from renewable sources in 2020. The directive has become one of the key drivers for the European led global investment in renewable technologies as European nations have formed their national energy strategies and policies accordingly (European

Commission, 2015). Figure 4 shows the RES deployment targets and estimates for European countries.

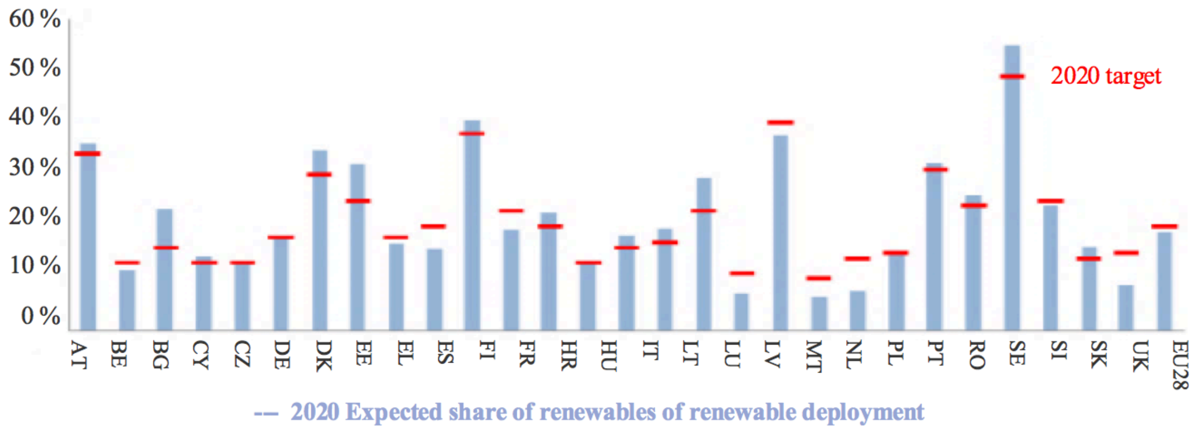

Figure 4 - Expected RES deployments and target levels for 2020 in which the numbers are based on policies implemented until December 2013 (European Commission, 2015).

2.1.2. Increasing wind and solar generation capacity

As a result of the efforts of the governments of the European countries to meet climate targets the renewable share of installed electricity generation capacity has increased significantly over the last fifteen years. Multiple generation technologies are considered renewable, of which hydro power generation, wind power generation and solar power generation are the largest when considering installed generation capacity. Other generation technologies considered renewable include those based on biomass, geothermal heat and waste. Figure 5 shows the generation capacity mix in Europe for the year 2000 and 2015. The two relatively largest increases in generation capacity are wind and solar. It must be noted that the differences in the installed generation capacity mixes between individual European countries are huge; in Germany over 39 GW of wind capacity is installed versus just over 9 GW in France whereas the consumption Is fairly comparable (EWEA, 2015).

Key enablers that impelled the increases of wind and solar generation are the facts that their resources, wind speed and solar radiation, are (1) widely available, contributing to reduced energy import dependence and increased security of supply and (2) come at zero cost, hedging it against fuel price volatility and stabilising generation costs in the long term (IEA, 2013). Furthermore, these generation technologies do not emit greenhouse emissions or other pollutants and do not consume water, which is an increasing concern in hot or dry regions (IEA, 2013). The main hurdle for wind energy's competitiveness with other technologies has been and will be its relative cost, though a downward trend in the levelized cost of energy (LCOE), the net present value of the cost per unit of electricity over the life time of the generating asset, is experienced (NREL, 2013).

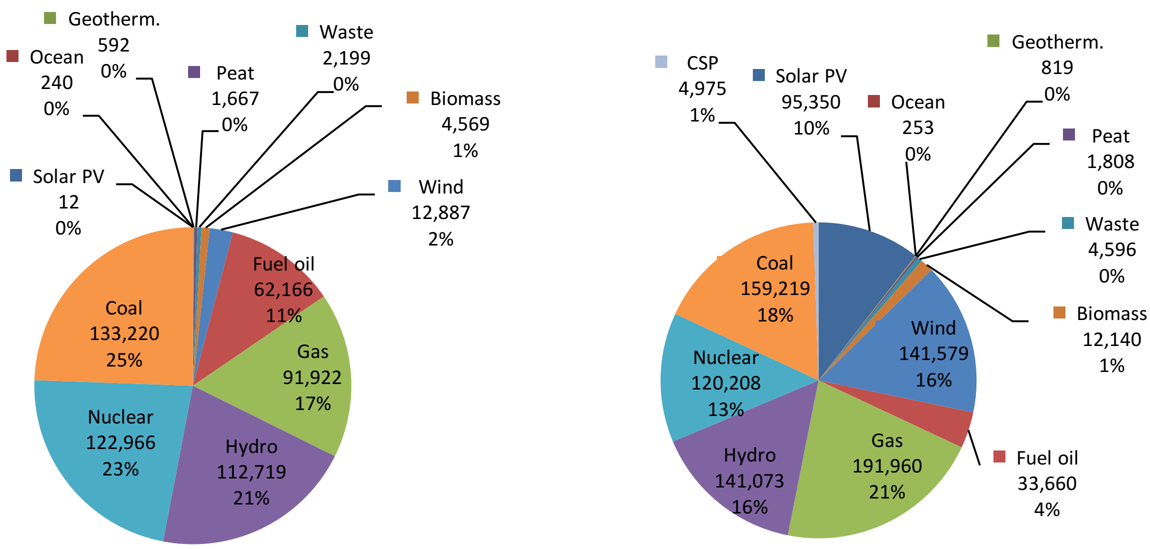

Figure 5 - EU generation capacity mixes in years 2000 and 2015 showing the incredible increasing in solar PV and wind generation capacity (EWEA, 2015).

Also in the future these enables are expected to continue to push the growth of renewable generation capacity. Many scenario studies have been conducted to map potential future states of European electricity grid to inform investors and policy makers of the potential opportunities and challenges this brings. One of the leading scenario studies on European energy was the 'Energy roadmap 2050' commissioned by the European Commission in 2011. The study analyses energy trends up to 2050 and acknowledges the important role of wind and solar generation (European Commission, 2011).

2.2. Intermittency of renewable energy sources

Most of the renewable electricity sources come with a peculiarity, namely an intermittent availability. Intermittent generation is any source of power that is not continuously available due to factors outside the operators' control. Both wind, hydro and solar power, the biggest renewable technologies integrated in the European grids, are intermittent by nature. They are subject to the availability of wind speed, rain fall and solar radiation respectively. Because the largest share of hydro power generation is from PSH plants, which makes use of a water reservoir for storage, their output effectively does become controllable. Also other renewable generation technologies are not intermittent by nature. Geothermal generation is not intermittent as the resource, the earth's sub crust temperature, is rather constant in any practical time scope considered for the electric power industry. And also power generation from biomass and waste is not intermittent, as this generation process and the resources are well controllable.

The impact of the intermittency of wind and solar generation output shows itself particularly in the short term, i.e. periods of hours or days, when the intermittency can cause high and rapid absolute output variations. Figure 6 shows the declining wind generation output over a day in Germany in 2015. Between 2 and 5 AM the onshore wind output decreased from 24.000 MW to 19.000 MW. This difference of 5 GW is equal to the (nameplate) capacity of three large nuclear plants. The total installed onshore wind capacity at this time was 41 GW.

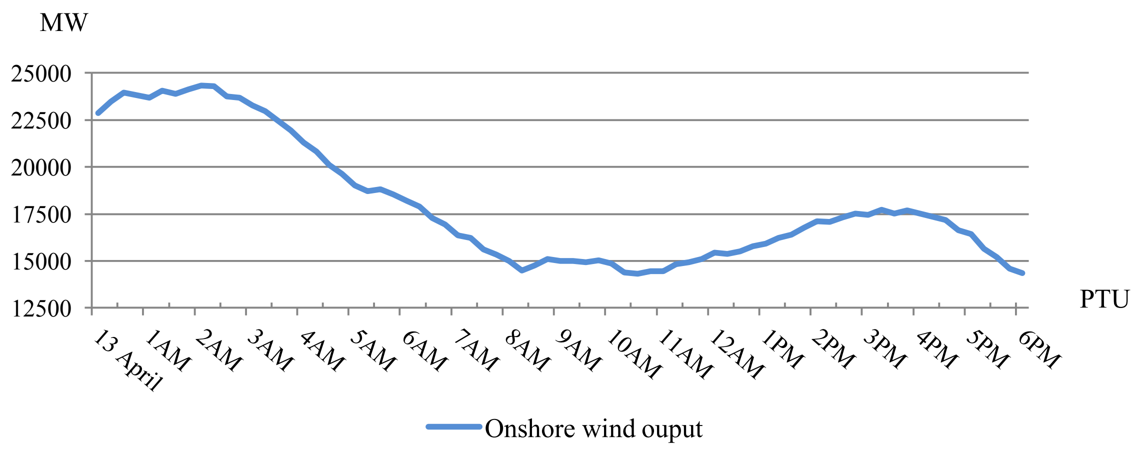

Figure 6 - Onshore wind generation output in German on April 13th, 2015 (ENTSO-E, 2016).

Contrary to unpredictability of wind and solar output in the short term, their long term productions, i.e. over a year or longer, are quite well predictable. Over these periods the time integrals of wind speed and solar radiation are fairly constant in most areas and hence so are wind and solar generation.

2.3. Intermittent renewable generation and grid flexibility

2.3.1. Impacts of increasing intermittent renewable generation on an electricity grid

The impacts of intermittent generation differ per electricity system and can be both desirable and undesirable. Many well-written papers are available extensively covering the whole range of impacts. Literature roughly categorizes the impacts as either economical or technical.

Economic impacts of increasing intermittent renewable generation include effects on unit dispatch (see Annex A), the schedules of each generator if to produce and how much and when, and electricity prices (Pérez-Arriaga and Batlle, 2012). Some studies, like Vos (2015), have concluded that the impact of renewable generation on electricity prices is significant, and support this with the negative energy prices experienced in multiple countries including Germany. The negative energy prices occur when abundant intermittent renewable generation output suddenly becomes available, and their low marginal cost thus places them early in the merit order (see Annex A). Other generators who were producing just before those moments are pushed out of the market on the base of cost of production. In some markets, like Germany, cost of production is even irrelevant because renewable generation enjoys grid priority, meaning they are allowed to meet demand first and only the residual load is left for conventional generation. Sometimes generators are willing to pay to keep producing and prevent shutting down and incurring start-up costs later. This can result in negative prices. Pérez-Arriaga and Batlle (2012) show that though low marginal cost intermittent generation replaces more expensive generation sources it is rarely replacing the generation technology setting the marginal price in most hours of the year. Hence, intermittent renewable generation reduces the overall supply costs (Morthorst and Awerbuch, 2009) but does not set the wholesale electricity price. The high subsidies that some countries have in place to encourage the adoption of renewable generation are putting an upward pressure on electricity prices though as these support mechanisms are generally paid for by extra taxes and levies on electricity (Ecofys and Fraunhofer, 2015). Other interesting studies analysing the price impact of intermittent renewable generation in Europe are Swinand and O'Mahoney (2015) for Ireland and Gulli and Balbo (2015) for Italy.

The technical impacts of intermittent generation on electricity systems include the impacts on grid infrastructure requirements. The variability in intermittent generation output will result in increased volatility of the current through the transmission lines connecting the plants to the grid, which can increase costs.

Presumably the biggest technical impact of intermittent generation is its impact on an electricity system's ancillary services though. Ancillary services are necessary to facilitate the secure and reliable transmission of electric power from seller to buyer and they include services to help maintain proper voltage and frequency levels, provide black start capabilities to help the electricity system to restart after blackouts and services to maintain the grid balance and ensure that the load taken from and the generation supply to the grid are always equal. Table 3 highlights some of technical limitations and impacts of wind and solar generation compared to conventional generation techniques, resulting from their lack or limitation of controllability.

Table 3 - Technical limitations of wind and solar generation. The limited controllability has an impact of several grid functions.

Product	Conventional generation	Wind generation	Solar generation	Impact grid function/service
Active power	Yes	Yes	Yes	Energy trading/commodity
Reactive power	Yes	Limited	No	Voltage control
Inertia	Yes	Limited	No	Balancing
Balancing	Yes	Limited	Limited	Frequency stability
Self-start capability	Limited	Yes	Yes	Black start capability

2.3.3. Grid balance and balancing power principles

As the impacts of intermittent generation on grid balance and ancillary services have a special role in later sections of this study it will be explained in more detail in the next subsection. This subsection will first briefly present the technical basics of grid balancing and balancing power needed to understand the impacts intermittent generation can have on it.

Maintaining supply and load in balance is important for safely providing electricity to consumers. In case of a grid imbalance the frequency will deviate from its intended value. If the deviation exceeds a certain threshold it can harm devices connected to the grid and eventually lead to a black out. In most electricity industries a regulated market or system operator is responsible for maintaining the grid balance, and oversees the electricity trading, I.e. the matching of sellers and buyers also referred to as market clearing (see Annex A). As electricity is always traded between years and about 15 minutes ahead of actual time of delivery, the market operator determines the quantity of energy to be cleared or sold ahead based on forecasted demand. When the trading is then stopped, usually 15 minutes before actual delivery, the sum of all generation schedules is set as close to the forecasted electricity demand at the time of delivery. It is the task of the system operator to make sure the grid balance is achieved in real-time though, even if expected demand or generation changes in the 15 minutes between the closing of the market and actual delivery. If there is no balance in real-time between supply and demand, there is an imbalance. Causes for imbalances can be plants experiencing outages or intermittent generation forecasts that proved to be inaccurate causing operators to not exactly produce as their obligatory schedules.

In case an imbalance occurs, it is the system operator's responsibility to make sure some reserve power is available that can be fed to the grid, or that can be turned down to compensate for the supply deficit or excess respectively. This reserve power is contracted for a certain period of time by the grid operator in an auction. When plant operators win such auctions, and get a reserve contract, they are agreeing to provide capacity for balancing power for a certain period of time. This implies that they have some generation capacity available that, whenever called upon by the system operator, can slightly increase (upward reserve) or decrease (downward reserve) its generation output. Providers generally receive a reimbursement for providing these reserve service and balancing energy to the grid.

Reserve power therefore has an option- or insurance-like character which is also mirrored by the two-part pricing resulting in a so-called multi-part auction. The first component is the required compensation by generation operators for providing reserve capacity during a specific time period. This reimbursement is not dependent on whether or not the provider is actually activated and called for to supply reserve energy. To determine this reserve capacity bid the providing generator takes into account that he cannot sell his capacity twice as any capacity promised to the reserve market cannot be used to trade on the spot electricity markets.
The second bid component is the required compensation for providing a certain volume of reserve energy when the provider is activated during the specific time period his reserve capacity is contracted. In a well-functioning market capacity prices should reflect opportunity costs such as foregone spot market profits while energy prices should mirror actual costs of generation (Hein and Goetz, 2013).

Though regulations differ per country the costs associated with balancing services are partially paid for through higher levies on electricity prices. The amount of balancing capacity required and activation thereof is determined and contracted by the system operator and depends on desired security levels.

2.3.4. Intermittent generation impacts on grid balance

Conventional generation is primarily used to supply active power to the grid, but because of its controllability this type of generation can also provide balancing power. Intermittent generation is limited in providing balancing power, as the operator can never guarantee that he can increase or decrease output when requested, as he does not control its resource and hence output. The only way to control intermittent generation is typically through curtailment which is basically turning off the generator. The fact that intermittent generation cannot provide balancing power is one thing. It is another, that intermittent generation, because of its very nature, actually requires additional amounts of balancing power and thereby increases costs associated with it and drive up cost for the consumer. This requirement for additional amounts of balancing power is due to two primary reasons.

The first is the relatively high uncertainty involved with intermittent generation output. As intermittency is a stochastic process it means that uncertainty is involved and it is unknown in advance when the output variations will occur. This non-controllable output variability implies a likelihood of intermittent generation being unavailable when generation is required that is significantly higher than for conventional plants (Pérez-Arriaga and Batlle, 2012). In case the system operator would know in advance when the generation deviations would occur he would have time to adjust the generation schedules of other market participants and allow the supply deficit to be traded on the electricity markets. When the production deviations occur unexpectedly in real-time though, balancing power has to be used for compensation as there is not enough time to trade this electricity within less than seconds on the electricity markets. Forecast models for predicting solar and wind generation output are getting more advanced and accurate each year. Still solar and wind production forecasting errors can vary from over 10% for a period of two days ahead of production to less than 2% for a period of one hour ahead of production (NREL, 2012). If the energy fed to the grid by wind and solar is large enough these small percentages can still amount to substantial generation deficits. As a result, the relatively large uncertainty involved with the intermittent generation output compared to conventional generation output results in a higher probability of system imbalances. This will require increase demand for balancing power which increases the overall costs of balancing services.

Also the speed or ramp rates of intermittent generation's output deviations can pose a threat for grid balance. Wind speed can almost complete drop to zero within an hour and solar radiation can be blocked even faster when a big cloud front passes by. To economically efficient compensate for the resulting deficits with large ramp rates also compensating capacity with large ramp rates needs to be available. This is valid both for when the output deviation is unexpected and the compensation will be provided by balancing power, as well as when the output deviation is forecasted accurately a few hours in advance and compensating supply is traded on the electricity markets. It is economically inefficient to have nuclear plants provide this compensating power, as nuclear generation has rather small ramp rates and takes days to start up. The most flexible large-scale generation technologies installed today are gas and hydro generation. But even if the balancing services would be provided by the fastest gas turbines, in light of the European energy transformation, grid operators are ideally not looking to encourage installing extra conventional gas turbines to contribute to grid flexibility. Providing balancing services with conventional generation running part-loaded will not only reduce efficiency of system operation but will significantly undermine the ability of the EU system to absorb intermittent renewable output as ramp rates are conventional generation ramp rates are still limited. Also this would increase emissions and all-in-all drive up cost for the consumer. A more efficient solution is thus to get balancing capacity provided from generation capacity with fairly high ramp rates, which tends to be more expensive in terms of production costs and thus will results in higher average reserve prices.

Besides higher likelihood of imbalances occurring the relative size also increases as intermittent generation output variations increase with the total intermittent capacity installed. The 5000 MW loss of German wind output highlighted in Figure 6 occurred with an installed wind capacity of 41 GW and will increase when additional wind capacity is installed. Figure 7 presents two generator dispatch scenarios, which shows that the different generation technologies, represented by different colours, have much higher output variability in a scenario with a high share of solar generation. The other generation technologies are 'forced' to adapt.

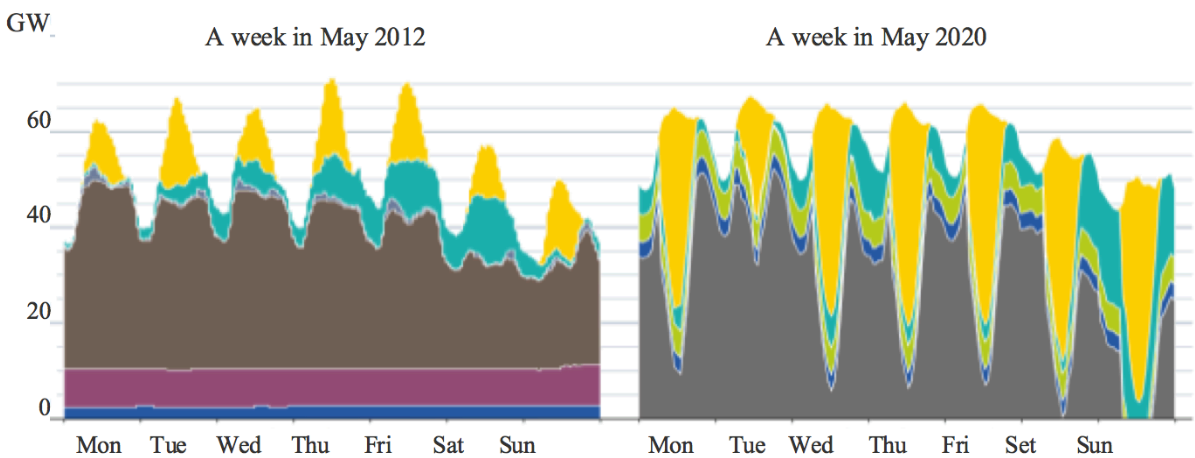

Figure 7 - A German generation dispatch schedule from May 2012 and a hypothetical schedule in 2020 (eStorage, 2014). Large quantities of cheap solar (yellow) generation force other generation technologies to rapid output variations.

2.3.5. Grid flexibility to facilitate adoption of intermittent generation

To be able to maintain the system balance in the European electricity system with the high output variability of intermittent generation output the demand for additional grid flexibility increases, including but not limited to additional and flexible balancing power.

Grid flexibility refers to the ability to respond to variations in generation or load, and although there is no single clear measure for grid flexibility, an example metric is the Insufficient Ramping Resource Expectation (IRRE). This metric assess to what extent (planned) capacity allows the system to respond to short-term variations in the load and it is the expected percentage of incidents in a time period when a power system cannot cope with changes in net load (NREL Flexibility, 2014). By most definitions grid flexibility in an electricity system is not just provided by a generation portfolio with high ramp rates though. Grid flexibility is determined by generation, load, grid infrastructure and market mechanisms. Because these factors differ per electricity system grid flexibility is highly system specific (NREL flexibility, 2014).

An electricity industry with generators with a relatively flexible generation fleet, i.e. having a high (average) ramp rate, will help the market cooping more easily with load variations in the different electricity markets. The likelihood that buyers and sellers can be matched in varying situations increases. Having a flexible generation fleet could result in more balancing market participants and improve flexibility there also. The load side of an electricity industry can also facilitate the grid balance through load shedding, disconnecting certain regions from power, or demand side management. The latter refers to providing load incentives to adjust their consumption. Load shedding, which is instigated by transmission operators, is only considered a last resort though. Grid infrastructure can be flexible by accommodating highly variable current flows resulting from e.g. sudden intermittent generation production changes. But even when adequate flexible generation and load shedding programs can be established, a quick activation of these countermeasures also needs to be possible. The power market needs to be designed in such a way that it is able to accommodate quick turn transactions and make full use of the flexibility of the transmission system and the different generation technologies to effectively respond to increased uncertainty (DIW Berlin, 2011).

2.3.6. Electricity storage to provide grid flexibility

Energy storage has the capability of increasing grid flexibility in multiple ways, from both the load and generation side, and thereby indirectly facilitates adoption of intermittent generation in an electricity grid. The way flexibility is provided depends on how it is implemented in an electricity grid. Energy storage is a special case of generation technology because actually no netted energy is created but it is capable of 'regulating' energy flows by functioning as a buffer.

As elucidated in the introduction electricity storage deployments can mitigate variability in electricity flows through transmission wires and mitigate congestion and help flatten demand and peak shaving.

When deployed near transmission or distribution lines the storage capability can be used to level out electricity flows to mitigate congestion and postpone required grid expansions. As the design of a transmission line is based on the maximum current that the line must be able to carry, and gets more expensive with higher currents, costs can be saved on grid expansion.

When energy storage is deployed near load, like when private consumers install it, it can help to flatten the demand. At times when electricity is cheap the storage capacity can consume energy for storage, only to use it later on when the energy is needed or return it to the grid when demand and prices are high and profit from the arbitrage. This process is illustrated in Figure 8.

Implementation near generation facilities allows operators to realize a stable and constant output by storing energy when it is abundantly available and deliver it to the grid when a supply deficit looms threatening delivery agreements. This is particularly interesting for operators for operators of intermittent renewable generation as it mitigates the risks associated with the uncontrollability of the output. Because of its high ramp rates energy storage is also particularly useful for balancing purposes as it meets the strict technical requirements.

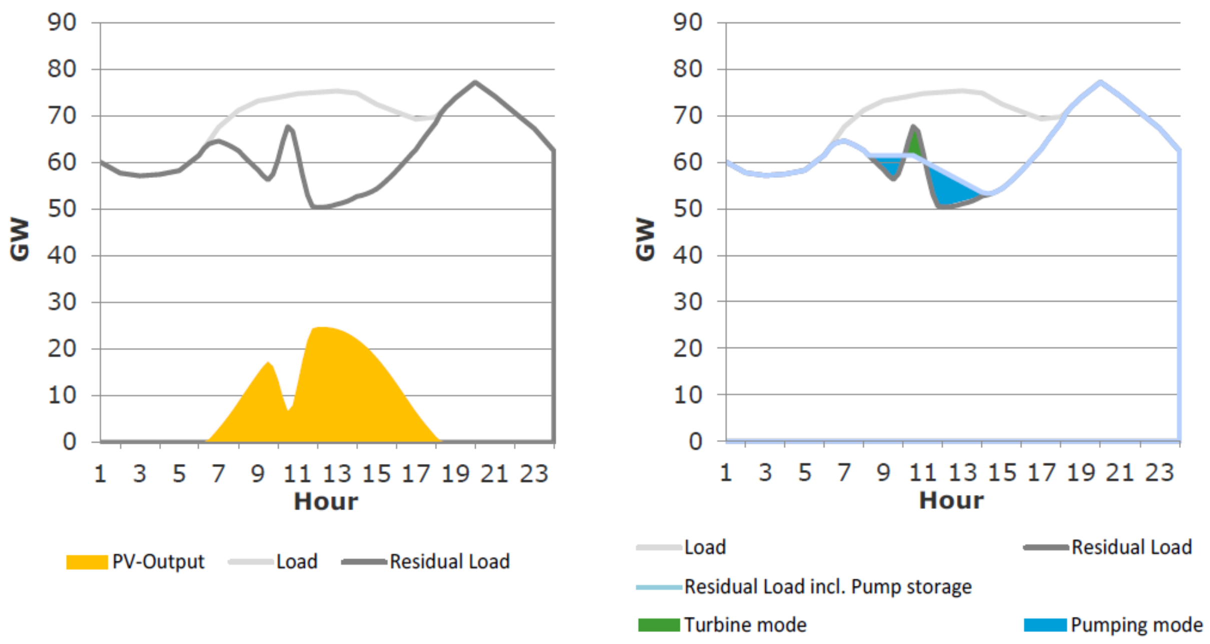

Figure 8 - Peak shaving and load levelling through storage of electricity (Eurelectric, 2015).

Chapter 3. Literature review

This chapter provides a literature review on the economic feasibility of electricity storage technologies and on the available models and used modelling principles to determine and assess the potential cost and revenue streams.

3.1. On the potential of grid-scale electricity storage technologies in future grids

A first overview of the available literature targeted the potential of grid-scale electricity storage technologies in future grids, and the relation with increasing shares of renewables. A selection of the most relevant studies and insights is provided.

Carnegie (2013) provides an introduction to grid-scale electricity storage and how it can solve the intermittency challenge of renewable generation. Only some battery technologies and PHS are identified as mature technologies suited for grid-scale deployment. The study provides a brief overview of storage costs and operational value but the conclusions are specific for the US electricity system. The section about vanadium redox flow batteries is specifically interesting as this electricity storage will likely also be modelled in the StRe@M project. The Institute of Mechanical Engineers (2014) provide a comprehensive analysis of the requirements for grid-scale electricity storage in the future UK electricity system if the country is to meet its future climate targets. An important recommendation they make is that governments must recognize that energy storage will not be incentivized appropriately with existing market mechanisms. The study furthermore provides an interesting comparison of different electricity storage technologies and their associated costs.

3.2. Assessment of the electricity storage market for renewables

By assessing plans from 26 different countries IRENA (2014) states in their renewable energy roadmap 2030 study that the total capacity of PSH will increase from 150 GW in 2014 to 325 GW in 2030. Later IRENA published a comprehensive complementary report on this energy storage roadmap in which they argue that electricity storage should be looked at, but should not be an end in itself (IRENA, 2015). This study also provides an interesting cost comparison between different electricity storage technologies. In 2009 IEA estimated a global electricity storage capacity of 180-305 GW which included PHS (IEA, 2009). The study assumes an annual intermittent renewable share of generation of around 30%. In an updated study they then adjusted these estimates to 460 GW of electricity storage and an annual intermittent renewable share of generation of 27% (IEA, 2014). Just recently CitiGroup (2015) determined an electricity storage market size of 240 GW by 2020 which excluded PHS and storage capabilities in cars. A German study by the Fraunhofer ISE research institute (2013) makes an estimation of the electricity storage capacity required to facilitate a German electricity industry that consists for 100% of renewables. The requirements are listed as 24 GWh of battery-storage, 60 GWh of PSH, 670 GWh of heat storage and 33 GW of electrolysers (hydrogen).

3.3. On the value of electricity storage technologies

There is abundant literature available on the system value of electricity storage technologies but much less on the assessment of the value from an investor's perspective, which is most relevant for the StRe@M project.

Byrna and Silva-Monroy (2012) estimate the value of an 8 MW storage facility in the Californian electricity system and show that 4 times more revenue can be made when operating the facility on the reserve market compared to using the facility for load-shifting. They estimate a storage value of \$117-\$161/kW/year, which is based on historical data for the electricity markets in 2009.

NREL (2013) defines the system value as the difference between an electricity system with and without different sizes of electricity storage capabilities and provides an interesting comparison between the two types. They show that the system value is generally higher than the investor value and that both decrease with a larger storage facility. The latter is because of the merit order design of the matching of bids and offer in electricity markets. For estimated values NREL analyses a virtual electricity grid and shows that more costs can be saved when the storage facility is used for ancillary services compared to when it is used for load-shifting. The most savings though can be obtained when the facility can operate on both the energy and ancillary service market and is estimated at 128\$ kW/year.

Strbac et al. (2012) estimate the value of electricity storage in a future low carbon UK electricity grid by optimizing the quantity of storage in a system. They underline that potential system savings are increase markedly with increasing renewable penetration. For a a scenario in 2020 with a wind capacity of 35 GW they estimate the value of a storage capacity of 2 GW of £105/KW/year yielding total system savings of £120M/year.

3.4. Revenue assessment studies and models

By modelling the potential cost and revenue streams the StRe@M tool will assess the economic feasibility of electricity storage alternatives from a price-taking investor's perspective. Despite its industry experience, DNV GL knows of no similar tool available in the industry that can be practically applied to forecast future revenues, let alone doing this from an investor's perspective.

There are many revenue forecasting tools available but they almost all analyse historical data to assess what revenues could have been obtained in the past. These models do not forecast future revenues, although some of the models are suited for present-day. With the ongoing transformation of the European electricity grid, it is unlikely that operating models and revenue assessments of the past will be a good proxy for the far future of 2020 onwards. The effects of a changing generation mix, including large amounts of intermittent generation, should somehow be taken into account by models looking at the future. It is exactly these forward-looking models that potential investors in energy storage are interested in today, and this is what StRe@M aims to deliver.

Table 4 provides an overview of a selection of energy storage value assessment tools available in the literature. The selection is based on relevance and on (a limited) assessment of the number of references to the studies. The main conclusions to be drawn are that no published models that assess future revenue streams could be identified. This is not completely unexpected as models that do forecast future revenues can have a commercial potential, meaning that they might not be publically available. The identified existing models mostly only considered one revenue stream from the spot market. The ones that did consider also an ancillary service market revenue stream almost all focused on the secondary reserve market.

Table 4 - Literature overview of energy storage value assessment models.

Paper title	Energy storage technology considered	Author(s)	Year	Model/method description	Markets modelled		Time horizon
					Day-ahead spot market	Ancillary services	
Economic viability of energy storage systems based on price arbitrage potential in real-time US electricity markets	Various	Bradury, Pratson, Patiño-Echeverri	2014	Assessment of the potential electricity arbitrage (DAM) revenues of 14 different energy storage technologies in several electricity markets in the United States in the year 2008. The impacts of technological characteristics (including hours of storage capacity) on the potential revenues are also assessed.	X		1 year
Optimal operation of variable speed pumped storage hydropower plants participating in secondary regulation reserve markets	VS-PHS	Chazarra, Pérez-Díaz, García-González	2014	A deterministic optimization model, designed for the Spanish electricity market, to find a maximum theoretical income that price-taking operators of VS-PHS operators could have obtained between 2012 and 2013. Based on past data, the model determines bids for the hourly day-ahead and upward and downward secondary regulation markets.	X	X	1 day/2 years
Potential arbitrage revenue of energy storage systems in PJM during 2014	Various	Salles, Aziz, Hogan	2014	Revenue assessment model for energy storage technologies (including flywheels, batteries and super capacitors) in the PJM market in the United States. The model used historical data (year 2014) from the PJM wholesale market to determine the potential arbitrage revenue that could have been obtained. Only the DAM was considered.	X		1 year
Market requirements for pumped storage profitability - Expected costs and modelled price arbitrage revenues	PHS	Salevid	2013	A Simulink model is presented to assess historical potential revenues for PHS operators. The analysis is based on historical spot market data between 2001 and 2012 in Sweden and Germany.	X		1 year

Prospects for pumped hydro storage in Germany	PHS	Steffen	2012	Analyses and modelling of the current developments around PHS and the revenue potential. Only the day-ahead spot market price arbitrage revenues are used in the model and revenues from ancillary service markets are labelled as upside potential.	X		1 year
Economics of centralized and decentralized compressed air energy storage for enhanced grid integration of wind power	CAES	Madlener, Latz	2011	Modelling of the economic feasibility of CAES using a profit-maximizing algorithm. The tool uses data on the feed-in of wind power and spot market and minute reserve prices in Germany for the year 2007. The authors acknowledge that for regions with different market or wind conditions the validity of the results is limited and that effects of a rising share of renewables are not taken into account but would affect the results.	X	X	1 year
The value of a pumping-hydro generator in a system with Increasing Integration of wind power	PHS	Pinto, de Sousa, Neves	2011	A model to identify the optimal bidding strategies for a PHS operator in the Iberian electricity market. The model is implemented in GAMS and considers the day-ahead and the ancillary services markets. The model assumes a linear relation between the day-ahead forecasted wind production and the required secondary reserve capacity.	X	X	1 year
Practical operation strategies for pumped hydro electric energy storage (PHES) utilising electricity price arbitrage	PHS	Connolly, Lund, Finn, Mathiesen, Leahy	2011	Four different operation strategies to maximize theoretical operational income of energy storage facilities in liberalized markets are compared. The strategies make use of the given hourly-prices and analysed, in hindsight, the period 2005-09. Only arbitrage is considered.	X		1 year
Bidding strategy for pumped-storage plant in pool-based electricity market	PHS	Kanakasabapathy, Shanti Swarup	2009	A tool that allows a pumped-hydro-storage plant to optimally determine the short-term self-scheduling in the day-ahead energy and ancillary services market in a competitive electricity market. The model uses forecasted electricity prices, but considers these a given input from other models.	x	x	1 year

Chapter 4. Research scope and objective

This chapter presents the scope of this thesis research and presents the research objective and questions. The time scope of this research is fixed and limited to approximately five months.

4.1. Research objective and deliverables

As stated in the Section 1.5 this thesis study is part of the initial modelling phase of the StRe@M project. The main research objective is to provide insights in the economic feasibility and opportunities for electricity storage technologies in an electricity industry. A qualitative foundation for part of the modelling approach and methodology of the StRe@M project will be formulated and the first modelling runs will be completed for an initial StRe@M prototype.

The deliverables will be this thesis report and multiple proprietary MS Excel (VBA) models.

4.2. Research scope

4.2.1. Geographical scope

As the economic feasibility of any electricity storage technology will be country specific a tool like StRe@M will also be; different market structures and regulations of electricity systems might require different modelling approaches for future ancillary service revenue streams. The geographical scope of this thesis study is limited to the German electric power industry, effectively using the country as a case study. Germany is chosen because of its high share of renewable generation and because fairly high-quality data was expected to be available. Because Germany is also part of the eStorage project, introduced in Chapter 1, the results of this study can be used for DNV GL's eStorage deliverables also. Despite the focus on Germany, some of the analyses might have to be extended to other European countries in order to extract useful results and insights from the analyses and validate assumptions and findings.

4.2.2. Modelling scope

A preliminary modelling structure was formulated by DNV GL during the formation of the StRe@M project. This structure was broken down in four modules and formed the starting point for the modelling in this thesis study. The modelling scope of this thesis study is limited to two of the four modules; the Imbalance Forecaster module and the Cost and Revenue module. They are depicted as modules B and D in Figure 9 respectively. In parallel and in collaboration colleagues at DNV GL developed the dispatch and spot price calculator and the capacity allocation scheduler, labelled as modules A and C respectively.

Upon successful completion of all four modules this study combines the four modules and will present the first StRe@M results and reflect on its implications, possibilities and limitations.

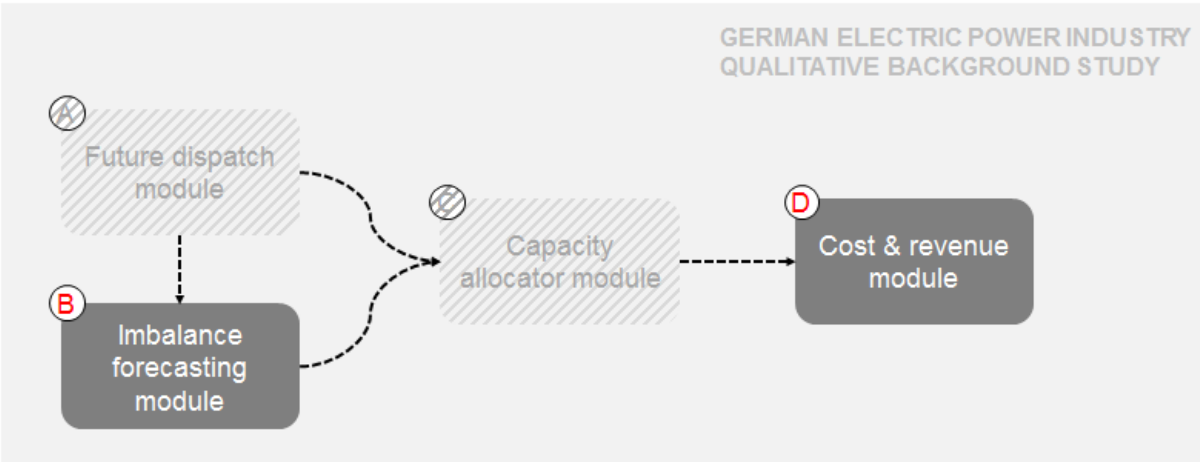

Figure 9 - StRe@M modelling decomposition. The model evaluates two revenue streams, one from the spot market, which is evaluated by Module A, and one from the reserve market, which is evaluated by Module B.

4.3. Research questions

The main research question of this study, formulated along with the StRe@M project's objective, was formulated as

> *What is the economic feasibility of electricity storage technologies in future scenarios for the German electricity grid from a price-taking investor's perspective?*

The main research question will be answered by both a quantitative modelling analysis as a qualitative regulatory analysis. The future scenarios are not specified in more detail (e.g. with a year or a RES share) because this will depend on the progress, findings and results of the modelling of modules A and C, largely performed by DNV GL colleagues and outside the scope of this thesis research.

In addition to the main research questions the following sub research questions are formulated.

- *How does the regulatory framework in Germany define electricity storage and what are the implications on levies and support mechanisms?*

This research question relates to the regulatory study of the German electric power industry and the role electricity storage has in it. An answer to this question would try to specify the definition and position of electricity storage in German electricity regulations and touch upon important regulatory obligations or impositions which might include levies, taxes and support mechanisms.

- *What are the reserve market opportunities for electricity storage technologies in the German electricity market today?*

This question can be answered from the qualitative study of the German electric power industry and its legislations and laws. An answer would specify the reserve markets in which energy storage is allowed to be active, namely where the technical characteristics of the electricity storage technologies and regulations allow it to participate.

- *What are the main drivers that currently determine imbalance volumes in the German grid?*

Module B will assess revenues from the ancillary service market, of which balancing power will most likely have most potential. In order to forecast future balancing market revenues, the imbalance volumes and prices of the German electricity grid need to be forecasted as accurately as possible. A methodology should be developed to do this, as it is beyond the scope of this project to model the entire electric market and its dynamics.

Chapter 5. Methodology

This chapter presents the methodology applied for this thesis research. First, a complete picture of the preliminary methodology for the StRe@M tool is presented to show how the four modules interact. Then the methodology for the qualitative background study of the German electricity industry with its markets and regulations is presented. Lastly the methodology for the quantitative analysis of forecasting potential reserve market revenues, module B, will be elucidated and also the methodology for the Cost and Revenue module is presented.

5.1. Preliminary StRe@M methodology

The modelling scope of this thesis study is limited to two of the four modules of StRe@M, as elucidated in Section 4.1, but an overview of the preliminary methodology for the modelling structure of the whole tool in presented to first visualize the interconnections between modules. The initial modelling structure of the StRe@M tool was formulated at the end of 2015 and is composed of four modules, elucidated below and showed in Figure 10.

Module A: Future Dispatch

For the eStorage project, of which StRe@M is a spin-off project, future electric power system states of several of Europe's national electricity systems, including Germany, have been modelled for several years (eStorage, 2015). The scenarios incorporate different generation mixes, with varying share of RES between 40% and 100%. This scenario study was available to DNV GL for the StRe@M project and this thesis study. All annual scenarios use, as an assumption, the same forecasted load profile. The future dispatch module determines a future dispatch for these scenarios using an optimization algorithm coded in PLEXOS, an energy market modelling software with which with DNV GL has much experience. The future (deterministic) generation dispatches generally have a time horizon of a whole year, a 15-minute resolution and provide accompanying spot prices. The dispatch and spot prices can be used in the other StRe@M modules to assess the potential revenue from the spot and reserve market.

Module B: Imbalance Forecaster

The potential revenue from the reserve market depends on future volumes and prices of reserve services. This module forecasts future system imbalances and demand for reserve services with accompanying prices. The resulting future imbalance and reserve volumes and prices can be used in other modules to assess the potential revenue from the reserve market.

Module C: Capacity Allocator

Module C compares the potential revenues from the spot and reserve market and determines the optimal operation of the energy storage that would result in the maximum expected profit. The module thus determines when and how much capacity has to be used on the spot market and on the reserve market, given that participating in one market would exclude one from participating in the other market at the same time.

Module D: Cost and Revenue

This module incorporates cost and risk behaviour and determines the results from the revenue streams and presents the profit forecasts.

5.2. Qualitative background study of the German electric power industry

The qualitative study to explore the opportunities and challenges that electricity storage facilities might face in the German grid used available literature and German electric power industry regulations and laws. The German electric power industry regulatory framework was described and analysed and implications for ownerships restrictions, market participation and other relevant aspects were investigated. In addition, the DNV GL's network was used when needed to find colleagues or parties with specific knowledge to verify findings or fill knowledge gaps. The result of the qualitative study is an assessment of how electricity storage assets can be deployed by private investors, and what the most relevant restrictions are.

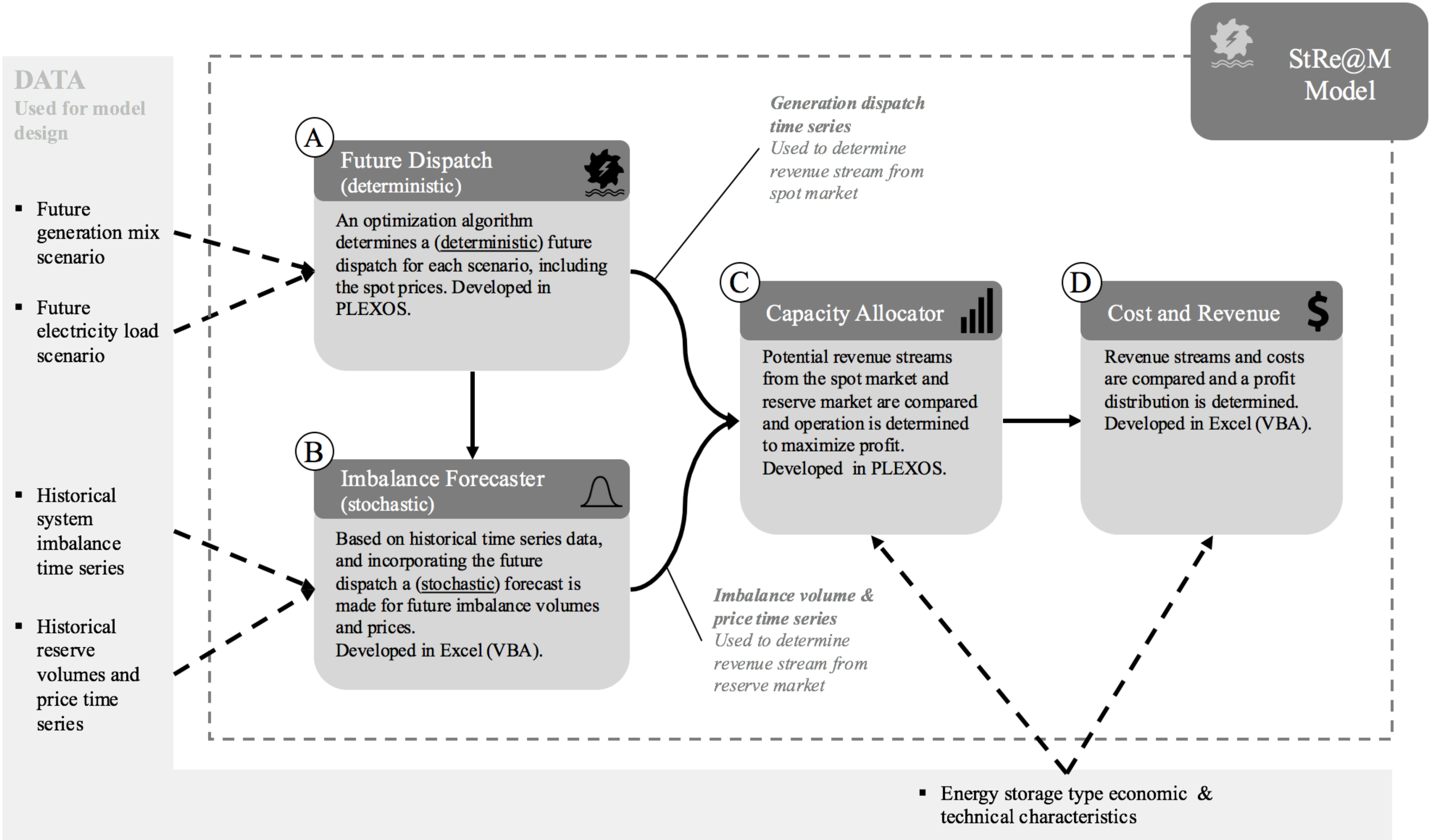

Figure 10 - StRe@M modelling structure. The modelling scope of this study is limited to modules B and D.

5.3. Imbalance Forecaster module and analysis

5.3.1. Initial bottom-up approach

The function of the Imbalance Forecast module was to analyse potential revenues from the reserve market. The first step in the methodology was to identify the reserve revenue stream with the biggest potential as it was expected to be out of the (time) scope of this thesis study to model multiple streams. The identification of the revenue stream to model was based on:

- Literature study
- Market size
- Number of participating agents

The outcome of this analysis was the secondary reserve market. The methodology to get to future secondary reserve demand is presented in Figure 11 and will be elucidated through four steps.

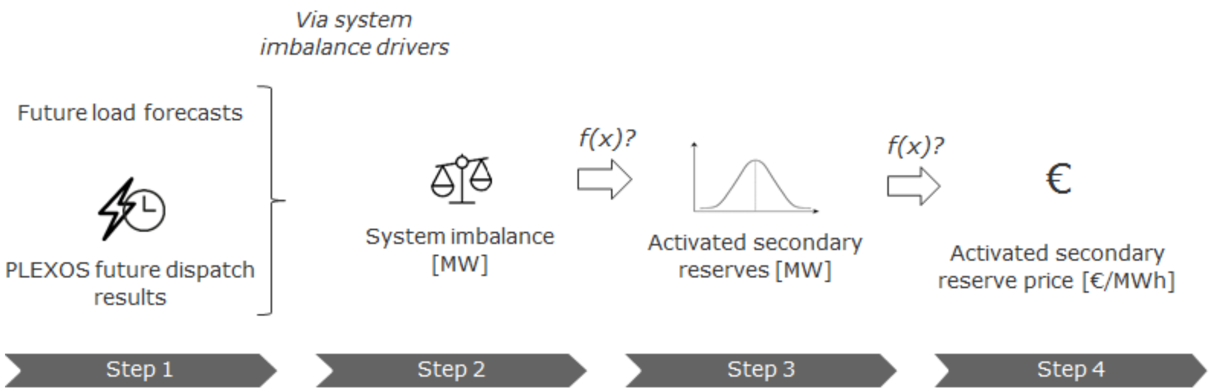

Figure 11 - Initial methodology for the Imbalance Forecaster module.

Step 1-2 (bottom-up approach)

After the secondary market to be modelled was identified, which was the secondary reserve market, the Imbalance Forecaster module was to forecast future system imbalance volumes, as they ultimately drive the demand for secondary reserve by definition (reserve are activated to mitigate system imbalances, as explained in Section 2.4).

The methodology used to forecast future system imbalances was initially based on a bottom-up approach. To see how system imbalances are formed in the German grid a literature review was performed to find a starting point for the modelling and identify, if any, main system imbalance drivers. It was expected that system imbalance drivers could be found within the installed generation mix and load profile (which are specified for each to-be-modelled scenario) of a system, or could be deducted from the generation dispatch and spot prices, which are available as inputs for the Imbalance Forecaster module and are provided by the analysis performed in the Future Dispatch module. When system imbalance drivers were identified the methodology was aimed at translating this relation between system imbalance and its drivers into a quantitative function.

Step 2-3

To move from system imbalance to secondary reserve demand a relation between the system imbalance and activated secondary reserves would have to be determined. Through analysing historical time series data of the two relations were explored. As the purpose of the activation of secondary reserves is to mitigate the system imbalance a positive relation was expected to exist between the two. Again, this relation would have to be translated in an approximate quantitative function suited for the StRe@M tool.

Step 3-4

To forecast future secondary reserve prices a relation was sought between the volume of the price of activated secondary reserves by analysing historical data between 2012-15.

5.3.2. Alternative top-down approach

The bottom-up approach suggested in step 1-2 in Figure 11 did not yield a workable result unfortunately. For the historical data no quantifiable relations between system imbalances and the system imbalance drivers could be identified. An alternative top-down approach was designed, which basically skipped steps 1 and 2 in Figure 11.

Step 1-4 (alternative top-down approach)

The top-down approach used historical time series of activated secondary reserves directly to forecast future secondary reserve demand. The historical distributions of activated secondary reserves were analysed between 2012-15 and were used as a basis to forecast future demand. The analysis then proceeded with an effort to identify a scaling trend in the distributions between 2012-15 depending on renewable penetration, as a relation might expected between the two because of the analysis presented in Chapter 2. This scaling trend could then be extrapolated to future scenarios based on their expected renewable penetration. In addition, an autoregression component in historical time series was identified. A stochastic function was then determined which retained the historical stochastic properties and data relations as accurately as possible, to use for the forecasting of future secondary reserve demand.

The activated secondary reserve prices were determined by performing a regression with historical time series between 2012-15 with the activated reserve price as dependent variable and the activated secondary reserve volume and spot price as independent variables. The values of the regression function were compared to the actual values, which resulted in a time series of residuals (the difference between the result of the regression function and the historical value). A distribution was fitted over these residuals to determine a random component to be added to the identified regression function in order to extrapolate the historical volume-price relationship.

5.4. Cost and Revenue module and analysis

The relevant costs of constructing, operating and maintaining an energy storage facility were identified through a literature review and from DNV GL's network of industry experts. A net present value and annuity analysis were used to determine a probability distribution for the value of a specific electricity storage facility. The investment module was programmed in Excel (VBA) and allows several risk profiles to be incorporated.

Chapter 6. German electric power industry and markets overview

This chapter provides an overview of the German electric power industry including the key industry figures, regulatory framework and relevant electricity and ancillary service markets. This information will provide a foundation for the analysis of the impact of German regulations on electricity storage deployment and reserve market analysis and forecasting in subsequent sections.

6.1. German electric power industry structure

6.1.1. Key industry figures

The German electric power system is the largest in Europe, providing electrical energy to over 80 million people domestically and, being a net exporter, millions of people in other countries throughout Europe (Agora, 2015). Electricity trading is done on a wholesale market and via (private) bilateral contracts. The industry is furthermore characterized by four dominating players on the generation, transmission and distribution levels. Over the last decades all industry levels have gone through substantial changes because of new and modified legislations and laws aiming to improve competition. Two of the most influential pieces of legislation have been and are the Energy Industry Act (*Energiewirtschaftsgesetz,* or EnWG), which since 2005 has slowly dismantled the vertically-integrated industry by unbundling its different levels and promotes efficient and reliable grid operation (Uwer and Zimmer, 2014), and the Renewable Energy Sources Act (*Erneuerbare Energien Gesetz*, or EEG), which promotes renewable electricity generation. Table 5 presents key figures for Germany and its electric power industry.

6.1.2. Generation level

Until the late 1990s the German electricity industry was characterized by a few vertically-integrated companies covering all industry levels and benefitting from regional monopolies. Since then the industry was gradually liberalized. Following the 2005 changes in the **EEG** generation and transmission levels were required to comply with legal, operational and informational unbundling rules, as well as unbundling of internal accounts (Uwer and Zimmer, 2014). The industry´s liberalization allowed many new generating companies to enter the electricity market and currently there are currently over 1.000 generating companies participating. Nonetheless, the industry remains dominated by four main players as has it been over the last decade. E.ON, RWE, EnBW and

Vattenfall, the 'Big Four', together produced over 50% of Germany's electricity generation in 2014. Their market shares are decreasing though, being 65% in 2013 and 79% in 2008 (Uwer and Zimmer, 2014). Table 6 presents an overview of the four dominating generation companies in Germany.

Table 5 - Key demographic and electric power industry figures for Germany (Agora, 2015; World Bank Group).

Demographics	Total population	82.5M (2015)
	Population density [/km^2]	23.1
	Urbanization [%]	73.9 (2011)
	Gross domestic product [$]	3868B (2014)
Electric power industry	Gross electricity consumption [TWh]	573 (2014]
	Average household electricity consumption [kWh/y]	3369 (2011)
	Peak demand [GW]	83.1 (2013)
	Installed capacity [GW]	192 (7/2014)

Table 6 - Dominant electricity generation companies operating in Germany in 2015 (Agora 2015).

Company	Description	Origin	Operating area	Installed capacity
EnBW	Full name Energie Baden-Württemberg AG.	Germany	Germany	56% market share (6/2014)
E.ON	One of the world's largest investor-owned utility companies.	Germany	Europe, United States	
RWE	Full name Rheinisch-Westfälisches Elektrizitätswerk AG.	Germany	Globally, but mainly Europe	
Vattenfall	Fully owned by the Swedish government.	Sweden	Europe	

6.1.3. Transmission level

A revision of the EEG in 2011 provided strict unbundling regulations for the transmission system operators (TSOs). Three unbundling models were formulated; full ownership unbundling or fulfilling the sole role of Independent System Operator (ISO) or Independent Transmission Operator (ITO). All are aimed to improve non-discriminatory access to the grid. The regulation caused the four large generation companies, who at that time also were the biggest owners of transmission assets, to unbundle their transmission activities from their generation activities. RWE, E.ON and Vattenfall subsequently chose to sell their transmission activities (full ownership unbundling) and EnBW continued as an ITO. Germany has since been divided into four balancing zones, each served by a different TSOs: Amprion (formerly RWE), Transportnetze (formally EnBW), TenneT TSO (formerly E.ON), and 50Hertz Transmission (formerly Vattenfall). Together, these four TSOs form the German interconnected electricity system (*Verbundnetz*). Table 7 presents an overview of the four TSOs in Germany and Figure 12 shows their geographical coverage.

Table 7 - German transmission system operators (Agora, 2015).

<table>
<tr><th>Company</th><th>Description</th><th>Operating area</th><th colspan="2">Installed HV lines in Germany [km]</th></tr>
<tr><td>Amprion</td><td>RWE formerly owned a 74.9 % stake of Amprion, of which most was sold to Commerz Real AG.</td><td>Germany</td><td>11.000 (2015)</td><td rowspan="4">100 % market share</td></tr>
<tr><td>TransnetBW</td><td>Unbundled from EnBW, but still remains under ownership of the EnBW Group (due to a specific unbundling structure). TransnetBW was formerly named Transportnetze AG.</td><td>Germany</td><td>3.475 (2014)</td></tr>
<tr><td>TenneT TSO</td><td>Formerly owned by E.ON, but fully owned by the Dutch government since 2010. TenneT is Europe’s only cross-border TSO.</td><td>Germany and the Netherlands</td><td>10.882 (2014)</td></tr>
<tr><td>50Hertz Transmission</td><td>Formerly owned by Vattenfall, currently owned by ELIA Group.</td><td>Germany</td><td>10.000 (2014)</td></tr>
</table>

Figure 12 - German balancing zones and the respective responsible transmission system operators as per 2015 (Agora, 2015).

Compared to other European countries German is quite interconnected (Agora, 2015). In 2012 the country had 21 GW of interconnection capacity to other countries. This is quite a high number compared to the country's 83 GW peak demand, and is due to the country's central location in Europe, making it a hub for power flows.

61.4. Distribution and retail level

Germany's distribution system is currently comprised of over 900 distribution system operators (DSOs), serving over 20.000 municipalities. The 2005 EEG forced the larger distribution companies (serving over 100.000 customers) to completely legally unbundle before 2007 (Agora, 2015). The four companies that dominated the generation level are also the four largest DSOs, but their combined market share remains unclear (Agora, 2015). For a significant portion of their activities these companies operate on concession contracts with municipalities; municipalities renting out their distribution franchise for periods of up to 20 years. Besides the four main DSOs, Germany has 700 utilities owned by municipalities, also called *Stadtwerke*, of which most are fairly small and supply fewer than 30.000 customers (Agora, 2015).

Though competition was introduced on the retail level in 1998, activity has been low and consumers show a high degree of 'stickiness'. In 2012 only 20% of household customers had switched from their default suppliers (Agora, 2015). Also on the retail level the market is dominated by E.ON, EnBW, RWE and Vattenfall with a combined market share of electricity offtake of over 45%.

6.1.5. Market operators

Most of the electricity trading in Germany is done via (private) bilateral contracts. As an alternative to these contracts buyers and sellers can meet on multiple big power exchanges covering Germany, including the European Energy Exchange or EEX in Leipzig, the European Power Exchange or EPEX SPOT in Paris and the Energy Exchange Austria or EXAA in Vienna. The various electricity markets offered by these market platforms will be explained in detail in future sections.

6.2. Regulatory structure

6.2.1. Regulatory authorities

German electricity regulation is developed and implemented on both a regional and national level. On a national level, and within the government, the responsibility for energy policy is divided between two ministries (Agora, 2015):

- Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (*Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit*, or BMUB).

- Federal Ministry of Economic Affairs and Energy (*Bundesministerium für Wirtschaft und Energie*, or BMWi)

Since 2014 most of the regulatory power is concentrated at the BMWi, with the exception of nuclear safety and environmental regulations. Falling under the BMWi, two other relevant national regulatory authorities are:

- Federal Network Agency (*Bundesnetzagentur*, or BNetzA)
- Federal cartel office (*Bundeskartellamt*, or BKArtA)

The BNetzA oversees various network industries, including electricity, gas, telecom and railway. Its responsibilities include ensuring non-discriminatory grid access, expansion of the grid, controlling grid access tariffs and controlling anti-competitive practices by the TSOs and DSOs and unbundling regulation of the industry (Uwer and Zimmer, 2014).

The BKArtA ensures market competition by controlling market abuse practices especially resulting from market power, which is very relevant because of the market dominance of the four big companies, and is responsible for merger control (Uwer and Zimmer, 2014).

Furthermore, there are two dedicated authorities to ensure market transparency and regulate and facilitate the emission trading scheme:

- Market Transparency Authority for Electricity and Gas (*Markttransparenzstelle Strom und Gas*, or MTS)
- German Emission Trading Authority (*Deutsche Emissionshandelstelle*, or DEHSt)

On a regional level, Germany is built up from 16 states (*Bundesländer*). From those states, 11 have state regulatory authorities (*Landesregulierungsbehörde*). The other states have transferred these authorities to the national level (Agora, 2015). The state regulatory authorities are responsible for the regulation of DSOs serving fewer than 100.000 customers and whose grids do not extend beyond the respective state's borders (Uwer and Zimmer, 2014). Together with state regulatory authorities the BNetzA also regulates revenues of (some of the) actors in the electric power industry.

6.2.2. Regulatory framework

During recent years energy policies have been an important topic on the German political agenda. One of the most influential developments in the Germen electric power industry today is the so-called Energy Transition (*Energiewende* – the term also used in English literature). The term represents and advocates a significant reorientation of the German energy policies, shifting from demand to supply and from centralized to distributed generation. Though first thoughts and versions of the Energiewende date years back legislative support was only passed in 2011. As the abandoning of nuclear energy is an important topic of the Energiewende it was the Fukushima disaster in Japan that opened the window to get enough legal support on the required levels. Though the targets and objectives have been broadly accepted in the country, the practical ways of achieving them remain heavily debated (Lehmann, 2015).

The main aspects of the Energiewende are (Uwer and Zimmer, 2014):

- Call for reform of the EEG to meet decarbonisation goals. Changes were implemented in August 2014 and included the abolishment of feed-in-tariffs (FiTs) and the introduction of a mandatory direct marketing scheme (including a market premium) for new renewable energy generators as well as a nuclear phase-out (*Atomausstieg*) to be finished by 2022 (Uwer and Zimmer, 2014).
- Lack of rules facilitating the successful expansion of the German offshore grid. In December 2012 changes were made to the EnWG to provide clearer guidelines for potential investors.
- Expansion of the electricity network to facilitate and integrate renewable electricity generation. With the installation of additional wind power, most likely in the Northern region where the efficiency is higher, the current North-South transmission congestion is only expected to get worse. Timely investments are needed in the transmission grid.
- Instigating the debate about Germany's current energy-only market versus a potential capacity market to maintain future security of supply.

Table 8 shows a selection of the relevant quantified goals of the Energiewende.

Table 8 - German Energiewende energy targets per 2016 (Agora, 2015).

All values are percentages [%]	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Greenhouse gas (GHG) emission reductions (compared to 1990-level)	40		55		70	80-95
RES share increase in gross electricity consumption (compared to 2008-level)		40-45		55-60		> 80
Primary energy consumption reduction (compared to 2008-level)	20					50
Gross electricity consumption reduction	10					25

6.3. Electricity consumption and production

6.3.1. Electricity consumption

Germany had the highest electricity consumption in Europe in both 2014 and 2015. Figure 13 shows a decreasing peak demand through recent years though, which was due to both a decrease in industrial activities following the financial crisis and energy efficiency measures. Future electricity consumption is subjected to many uncertainties like energy efficiency gains and technical, economic and social developments, but is generally expected to increase further until at least 2025 (ENTSO-E, 2015).

Table 9 - German electricity consumption comparison to Europe in 2014 (ENTSO-E, 2015).

	Germany	Spain	Netherlands	Europe (EU28)
Electricity consumption [TWh]	576	243	117	2,932
Peak demand [GW]	83.1	40.0	20	-

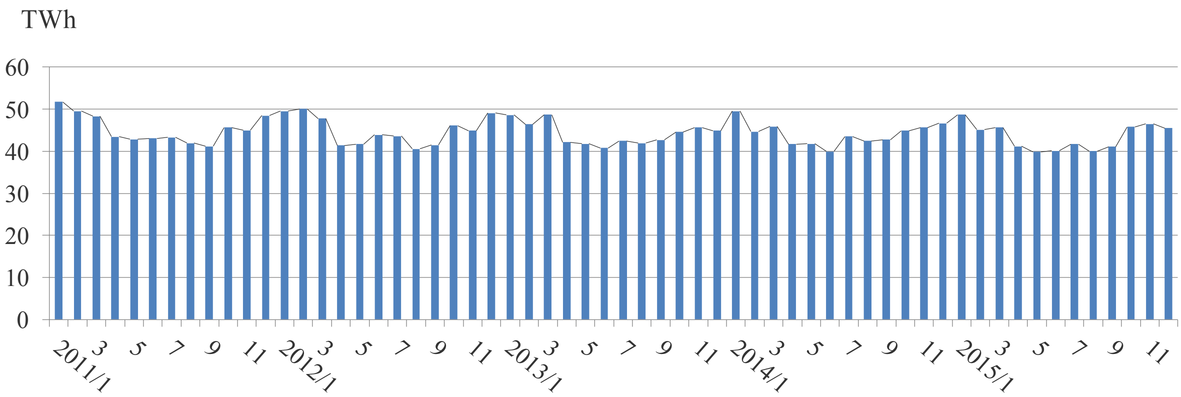

Figure 13 - German monthly electricity consumption for the period 2011-15 (ENTSO-E, 2015)..

6.3.2. Electricity production

German electricity production by source for the years 2011 to 2015 is shown in Figure 14. Since long the industry has been relying on both nuclear and coal for the production of electricity. The figure does show an increasing trend in both wind and solar production through recent years, as it is seen in many European countries. In Germany renewables accounted for over a quarter of electricity production in 2014 and even 31% in 2015 (Agora, 2015).

Table 10 - German electricity production comparison to Europe in 2014 (ENTSO-E, 2015).

	Germany	Spain	Netherlands	Europe (EU28)
Gross electricity production [TWh]	610	254	103	3013
Renewable production [TWh] (% of total production)	157 (25.8)	109 (42.8)	7 (6.4)	848 (28.1)

Figure 15 highlights the increasing trend of wind and solar generation, a result of the efforts to meet the climate and renewable goals. Also in the years to come this trend is expected to continue. Increased cost competitiveness of renewable technologies and continued government support are expected to be the main drivers (IEA, 2013). Without amendments to current legislations nuclear production is expected to be zero after 2022, when the closure of all nuclear plants is scheduled to be finalized. Depending on the developments in technologies to store polluting emissions, coal is also expected to gradually lose production share because of its environmental footprint.

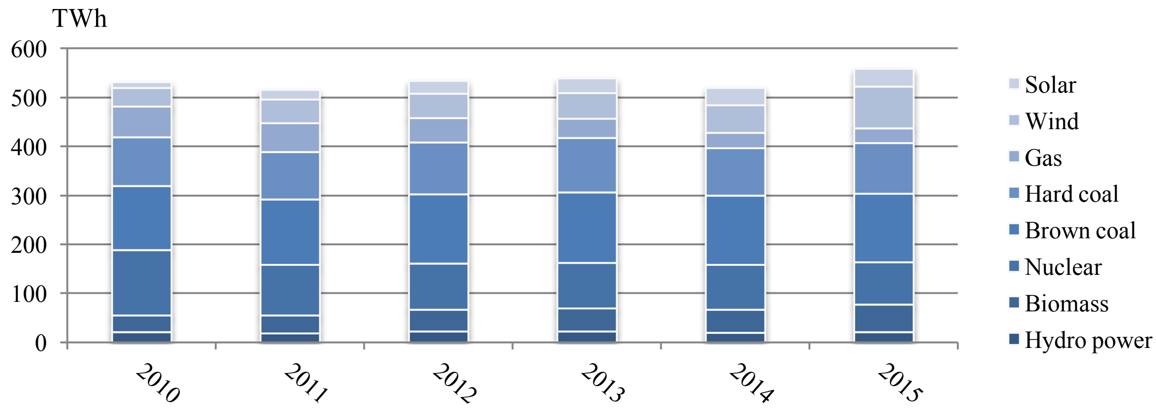

Figure 14 - German annual electricity production by source between 2010-15 (Fraunhofer ISE, 2015).

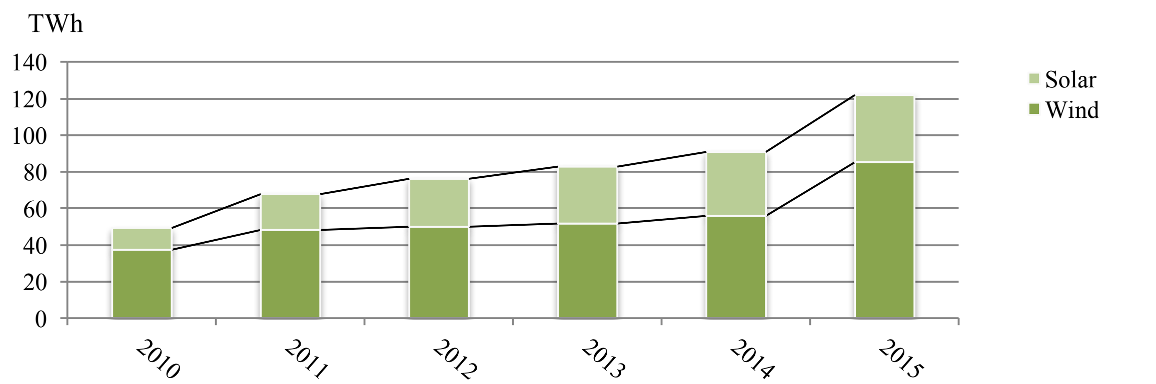

Figure 15 - Annual solar and wind generation in Germany between 2010-15 (Fraunhofer ISE, 2015).

6.3.3 Installed generation capacity

Figure 16 shows the installed generation capacity of various technologies in Germany over recent years. In 2014, over 41% of installed capacity used renewable resources, whereas nuclear and coal comprised a bit over 30% of installed generation capacity resource. Figure 17 highlights the significant increase of wind (both onshore and offshore) and solar generation capacity, which underlay the increasing share of energy produced from wind and solar power.

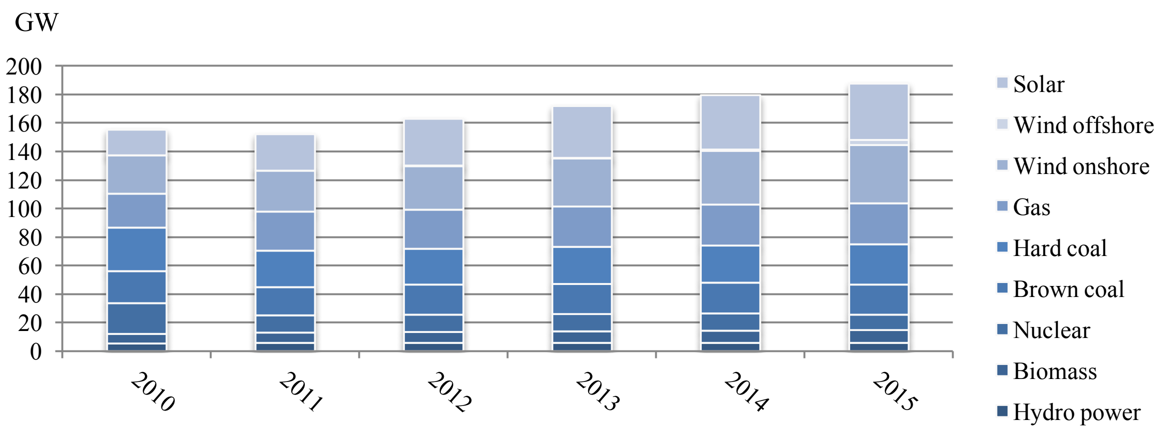

Figure 16 - German installed electricity generation capacity by source between 2010-15 (Fraunhofer ISE, 2015).

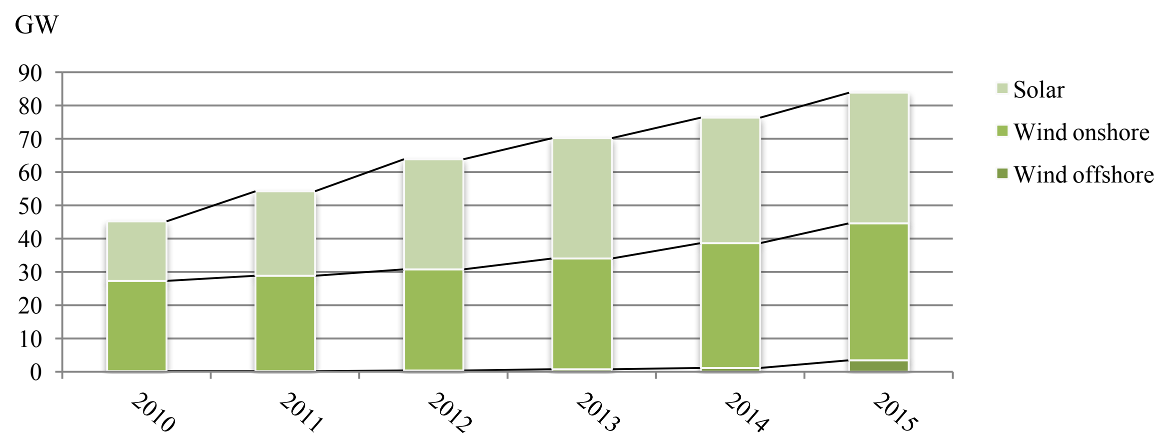

Figure 17 - German installed capacity of wind and solar generation between 2010-15 (Fraunhofer ISE, 2015).

6.4. Wholesale energy markets

6.4.1. Forward market

The wholesale energy market comprises three markets, of which the forward market is the one facilitating trades furthest ahead of delivery time. It is a continuous market on which predominantly financial contracts are traded, only sometimes involving a physical energy exchange. In case energy exchanges are traded, the outcome is a generator production schedule of MWs to produce at a certain hour. Market clearing, i.e. matching of bids and offers, is based on the merit order principle (see Annex A). The trading is typically done via (private) bilateral contracts but also via the various power exchanges introduced earlier. These contracts are generally settled at the day-ahead spot price (Just and Webber, 2012). It is estimated that for large industrial consumers, with a consumption larger than 150 GWh per year, about 80% of their power requirements is purchased on through forward long-term contracts, while spot market purchases, elucidated in the next section, make up for the 20% (Ecofys and Fraunhofer, 2015).

Figure 18 shows wholesale electricity prices over the last years, and reveals a declining trend. One might assume that it is the rise of renewables specifically that caused the decreasing wholesale prices. This is not the case however, as renewables have rarely set the market price. Though these resources are early in the generation merit order, they have limited dispatch ability, and therefore almost always push other resources to the margin. It is thus the marginal cost of more flexible units (the ones being pushed to the margin) that set the actual (future) market clearing prices (Agora, 2015). Renewables due put downward pressure on the wholesale price though, by pushing more expensive generation out of the market (NREL, 2016). Other factors that contributed to the lower electricity prices were a falling demand due to mild winter weather and increased energy efficiency, as well as lower commodity prices like oil and gas.

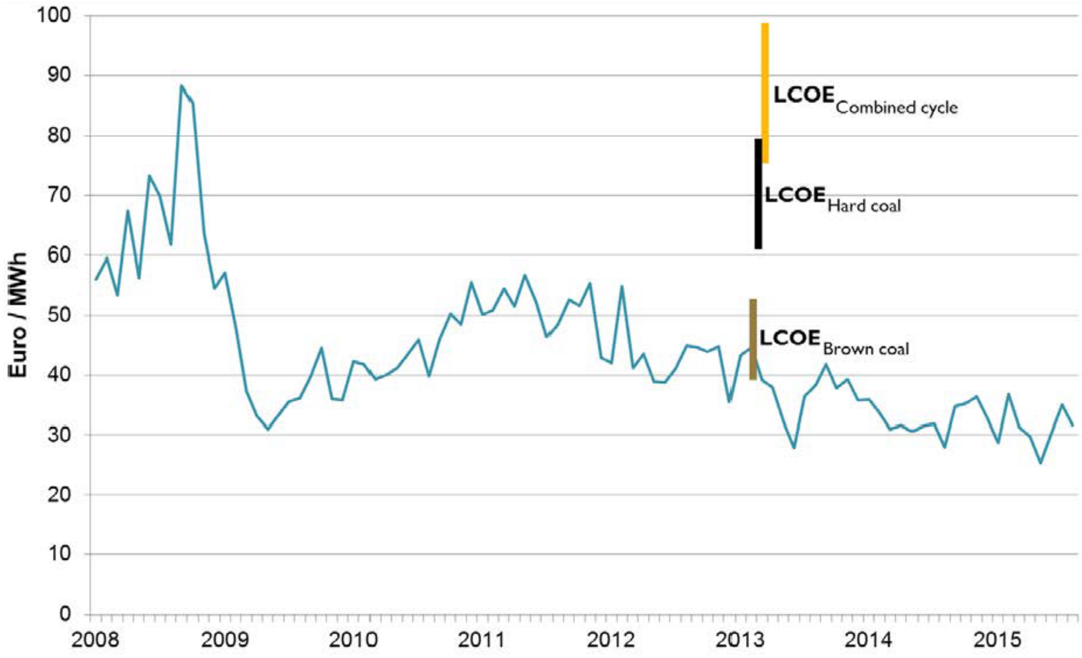

Figure 18 - Monthly average German wholesale electricity prices show a decreasing trend over the period 2008-15 and are currently under 40 €/MWh, which is one of the lowest in Europe (NREL, 2016).

Despite decreasing wholesale electricity prices, the retail prices, paid by consumers, have increased. One of the contributing factors is that extra levies are charged to finance the heavy renewable support schemes and FiTs (NREL, 2016). The average volume-weighted retail price in 2014 exceeded 29 c/kWh, making it the highest in Europe after Denmark. Electricity prices vary significantly for industrial consumers though, through exemption schemes of taxes and levies (Ecofys and Fraunhofer, 2015).

Figure 19 shows an overview of the sequence of market transactions in the German electric power system. The day-ahead market and continuous intra-day market are explained in the two upcoming subsections.

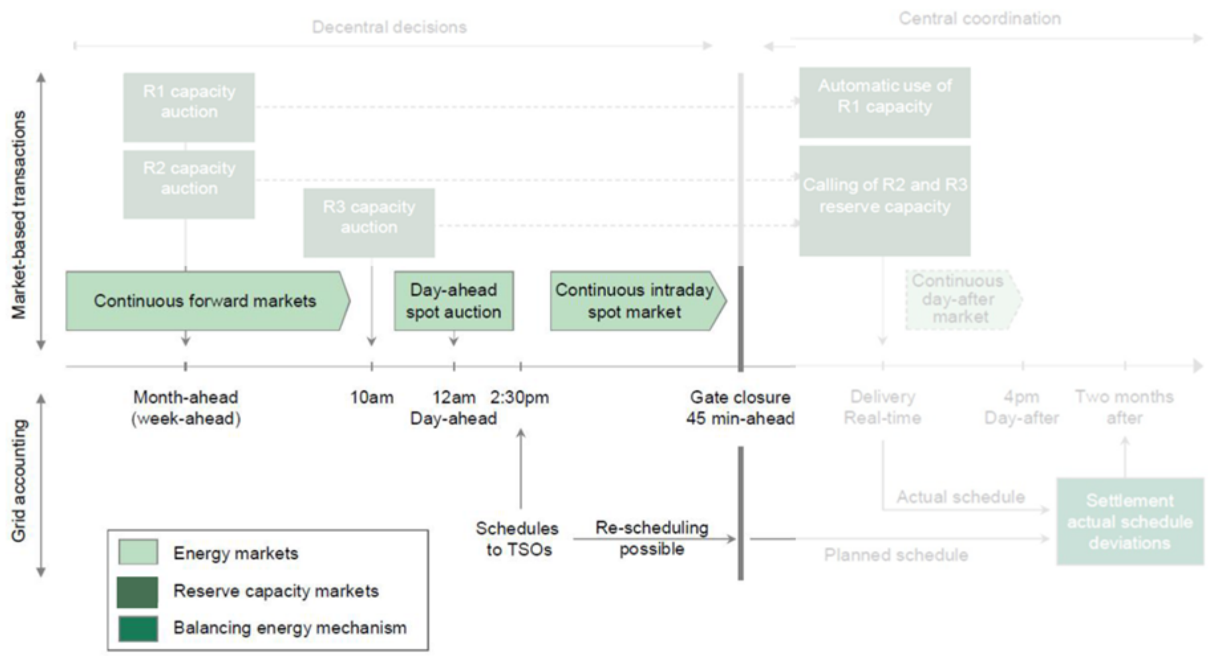

Figure 19 – Overview of German electricity markets and bidding sequences (Just, 2015). This subsection treated the coloured areas, the transparent areas treated in next sections.

6.4.2. Day-ahead market

The day-ahead (spot) market, or DAM is offered by several German power exchanges on the day before delivery. Electricity is traded for all locations and hours of the day of delivery. A single-price settlement scheme with 15 minute periods (per-time-units, or PTUs), again based on the merit-order principle (see Annex A), is implemented in each of Germany's four control areas (corresponding to the TSOs' covering regions). The outcomes of the market clearing are renewed obligatory production or dispatch schedules. Generally, the market is opened for a few hours around noon. The purpose of the market is to increase liquidity and accumulate volume, making it easier for buyers and sellers to find each other. In 2011 approximately 40% of total consumption was traded through these day-ahead auctions (Just and Webber, 2012).

The electricity quantity cleared on the DAM is based on demand forecasts and regulated by the market operator to secure the supply and demand balance. When the day-ahead spot market is closed, all market participants (technically all balancing groups (BRPs) – entities allowed to trade on the electricity markets) have to submit their quarter-hourly energy schedules to the TSOs, who will then check the feasibility of the expected power flows.

6.4.3. Intra-day market

The intra-day market facilitates the last market-based transactions before the generation dispatch schedules become fixed and binding. Generators without sufficient free resources in their own portfolios can turn towards the intraday market to trade their energy transaction obligations and make changes to their production schedules. The intra-day market runs until 45 minutes ahead of delivery, referred to as gate closure. After gate closure the TSOs take over the responsibility for the balancing of supply and demand (Just and Webber, 2012).

6.4. Reserves and ancillary services market

6.4.1. German system balancing

When the electricity schedules of the German BRPs are submitted to the TSOs at the closing of the day-ahead market for each PTU of the next day, the German system is balanced (from a planning perspective) as each BRP has to be balanced on PTU basis. After the intra-day market gate closure, the responsibility for a balanced system is transferred to the TSOs. The actual activation of corresponding balancing energy bids in real-time is also the task of the TSOs, as is the ex-post settlement of imbalances which is covered in the next subsection.

Before 2008 Germany's four control areas were individually responsible for maintain grid balance and the activation of any balancing power required. In 2008 the Grid Control Cooperation (GCC) was implemented with three of the four TSOs in order to be able to net the control areas' respective imbalances and consequently reduce the activation of balancing power. In 2010 the fourth control area joined the GCC, covered by TSO Amprion (Agora, 2015). Since then the GCC functions as a single 'virtual' control area covering whole Germany. In 2011 the International Grid Control Corporation (IGCC) was formed. Through this agreement the TSOs from Germany, the Netherlands, Czech, Denmark, Switzerland, Austria and Belgium cooperate to net their imbalances and reduce the need for balancing power (Ocker and Erhardt, 2015).

6.4.2. Reserve market

ENTSO-E's Network Code on Load Frequency Control and Reserve defines three processes for maintaining system frequency and keeping the system in balance, shown in Figure X. The German balancing mechanism follows this hierarchy, with the exclusion of reserve replacement (RR) which does is not defined in Germany. Frequency containment reserve (FCR) and frequency restoration reserve (FRR) have their German equivalents.

On the German reserve market three balancing or reserve products exist. The products differ in required activation speeds, required technical requirements and the types of auctions through which they are traded. The following three balancing or reserve mechanisms can be identified (VDN, 2007) and are elucidated in detail in the next subsection:

1. FCR or primary reserve (*Primärregelleistung*)
2. Automatic FRR (aFRR) or secondary reserve (*Sekundärregelleistung*)
3. Manual FRR (mFRR) or minute reserve (*Minutenreserveleistung*)

It should be noted that the terms for German minute reserve vary. Regelleistung, the German online platform on which reserve data is traded, names it minute reserve. In literature the German minute reserve is sometimes designated as RR or tertiary reserve though (Just, 2015).

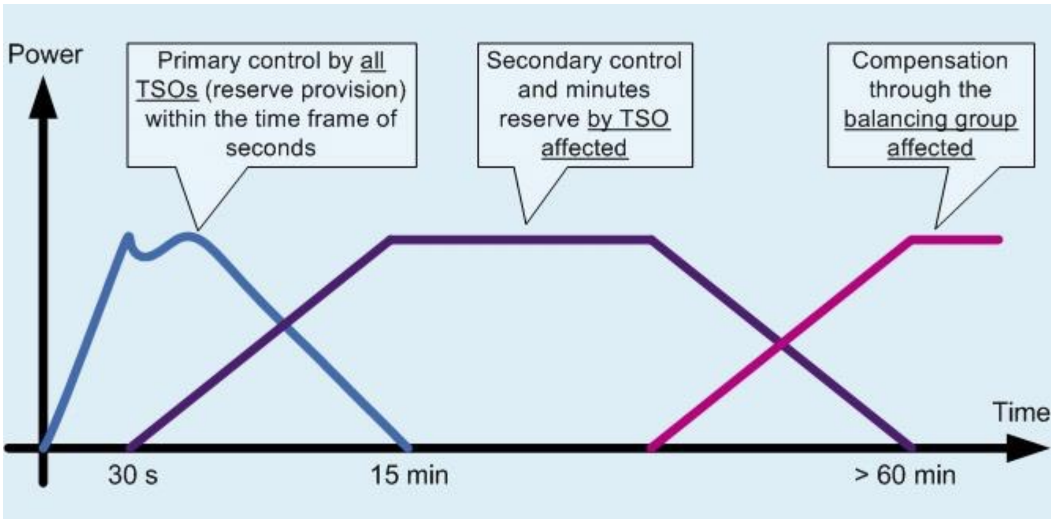

Figure 20 - Active power balance and reserve products (ENTSO-E, 2015).

Participating in the German reserve power market requires generation plants to meet high technical standards which they have to prove through so-called prequalification procedures. It can be costly and can last up to a year to get through the prequalification procedure (Hein and Goetz, 2013). Due to the strict requirements only few generation plants are licensed to provide their capacities as reserve power (VDN, 2007). Just (2015) shows that between 2014 and 2015 on average there were 19 participants in the primary reserve market, 29 participants in the secondary reserve market and 41 participants on the tertiary reserve market. Regulatory authorities are currently exploring options for the opening of the secondary and minute reserve market to renewable generation including solar and wind (BMWi, 2015), which is successful would probably result in significantly more participants in these markets though with their, inherent to renewables, limitations of supply. Figure 21 shows the TSO's reserve demand through the last decade where Table X provides the specific values for 2015.

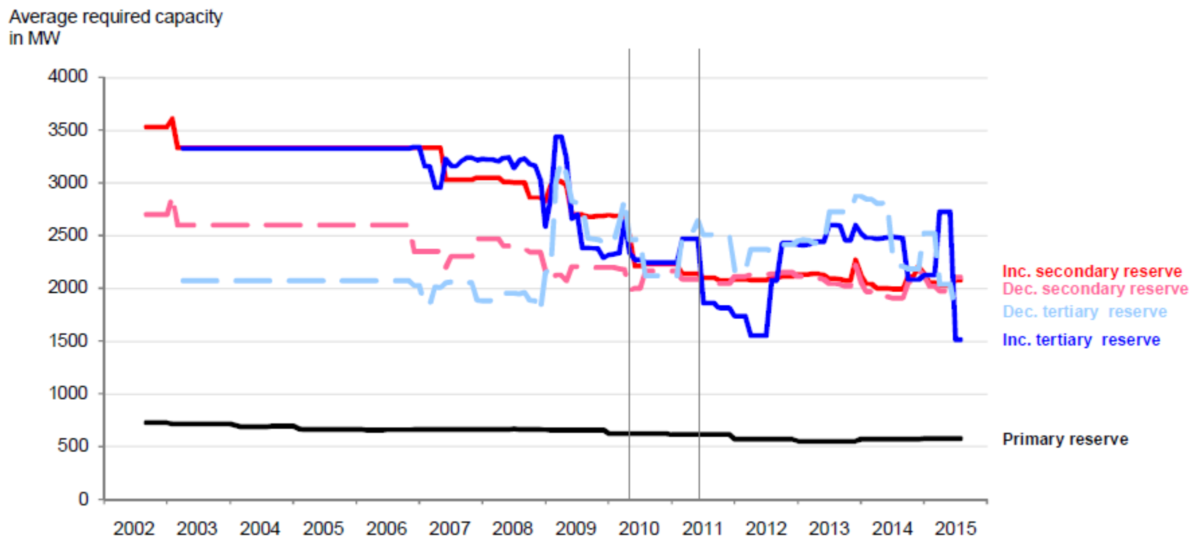

Figure 21 - Demand for German reserve capacity per TSO (Just, 2015).

Table 11 - Contracted German reserve capacities in 2015 (Just, 2015).

	Upward [MW]	**Downward** [MW]
Primary reserve	3000	3000
Secondary reserve	8304	8412
Minute reserve	6052	7128

6.4.3. Reserve product overview

Tables 12, 13 and 14 provide overviews of the characteristics of the three German reserve market products. The German reserve market uses multi-bid auctions for awarding both secondary reserve contracts. The awarding of secondary reserve contracts, both aFRR and mFRR, is based solely on the capacity prices. When balancing energy is required from the contracted balancing parties the activation is based on the merit-order principle, and as many bids as required to cover demand are activated (Hein and Goetz, 2013).

Table 12 - Primärregelleistung (Primary regulation - FCR).

Technical requirement	Single product with a symmetrical regulation band; any MW of capacity offered must be available both upwards and downwards. If selected in the auction, participants must keep their committed reserve capacity available during the entire contract period throughout the week in question. ▪ Full activation within 30 s ▪ Ability to sustain required reserve capacity for 15 min ▪ Activated proportional to frequency deviation (by all TSOs in synchronous areas) (fully activated at a 200 mHz deviation) ▪ Minimum bid size of 1 MW
Eligibility	Every unit that meets the technical prequalification criteria can participate in the tenders. Pooling of units is only allowed within a single control area. This allows individual units (smaller than 1 MW) to participate.
Procurement	Market-based through weekly tenders, based on a merit-order list where capacity bids are sorted by increasing capacity prices.
Remuneration	There is no remuneration for actual energy deliveries after activation. Remuneration for capacity is based on pay-as-bid; prices paid to winning suppliers are based on their actual capacity bids, rather than the bid of the highest priced supplier (For this reason, pay-as-bid auctions also are known as "discriminatory auctions" because they pay winners a different price tied to the specific prices they offer into the auction.).

Table 13 - Sekundärregelleistung (Automatic secondary regulation - aFRR).

Technical requirement	FRR is segmented into four products in Germany - separated by direction (upwards and downwards) and by time period (peak (08h-20h), off-peak (20h-08h), weekend days and public holidays). If selected in the auction participants must keep their committed reserve capacity available during the entire contract period throughout the week in question. ▪ Full activation within 5 min ▪ Ability to sustain required reserve capacity for 4 h ▪ Minimum bid size is 5 Mw
Eligibility	Every unit that meets the technical prequalification criteria can participate in the tenders. Provision is portfolio-based; pooling within and across control areas is allowed so that the minimum offer size requirement can be met.
Procurement	Market-based through weekly tenders, based on a merit-order list where capacity bids are sorted by increasing capacity prices.
Remuneration	Remuneration is provided both for capacity offered (pay-as-bid) and for balancing energy provided (also pay-as-bid), which is selected using the merit-order principle.

Table 14 - Minutenreserveleistung (Manual secondary regulation – mFRR).

Technical requirement	mFRR is segmented into 12 products in Germany – separated by direction (upwards and downwards) and by time slice (there are six 4-hour products). ▪ When required, mFRR is activated on a PTU-basis. If requested within the first 7.5 min of the current PTU, then it must be fully activated for the next PTU. If requested less than 7,5 min before the next PTU, full activation must occur only for the next but one PTU. ▪ Ability to sustain the required reserve for at least one PTU (and more if requested by the TSO). Ramping up and down should occur outside the PTUs where the service is required. ▪ Minimum bid size is 5 MW
Eligibility	All units eligible - Provision is portfolio-based.
Procurement	Market-based (occurring on a daily basis for day-ahead). Bids are contracted based on the capacity price offered. Activation occurs based on energy price of bid.
Remuneration	Remuneration is provided both for capacity offered (pay-as-bid principle), and also for any balancing energy that is activated using the merit-order principle (also pay-as-bid).

6.4.3. Balancing mechanism

A balancing or reserve energy mechanism distributes the costs of that reserve energy among the originators of the imbalance. Hence, it is close to an accounting procedure. Ex post the balancing mechanism determines all payments made to compensate for the imbalances (differences between generation or load schedules and actual grid offtakes or in feeds) of every balancing responsible part.

The total cost of both the activated upward and activated downward reserve energy is determined per control zone per quarter-hour. All balancing groups with a positive balance in this control area (an oversupply of energy) receive this balancing energy price and all undersupplied balancing groups in this control area have to pay for the missing energy. The costs are then distributed among the parties within that control zone that caused the imbalance, in proportion to the volume of imbalance they caused. This is referred to as the imbalance price (*Bilanzausgleichsenergiepreis* or reBAP in German). A control zone either has a downward balancing price when it is long (i.e. it was oversupplied) or an upward balancing price when it was short (i.e. it was undersupplied). As Germany is composed of a single control zone, at every quarter-hour the country has a single upward or downward imbalance price. The imbalance mechanism is thus a cost-based one-price system and a zero-sum activity for the TSOs as all reserve energy related costs are passed through the balancing groups (Just and Weber, 2012).

At times when much reserve energy is needed, and over 80% of the contracted reserve capacity is activated, either a surcharge or a deduction is applied to the imbalance price, depending on the positive or negative value of the balance of the activated control energy (Regelleistung).

6.4.4. Ancillary services market

In addition to balancing services there are three other main ancillary services. They relate to reactive power, the power component that transfer no net energy to the load and is due to inductive and capacitive components in the grid, to black start capabilities and redispatching. The latter is performed by the TSOs and refers to changing the operation schedules of generators when a technical analysis indicates risks of bottlenecks or transmission line overloads. This could for instance occur in the North of Germany, where conventional generators can be asked to reduce output to free the transmission lines for wind power feed-in. Generators asked to change their production schedules are reimbursed for the money they would've made from their original schedule, minus the savings on fuel costs (BNetzA website). All these ancillary services are procured via bilateral contracts between plant operators and German TSOs. Accompanying remunerations are based on the agreements between these parties.

6.5. Capacity markets and payments

Capacity mechanisms are implemented in an electricity industry to make sure that electricity supply can meet demand in the medium and long term. If cost and revenue prospects are too low, or if uncertainty is too high, investments in existing and new generation facilities may decline. A capacity mechanism can financially incentivize generators for getting additional generation capacity running or keeping existing generation online. The capacity payments can be specified as e.g. a series of payments or one-of payment per MW of generation power.

Currently Germany has an energy-only electricity market and there are no capacity payments in place. The establishment of a German capacity market has been subject of many debates in recent years though. The recent decision to phase out existing nuclear power plants by 2022 and the significant share of intermittent renewable generation has led to concerns about the supply reliability and the revenue adequacy for conventional generators. Felder (2011) shows that a large share of intermittent renewable generation can suppress electricity prices while providing relatively little extra capacity. The decreasing wholesale electricity prices, showed earlier in Figure X, have eaten into the revenues of the existing conventional generators so much that some of them might not even be covering their fixed costs (Weiss, 2014). The discussion about revenue adequacy and supply reliability is part of a larger trend within Europe to implement capacity remuneration mechanisms, including Belgium, the United Kingdom and France (NREL, 2016).

The German government published a white paper on capacity markets in Germany (BMWi, 2015). It was based on four expert studies, including Frontier Economics and Consentec (2014), in which different forms of and alternatives to capacity markets were assessed. Capacity markets were rejected for the primary reasons that (1) there is currently enough capacity in the system, (2) capacity markets could distort competition and (3) the poor cost effectiveness. Instead a capacity reserve system was suggested. This capacity or strategic reserve system would be comprised of 4 GW of generation capacity that would not operate on the electricity market but would only be activated when supply cannot cover demand at a certain time (BMWi, 2015).

Chapter 7. Impact of German regulation on electricity storage opportunities

This chapter provides an overview of how the regulatory framework treats different electricity storage facilities in the German electric power industry. As regulations are subject to constant changes the findings in this section can only be considered a snapshot at the moment of writing. The most important document for regulation is the EEG (2014).

7.1. Regulatory definition

A clear regulatory definition of electricity storage capability in the EnWG and EEG legislations is important to be able to differentiate it from other groups of grids users including end consumers, transmission and distribution operators and generators. BDEW (2014) explains that the definition of "storage facilities" in the EnWG is aimed at gas storage facilities. Electricity storage facilities are referred to with this definition in the EEG. Following a German court appeal in 2009 electricity storage facilities are treated as end consumers during times they are storing electricity and as generators when they are feeding energy back to the grid (BDEW, 2014). In summary, there is no clear regulatory definition available for electricity storage available yet.

7.2. Market participation

BRPs are allowed to participate in all the wholesale electricity and ancillary service markets as long as they meet the technical requirements for the traded products. This includes minimum delivery times (ramp rates) and minimum bid sizes, as was highlighted for the different reserve markets in Chapter 6. As almost all electricity storage technologies have high ramp rates that easily meet these technical requirements. Bid sizes could be a barrier though, as individual electricity storage facilities are relatively small. As most of the provision of services is portfolio-based rather than unit-based the minimum bid sizes can easily be met nonetheless.

7.3. Eligibility for support mechanisms

The EEG specifies the eligibility of different renewable generation technologies for support mechanisms, which includes feed-in tariffs (FiTs) and levy and surcharge exemptions. As there is no clear regulatory definition of electricity storage its eligibility for support mechanisms is not mentioned explicitly. PSH, being rather considered a renewable generation technology instead of an electricity storage technology, is mentioned in paragraph 40 where its feed-in tariffs are presented. For PHS the feed-in tariffs decrease with the plant size. A PSH plant with a capacity larger than 50 MW is eligible for a FiT of 3,5 eurocents/kWh.

Regarding electricity storage, the EEG (2014) states in Part 3 – Section 19 that operators of renewable energy installations can apply for financial support mechanisms like feed in tariffs (FiTs) or premiums even if the electricity has been stored temporarily before being supplied to the grid. In this case the tariffs or premiums apply that would have been given to a renewable energy source supplying energy directly to the grid. An obvious shortcoming of this regulation is how to verify and ensure that the energy stored is exclusively generated by a renewable energy source. The new EEG 2014 furthermore specifies that renewable energy generation continues to have priority grid connection which is thus applicable on PSH (Martinot, 2015).

At the moment of writing this report, the German regulators are experimenting with replacing the FiTs with an auction-based system to introduce market-based incentives in the support mechanism. The resulting market premiums force the renewable generators to sell directly to the grid and are then paid on top of the price the generators receive in the market. In the early stages the level of the market premiums will be determined by reference to the FiTs. As it looks like hydro power is excluded from these changes as there it was deemed to have too little competition to efficiently introduce market-based incentives.

7.4. Transmission charges and levies

The EEG levy or surcharge is a renewable surcharge used to finance renewable support mechanisms. In Part 4 – Section 60 the EEG (2014) regulates the exemption of electricity storage facilities from the EEG levy (e.g. pumped storage power plants and battery storage facilities), if the stored electricity is exclusively fed back into the grid from which it is originally drawn. Power-to-heat or power-to-gas facilities do not profit from this exemption.

Germany charges the grid users transmission tariffs or grid fees, specified in the EnWG, to cover the cost of electricity losses, grid infrastructure, system services and other regulatory charges. Price discrimination allows certain group users, including energy-intensive consumers consuming more than 10 GWh and consumers using little or no power for a large part of the year, to be exempt or benefit from a reduced grid fee. There is also a spatial variation in the charges. At the moment the

EnWG specifies in Section 60 that pumped-hydro storage plants commissioned within a 15-year period from August 2011 are exempt from transmission charges during a period of 20 years. A bill was recently submitted though to extend this to 40 years. Pumped-storage plants that have increased their storage capacity by at least 5% or their turbine capacity by at least 7,5% since August 2011 are also exempt from the transmission charges, though for a period of 10 years. A bill was recently submitted to extend this to 20 years.

Other electricity industry levies for which no exemptions or reductions could be identified for electricity storage facilities are (Ecofys and Fraunhofer, 2015):

- Concession fee – used to compensate municipalities for the usage of their public transport routes
- CHP levy – funds the support mechanism for combined heat and power (CHP) generation
- StromNEV levy – funds the costs of the exemption from or reduction of the transmission tariffs for some consumers
- Offshore levy – funds the service compensation that network operators have to offer since 2013 in the case of interference or delay in the connection of offshore wind farms.
- AblaV levy - covers the costs of interruptible loads used to maintain system and grid reliability and stability.

7.5. Ownership restrictions

Because of unbundling requirements TSOs are not able to own generation assets. Potential electricity storage owners can thus not be active in transmission activities. Under specific circumstances it is allowed for TSOs to own electricity storage capabilities as long as they are operated outside of the electricity markets. This is elucidated in § 8 paragraph 4 of the Reserve Power Plant Regulation (*Reservekraftwerksverordnung*) which is valid until the end of 2017.

Any merger or acquisition in Germany by a foreign company is subject to merger and competition control by either the Federal Cartel Office or the European Commission. Furthermore, the BMWi has the authority to review any acquisitions of German (energy) companies by non-EU purchasers not in the European Free Trade Association. To protect the energy needs of Germany, the BMWi can prohibit foreign acquisitions or impose restrictions. In spite of the importance of the electricity market the BMWi has never had to intervene in any foreign investments in this market (Uwer and Zimmer, 2014).

7.6. Plant construction and operation authorization requirements

Uwer and Zimmer (2014) provide an overview of the authorisation requirements for the construction of an electricity generation plant. The following permits must be obtained:

- A permit under the Federal Emission Control Act (*Bundes-Immissionsschutzgesetz*, or BImSchG) including an environmental impact assessment.
- A building permit under the Federal Building Act (*Baugestzbuch*) and the building acts of the relevant state (*Landesbauordenung*).
- If applicable, water discharge and abstraction permits under the Federal Water Act (*Wasserhaushaltsgesetz*, or WHG) and the water acts of the relevant state (*Landeswassergesetze*).

An interesting report from Sauer et al. (2015) about the lessons learned from the construction of a 5 MW battery project in Germany shows that especially the building permit can be cumbersome to obtain, mainly due to the lack of experience at the certifying authority.

Any operating permits are already included in the construction permits, although specific conditions and requirements can be formulated in addition. From December 2012 onwards the final shutdown of a generation plant with a nameplate capacity larger than 10 MW must be reported to the TSO of the control area where the plant is connected to the grid and to the Federal Network Agency (BNetzA) at least twelve months in advance. In case the plant is deemed essential for maintaining security of supply the shutdown can be prohibited if technically and legally feasible (Uwer and Zimmer, 2014).

Chapter 8. Modelling and analysis of future reserve market opportunities

8.1. Scope limitation to secondary reserve market energy payments

StRe@M evaluates two potential revenue streams for the generation technology and scenario it is applied to, as was explained in Chapter 5. The first revenue stream comes from trading on the day-ahead spot market. The second revenue stream comes from the secondary reserve market, and this is where the Imbalance Forecaster is required.

After the background study of the German electricity markets the decision was made to limit the scope of the reserve market revenue stream to the secondary reserve (in Germany, aFRR) market. It was outside the time scope of the first version of StRe@M to incorporate additional ancillary service markets in the model like primary, tertiary or black start services. There are three primary reasons for considering the secondary reserve market instead of any of other ancillary service markets.

Firstly, good data is generally available for secondary reserve markets in most European countries including Germany, which would mae a comparison between the results of this German case study and the results of possible future expansions of StRe@M to other countries possible.

Secondly, the literature study showed that the existing models that assess electricity storage revenues and incorporate an ancillary service market almost all modelled the secondary reserve market. Pinto et al. (2011) modelled the revenues from the day-ahead market as well as the different ancillary service markets. The model showed that the biggest source of income for a PSHP in the Portuguese electricity market was the secondary reserve market. As the primary generation technology to be assessed with the StRe@M project is (variable-speed) pumped-hydro-storage this study's result seems relevant. Other studies, like Chazarra et al. (2014) also use Pinto et al.'s findings and model the revenues from a variable-speed pumped-hydro-storage in the Iberian market using the day-ahead market and the secondary reserve market.

A third reason is the relative market size of aFRR compared to the other German reserve products. ENTSO-E (2015) shows that between February and June 2015 over 80% of all three Germany's deployed reserve volumes (from FCR, aFRR and mFRR) was aFRR. Just (2015) further shows that in Germany in 2015 the total size of the secondary reserve market, including payments for both capacity and energy, covered approximately 50% of the total reserves cost. The tertiary reserve market was second largest. In addition to having the biggest market size, which theoretically would make the market more attractive from an investor's or operator's perspective, there are actually also less market participants active on the secondary reserve market than on the tertiary reserve market. If a technology meets the technical requirements to enter the secondary reserve market this therefore seems a bigger market opportunity than the tertiary reserve market.

It should be noted that both Pinto et al. (2011) and Chazarra et al. (2014) analysed historical data to come to their conclusions, whereas StRe@M will look at future scenarios. For the design of the first version of StRe@M it is assumed that the structure of the ancillary service market in the modelled future years is the same as the structure of the ancillary service market today. This seems well possible for the first couple of years after 2020, but when advancing towards 2030 and onwards it becomes more uncertain. The argument to still consider the ancillary market as it is shaped today is a practical one though: any changes in the market structure are difficult to foresee or translate into scenarios and models (staying within the scope of the StRe@M project). If, in the future, ancillary market reforms occur StRe@M can be updated to improve accuracy and stay relevant.

In order to assess if there are market opportunities on the secondary reserve market in future years, and if any potential revenue can thus be made, two questions need to be answered. Is there a market? In other words, how often and how much will be secondary reserve energy be activated by the TSO? And secondly, what is the price at which the service is procured? The potential revenue to be made by a generator operator is of course dependent of the sales volume and the sales price. The Imbalance Forecaster is designed to answer these questions. The Imbalance Forecaster forecasts the future activated secondary reserve volumes to assess if there is a market opportunity for a generator operator. Belonging to these forecasted imbalance volumes a price is forecasted too, to assess the potential revenue.

8.2. Identification of system imbalance drivers

Borggrefe and Neuhoff (2011) identified unscheduled plant outages, intermittent generation forecast errors and load forecast errors as main (stochastic) drivers for system imbalances. Hirth and Ziegenhagen (2013) mentioned these same drivers, although they considered the forecast errors for all generation (not just intermittent) and added a fourth, deterministic, driver, namely the so-called structural imbalance.

Table 15 - System imbalance drivers identified by Hirth and Ziegenhagen (2013).

Stochastic	Deterministic
Generation forecast errors (of conventional generation)	Structural imbalance
Load forecast errors (of intermittent generation)	
Unexpected plant outages	

The first identified system imbalance driver is the forecast error resulting from generation. Forecast errors are the unexpected deviations from previously forecasted production values. As the production forecast errors of conventional generation are very small, because of the controllability of the process, the total generation forecast error is mainly determined by the contribution of intermittent generation. Operators of intermittent generation capacity rely on (advanced) weather forecasts, specifying wind speed and solar irradiance, to estimate their production (schedules). When, on the day of delivery, the forecasted production for a few hours later threatens to be incorrect the operators can adjust for this on the intraday market. As gate closure approaches the forecast errors become smaller but they are never perfectly accurate. The deviations from the production schedules will drive system imbalance. Forecast errors in load are also a relevant driver of system imbalance. Consumer behaviour can be unpredictable at times, which can result in unexpectedly low or high load and a resulting system imbalance.

Unscheduled plant outages are stochastic processes that influence the potential mismatch of load and generation. The probability of occurrence depends on the type and wear of the generating plant. The wear is influenced by things like age, maintenance and operation of the plant. When an unscheduled outage occurs the short-term (real-time up to a few hours) scheduled production has to be supplied by reserves as no market is available to adjust deviations from the production schedule.

A fourth effect is the structural imbalance. This is caused by the continuous change of grid load and the discrete scheduling of production. In Germany all generators have to provide their production schedule to the TSO on the day before delivery and on a quarter-hourly basis. As the load changes, continuously, and not in quarter-hourly steps, there is always a looming imbalance. A market rule that worsens this effect is that some (day-ahead) spot exchanges have hour granularities. Generators therefore resort to using hourly schedules, even though quarter-hourly production schedules have to be sent to the TSOs. The result is even higher deviations, occurring especially at the beginning and end of an hour (Consentec, 2010; Weißbach and Welfonder, 2009). No clear quantification of the effect of structural imbalance on actual system imbalance sizes could be found in the literature though. Fattler and Pellinger (2015) do show that between January 2011 and December 2014 an average of 18,6 GWh of positive and 3,7 GWh of negative secondary reserve was required to compensate for the structural imbalance, which corresponds to an average of 14, respectively 1,95 % of the total demand.

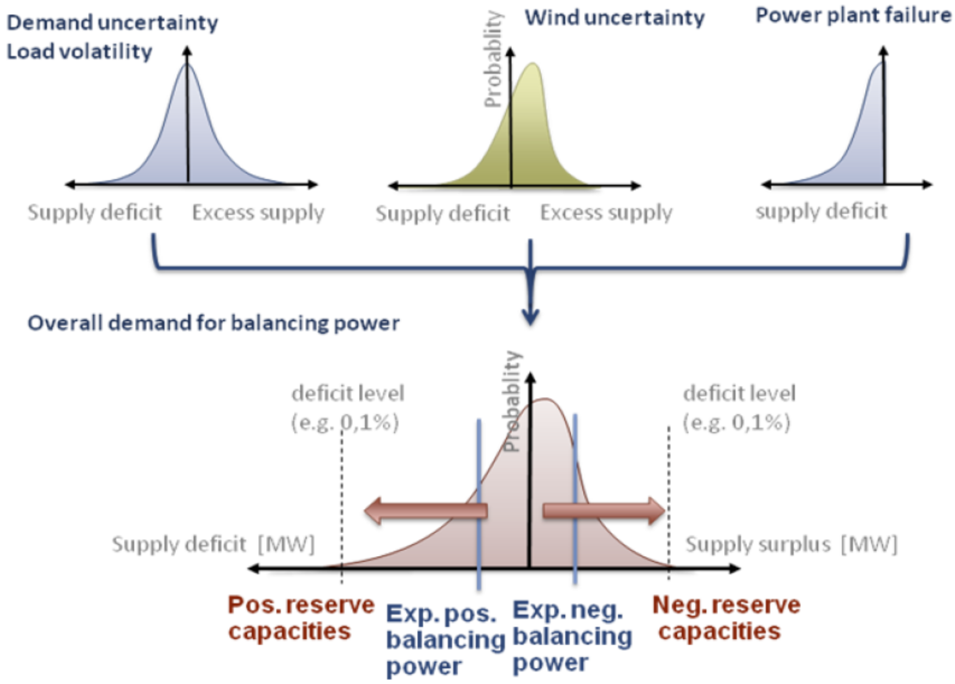

Figure 22 - Balancing power drivers identified by Borggrefe and Neuhoff (2011).

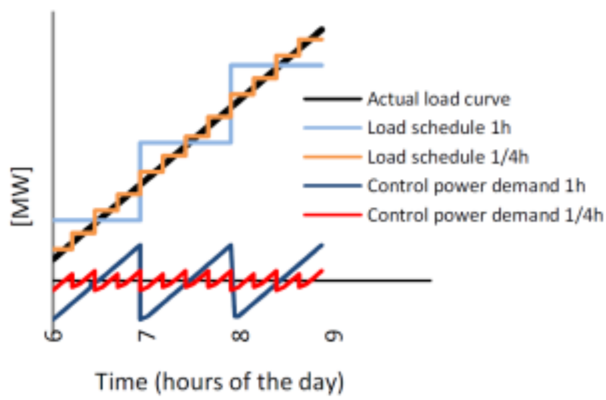

Figure 23 - Structural imbalance formation (Hirth and Ziegenhagen, 2013).

8.3. Forecast errors to forecast system imbalances

8.3.1. Quantified relation

Both Borggrefe and Neuhoff (2011) and Hirth and Ziegenhagen (2013) do not present any quantitative relation between the system imbalance drivers and the actual system imbalance value. They do imply that there is positive causality; bigger forecast errors and larger structural imbalance will contribute to a higher system imbalance.

A quantitative relation is required for StRe@M though in order to be able to forecast future imbalance values and thereby determine if there is a secondary reserve market. To explore these relations quantitatively historical time series data of forecasted and actual production of intermittent generation and the resulting forecast errors is compared to system imbalance volumes. In countries where relatively much intermittent generation is installed the forecast errors of conventional generation might not have to be considered in the initial analysis because the relative controllability of conventional generation technologies their forecast errors are expected to be much smaller than the forecast errors of intermittent generation and can hence be neglected.

8.3.2. Forecast error and system imbalance comparison

A data set was constructed for 24h-ahead forecast errors in the German grid in 2015 for:

- Wind onshore production
- Wind offshore production
- Solar production
- Load

This data was complemented with data for the German system imbalance (*Regelzonensaldo*) during 2015. As quite some processing was required Annex B provides a detailed overview of the gathering, processing and description of this data set.

A first check to see if wind and solar forecast are indeed main drivers of system imbalance, also called area control balance, is plotting the time series of both forecast errors and system imbalances in one plot. Figures 24-27 shows two weeks in 2015 with the sum of the forecast errors for wind and solar generation and load summed and plotted against the registered system imbalance. A positive system imbalance corresponds to a deficit supply and thus the purchase of balancing energy. The forecast errors are computed as the difference between the 24h-ahead forecasted generation values and the actual generation values. A positive forecast error thus corresponds with a supply deficit.

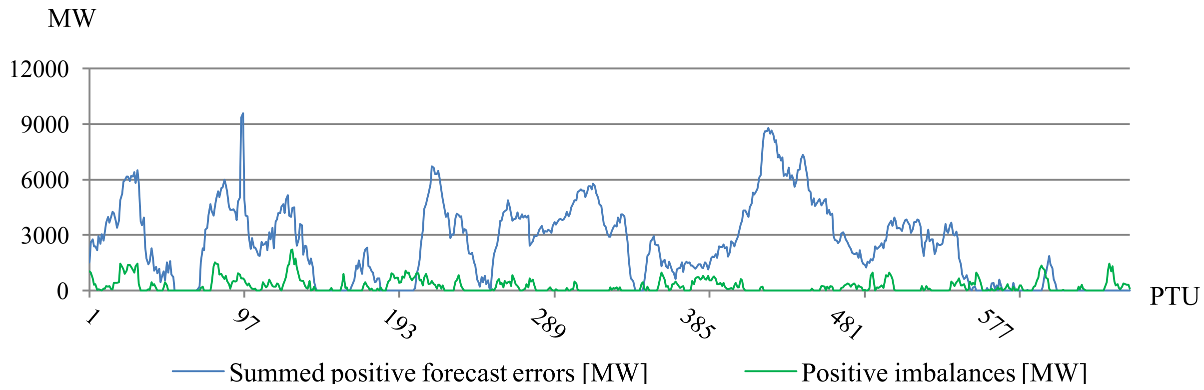

Figure 24 - Summed positive forecast errors and positive system imbalances in Germany for April 1-7, 2015 (ENTSO-E, 2016).

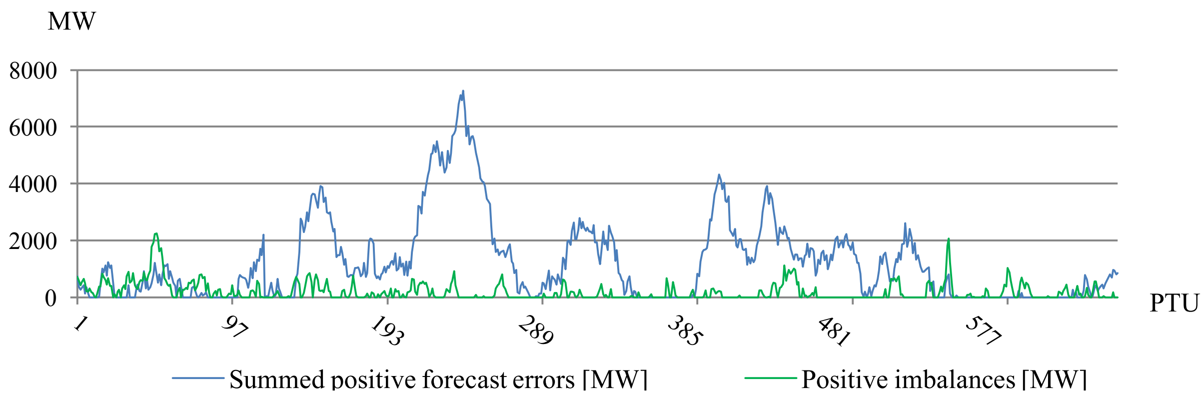

Figure 25 - Summed positive forecast errors and positive system imbalances in Germany for September 1-7, 2015 (ENTSO-E, 2016).

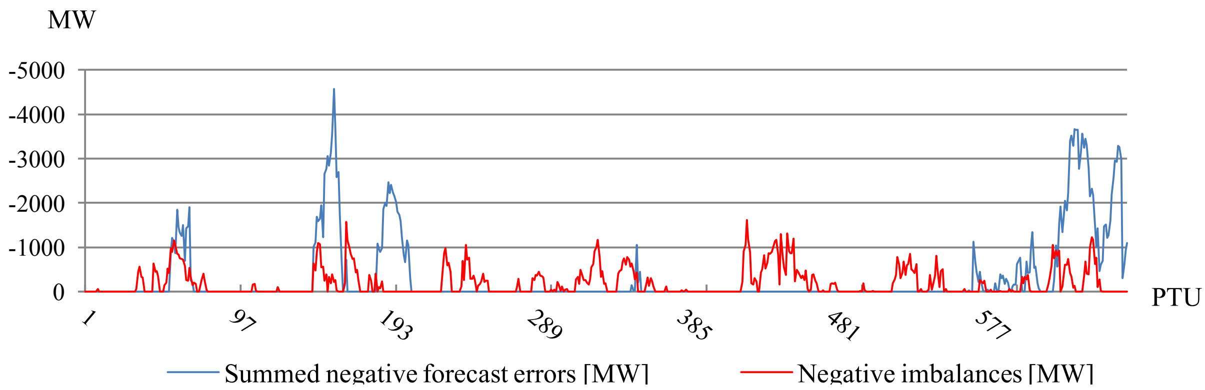

Figure 26 - Summed negative forecast errors and negative system imbalances in Germany for April 1-7, 2015 (ENTSO-E, 2016).

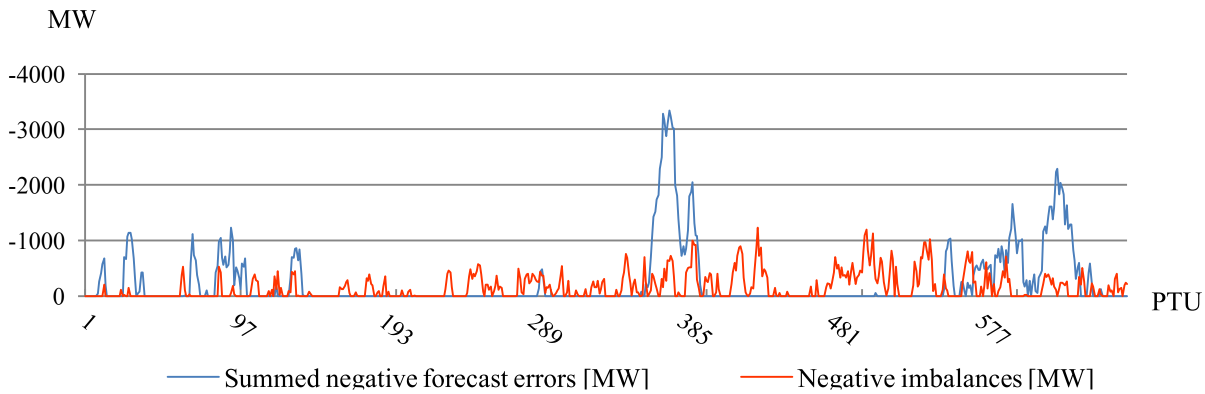

Figure 27 - Summed negative forecast errors and negative system imbalances in Germany for September 1-7, 2015 (ENTSO-E, 2015).

At first sight the time series seem to shows no relation. A better way to highlight this is by looking at the respective scatter plots. The resulting scatter plots are presented in Figure 28. No clear relation can be identified either.

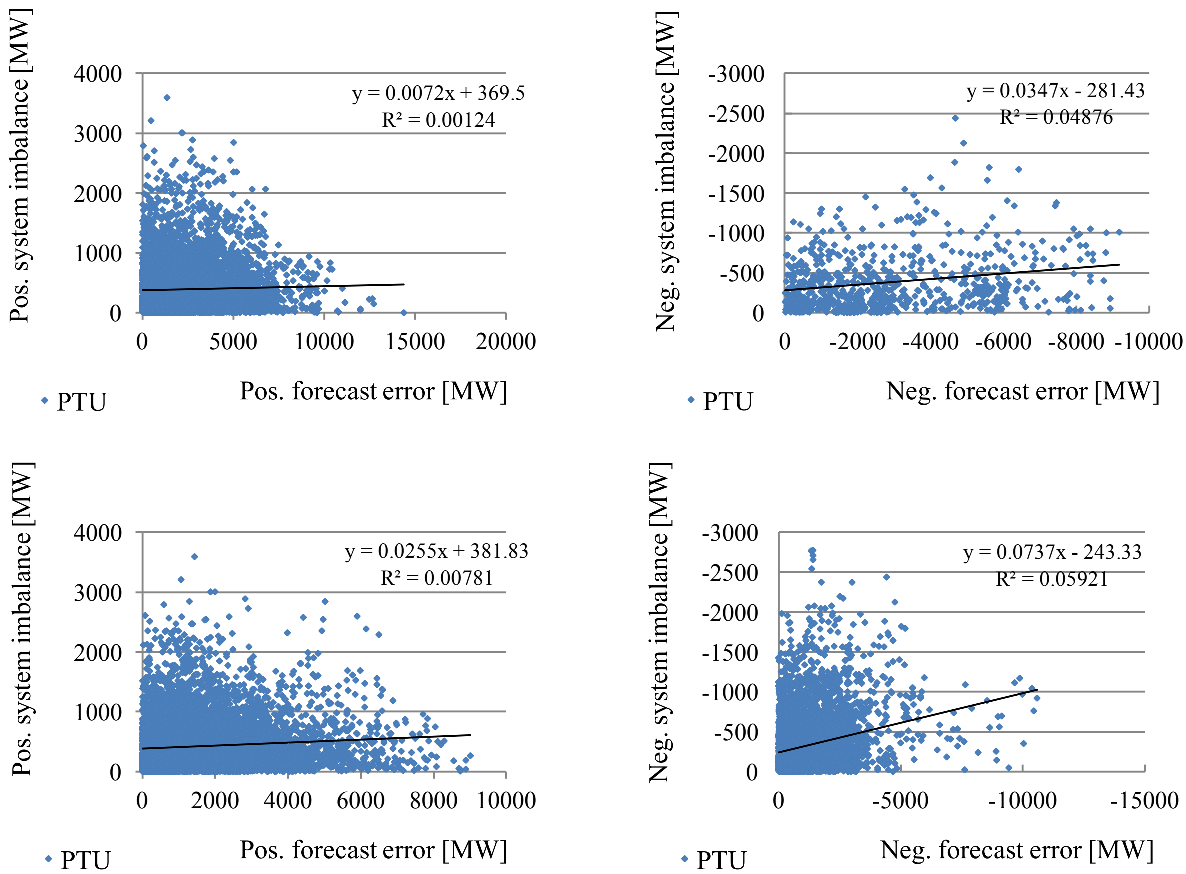

Figure 28 - Sum of forecast error versus system imbalance for all available PTUs in 2015. The top plots consider forecast errors from wind, solar and load. The bottom plots only consider wind and solar for the forecast errors.

A relation was also investigated between forecast errors and activated aFRR directly. The resulting scatter plots are presented in Figure 29.

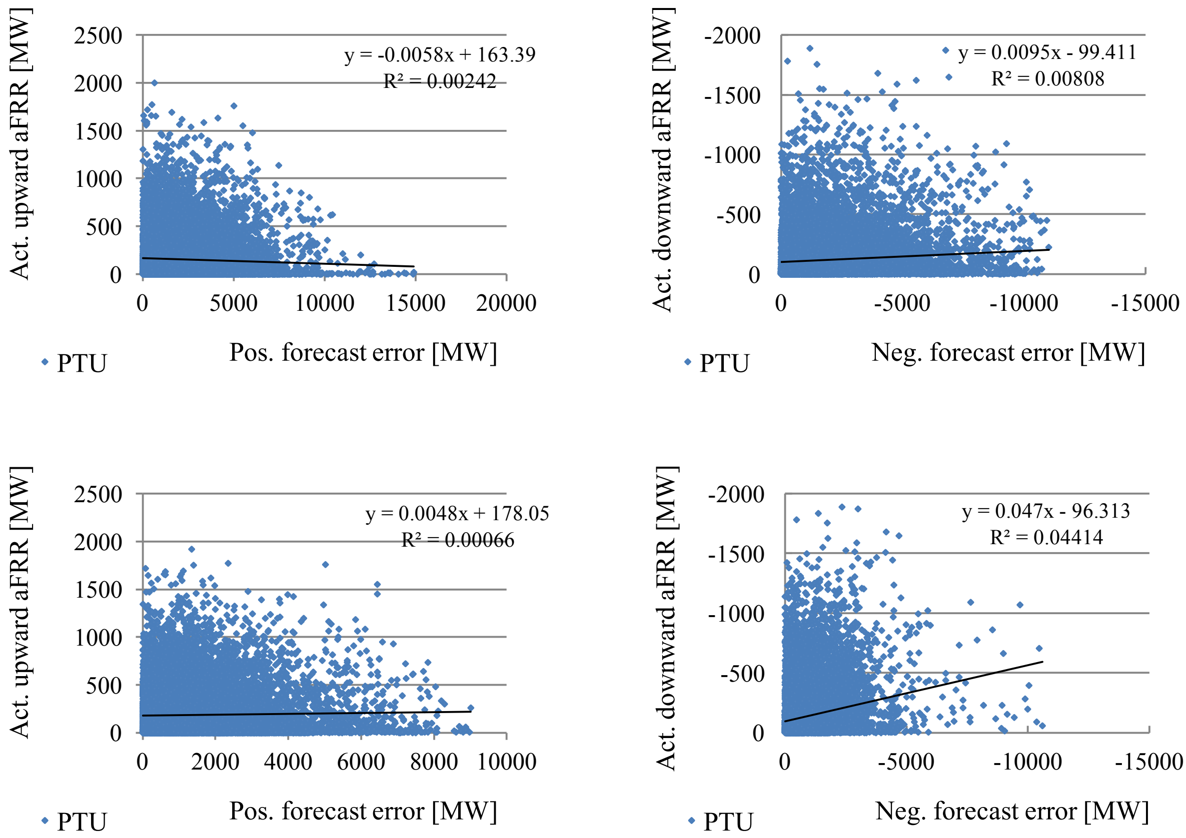

Figure 29 - Sum of forecast error versus activated aFRR in Germany for all available PTUs in 2015. The top plots consider forecast errors from wind, solar and load. The bottom plots only consider wind and solar for the forecast errors.

Also here, no relation could be identified. This analysis was also fully extended to Belgium and also there no significant relation could be identified. At this point consideration was given to also incorporate the structural imbalance in the above analysis by adding them to the forecast errors. This was not done because the relative effect of the structural imbalance has been small historically, following the analysis of Fattler and Pellinger (2015).

Instead additional research was performed to map additional factors, besides the unexpected outages and structural system imbalance mentioned earlier, that possibly influence system imbalances.

8.4. Other factors influencing system imbalance

8.4.1. Forecast changes

The forecast errors in the previous analysis were 24h-ahead forecasts. Forecasts are computed almost until real-time though, to help system operators prepare for supply and load levels. The forecasts get more accurate as they approach real-time. The 24h-ahead forecast used for the comparison earlier would thus be an upper limit for the difference resulting from forecast errors.

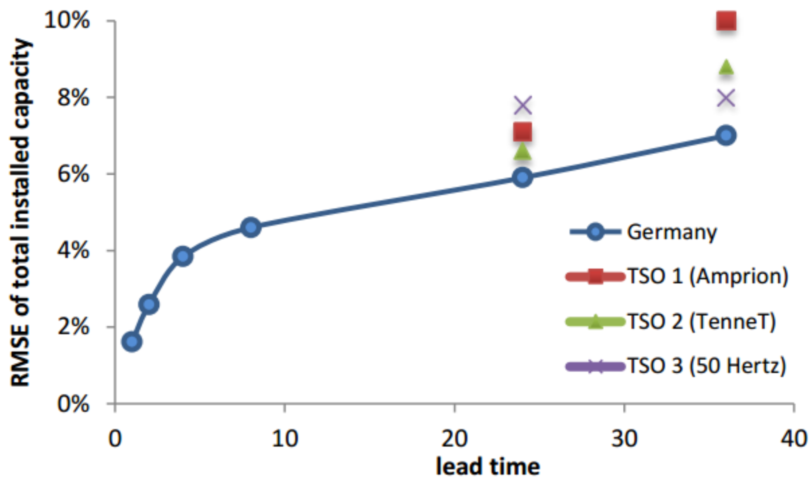

Figure 30 - Forecast error changes (Borggrefe and Neuhoff, 2011).

8.4.2. Intraday market

The intraday market is the last resort for market participants to make changes to their generation schedules and avoid schedule imbalances and regulatory penalties. It is thus the place were looming imbalances can be solved by the BRPs, caused by for instance forecast errors, to avoid engaging in the imbalance mechanism and the accompanying regulatory penalties. A liquid intraday market, where many buyers and sellers are active, improves the likelihood for BRPs of solving any deviations they expect in their production schedules. Own analysis showed that the total volume of the 24h-ahead forecast errors was 18 TWh, about 3 % of the total German production, whereas the total volume traded on the intraday market was 42 TWh. Looking at volumes one could argue that this would be a first indication of an intraday market that is liquid enough for generators to solve any looming schedule deviations they experience from inaccurate 24h-ahead forecasts. An empirical and more elaborate study by Hagemann and Weber (2013) though shows that the liquidity of the

German intraday market between 2010 and 2011 was relatively limited, which might not have improved towards 2015.

8.4.3. Imbalance netting and cross-border balancing impacts

As described in Chapter 6, Germany has been a member of the cross-border balancing imitative IGCC, which helps it to net imbalances with other countries. The imbalancing is in principle only restricted to cross-border transmission constraints. In 2012 Germany started the IGCC with Denmark and until 2015 also Netherlands, Belgium, Czech, Austria and Switzerland joined. In 2016 also France joined (Regelleistung, 2016). The connection of additional electricity systems to the IGCC, and thus Germany, increases the (potential) benefits. Fattler and Pellinger (2015) show that between the launch of the IGCC in 2011 and 2014 almost 3 TWh of positive and negative balancing power was saved. Ocker and Erhardt (2015) show that the total savings for Germany amounted to 25% of positive SR and 10% of negative SR, with a value of 12, 18 and 23 million euros respectively between 2011 and 2014. As France is a relatively big electricity system the savings might have significantly increased over 2015.

8.5. Historical activated secondary reserve distributions to forecast future values

8.5.1. Historical imbalance volumes as a proxy

As no quantified relation could be obtained to forecast the system imbalances or aFRR demand an alternative top-down approach is designed. Where the initial bottom-up approach aimed to forecast the system imbalances, and from there on the activated secondary reserves, the alternative top-down approach targets the system imbalance or activated aFRR directly. Because the relation between system imbalance and activated aFRR is not deterministic (although analysis showed the average yearly share of aFRR activation versus system imbalance was close to 80%) the bottom-up approach was applied to the activated aFRR directly. Figure 31 below shows the fitted distribution of activated aFRR for the period 2012-15 which is a Cauchy distribution. Cauchy distributions are represented in general by the following probability density function (PDF)

$$Cauchy(\sigma;\mu) \qquad PDF: \qquad f(x) = \frac{1}{\left(\pi\sigma\left(1+\left(\frac{x-\mu}{\sigma}\right)^2\right)\right)}$$

With:

σ = continuous scale parameter (σ > 0)

μ = continuous location parameter

The activated aFRR in all individual years between 2012-15 followed a Cauchy distribution. The aggregated distribution could be a first, rough approach to forecast future imbalances.

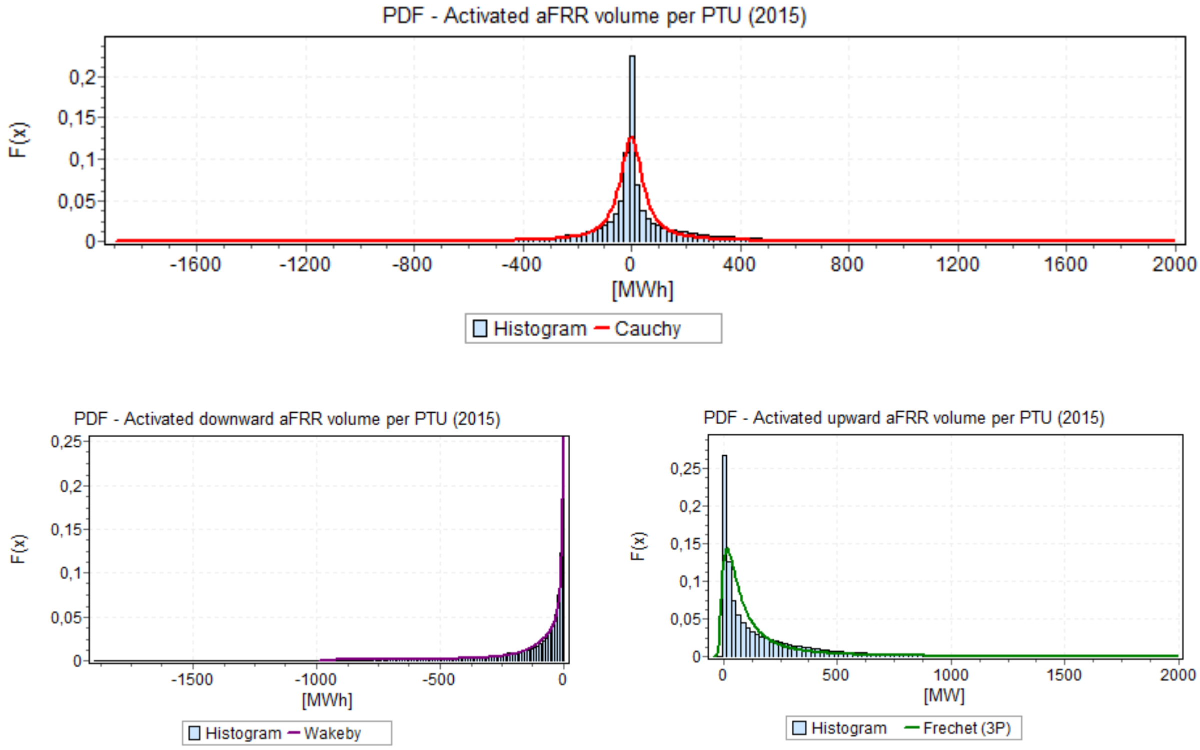

Figure 31 - Fitted probability density functions of activated aFRR in Germany for 2015. The optimal fits were chosen according to the Kolmogorov-Smirnoff test and the analysis was performed in Mathwave EasyFit Professional.

If samples are drawn from the distribution fitted over the time series of all activated aFRR volumes (both up and down) for future aFRR demand it could mean that the aFRR demand changes from a large positive to a large negative value (i.e. upward and downward regulation) in two subsequent PTUs. This is not realistic, as there will be probably be an autocorrelation between the demand for aFRR in two subsequent PTUs. When this effect is not modelled, it would also limit the deployment of any electricity storage technology on the aFRR market, as most technologies have ramp rates which won't allow them to be that flexible.

8.5.2. Incorporating increasing renewable penetration

Many studies have been devoted to the relation between the need for reserves and an increasing renewable penetration. In essence, the expected positive relation between forecast errors and system imbalances was also based on this relation. When using the activated aFRR distribution of the time series of 2015 more accurately to forecast future aFRR activations a scaling component might have to be incorporated.

Figure 32 shows the standard deviation of the Cauchy distribution of the aFRR demand in Germany for the years 2012-15 versus the wind and solar share of total production. Belgium, Spain and the Netherlands are also included to see how their ratios compare to Germany's. Because the standard deviation is the only scaling parameter in a Cauchy distribution it is used, and not, for instance, the total activated imbalance volume.

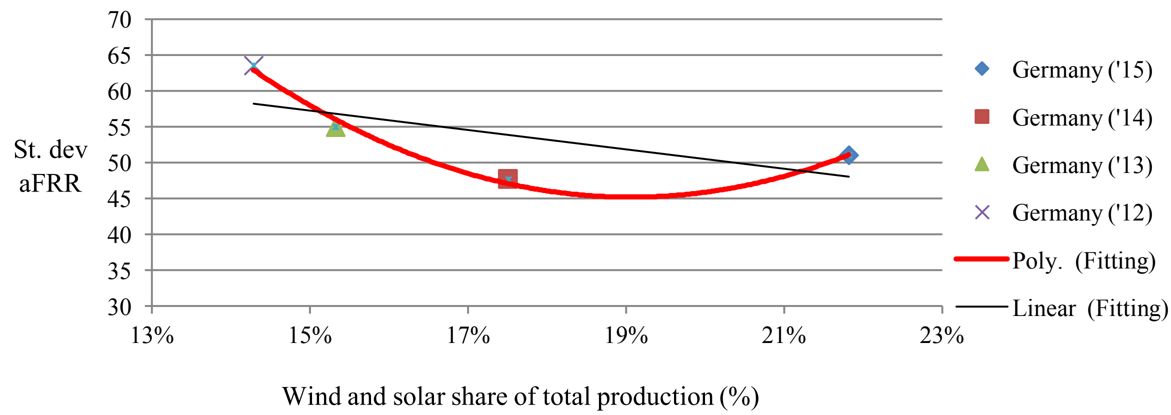

Figure 32 - Historical trends in the ratios between the size of historical aFRR distributions and the renewable penetration at that time, measured as wind and solar share of total production.

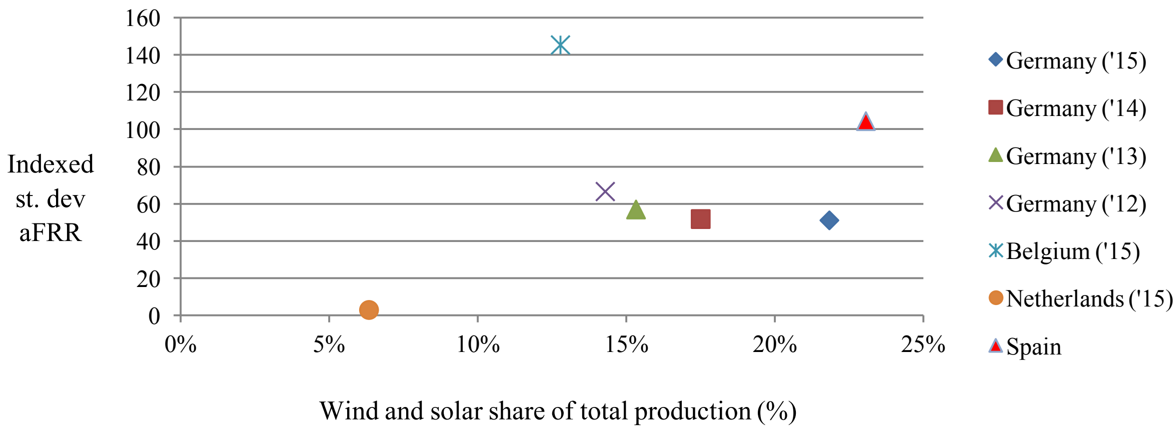

Figure 33 - Historical trends in the ratios between the size of historical aFRR distributions and the renewable penetration at that time, measured as wind and solar share of total production.

As no scaling approaches could be obtained from these intermediary results it was not further considered at this point.

8.5.2. Adding an autoregressive element

An autoregression analysis was therefore performed on the time series of 2015 of the activated aFRR. The results are presented in Table 16. Additional lags did not contribute significantly to an increased adjusted R-squared, so just a lag of one was considered for implementation.

Table 16 - Autoregression of the activated aFRR time series for 2015. The analysis was performed in GretL.

Independent variable	Coefficient	Adjusted R-squared
aFRR(t-1)	0,822	0,676

8.6. Final imbalance volume forecasting approach modelled in StRe@M

The result of an autoregression component and a distribution should result in the distribution of the time series of activated aFRR in 2015. In the StRe@M tool the future requested aFRR activations are thus modelled by the following function

$$V_{aFRR}(t) = 0{,}822V_{aFRR}(t-1) + \ random(Cauchy(9;\ 0))$$

With:
t = PTU
V_{aFRR} *= Volume of aFRR activated*

Any large enough set of samples from this function will approach a Cauchy distribution with standard deviation 51, corresponding to the historical data. The limitations of this result are described in Chapter 11.

8.7. Activated secondary reserve volume and price relation

8.7.1. Historical volume and price relation

Data was gathered for the year 2015 for the day-ahead market (DAM) spot price. A regression was performed on activated aFRR volumes, average activated aFRR prices and the DAM price in 2015. The average activated aFRR price was the dependent variable in this analysis, to see to what extend this price is determined by the DAM price and the aFRR volume. If this correlation can be identified it might be able to extend it for forecasting.

As shown in Chapter 6 the reimbursement for aFRR volume is determined via pay-as-bid. For the model the aFRR revenue is based on the average aFRR volume price, but depending on the operator's bidding strategy the potential revenue could be smaller or larger. No information about the spread in the aFRR activation prices per PTUs could be found, which would have provided some insights in the spread of the modelled potential revenue. The regression results are provided in Table 17.

Table 17 - Regression with aFRR price as dependent variable. The analysis was performed with GretL.

Factors	Coefficient	P-value
For upward aFRR prices		
Constant	51,728	0,000
Upward aFRR volume	0,033	0,000
DAM price	0,006	0,129 (not significant)
	Adjusted R-Squared	0,352
For downward aFRR prices		
Constant	0,572	0,049
Downward aFRR volume	0,062	0,000
DAM price	0,250	0,003
	Adjusted R-Squared	0,306

Figure 34 shows the scatter plot and regression results when only the aFRR reserve prices and volumes are considered.

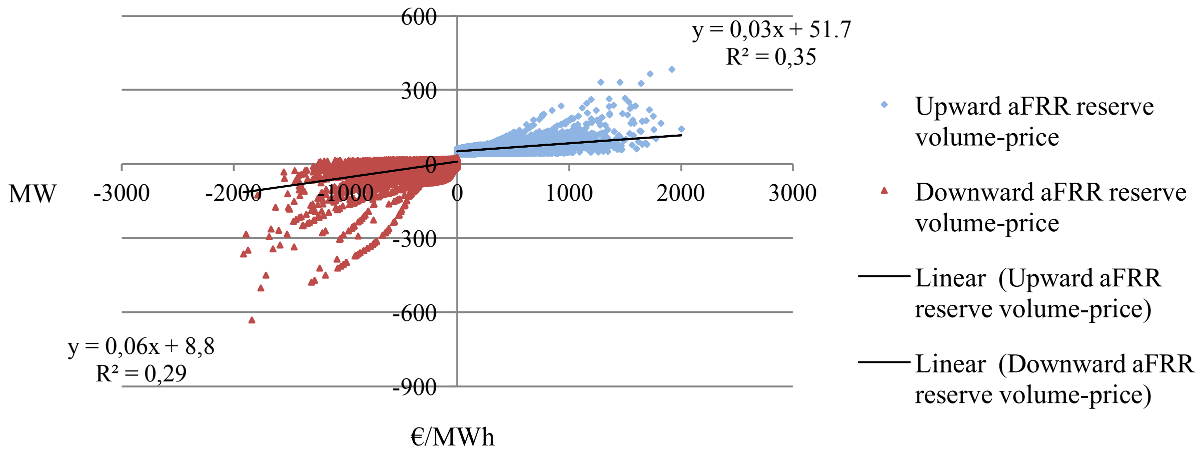

Figure 34 - German activated aFRR energy price versus volume per PTU in 2015.

8.7.2. Extension for forecasting

To preserve the historical stochastic characteristics, the following approach was used to find future positive imbalance prices for the forecasted aFRR positive volumes

$$P_{Up}(t) = 51{,}917 + 0{,}033V_{Up}(t) + random\ component$$

With:

t = PTU

P_{Up} = Price of upward activated aFRR [€/MWh]

V_{Up} = Volume of upward activated aFRR [€/MWh]

To determine the random component, the regression function is used on the historical data from 2015. For each PTU the residual of this analysis is determined, i.e. the difference between the actual historical recorded value and the value computed for that PTU using the regression function. In formula it is given as

$$Res_{up}(t) = \ P_{up}(t) - (51{,}917 + 0{,}033V_{up}(t))$$

With:

t = PTU

Res_{Up} = Residual of regression result and historical value [€/MWh]

P_{Up} = Price of upward activated aFRR [€/MWh]

V_{Up} = Volume of upward activated aFRR [€/MWh]

A distribution is fitted over the residuals resulting from all 2015 PTUs and the result was a Cauchy distribution for the upward price residuals and a Cauchy distribution for the downward price residuals, shown in Figures 35 and 36.

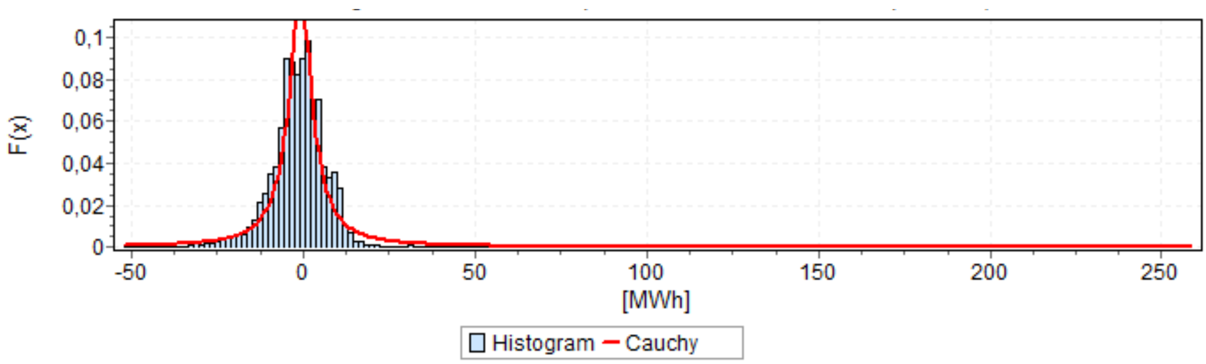

Figure 35 - Fitted distribution over the residuals from the regression analysis for upward activated aFRR energy prices in 2015. The optimal fits were chosen according to the Kolmogorov-Smirnoff test and the analysis was performed in Mathwave EasyFit Professional.

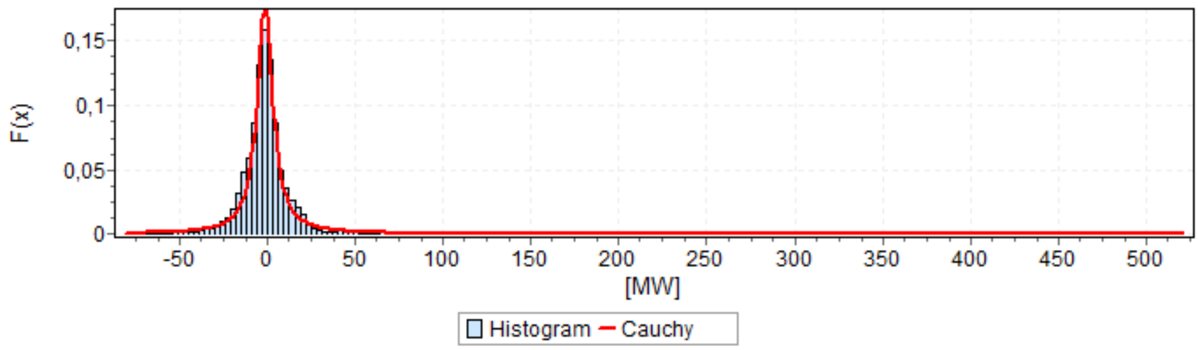

Figure 36 - Fitted distribution over the residuals from the regression analysis for downward activated aFRR energy prices in 2015. The optimal fits were chosen according to the Kolmogorov-Smirnoff test and the analysis was performed in Mathwave EasyFit Professional.

To match future prices with forecast activated aFRR volumes the following function was thus used in the model:

$$P_{up}(t) = 51{,}917 + 0{,}033V_{up}(t) + random(Cauchy(4{,}188;\ -0{,}666))$$

With:

t = PTU

P_{Up} *= Price of upward activated aFRR [€/MWh]*

V_{Up} = *Volume of upward activated aFRR [€/MWh]*

and

$$P_{down}(t) = 0.572 + 0,062V_{down}(t) + 0,250P_{DAM} + random(Cauchy(5,407; -0,949))$$

With:

$t = PTU$

P_{Down} = *Price of downward activated aFRR [€/MWh]*

V_{Down} = *Volume of downward activated aFRR [€/MWh]*

P_{DAM} = *DAM price [€/MWh]*

The limitations of this result are described in Chapter 11.

Chapter 9. Modelling and analysis of costs and revenues

9.1. Cost and revenue modelling

The cost and revenue module is the fourth module of the StRe@M tool and performs the last processing steps. It processes the spot market and secondary reserve market revenues that were computed in the Capacity Allocator module.

As was explained in Chapter 4 but will be explained here in more detail, the Capacity Allocator module compares a deterministic time series for the spot market prices with a stochastic time series for the demand and price of secondary reserve. The capacity allocator determines the optimal operation of an electricity storage facility on the spot and reserve market to maximize total revenue. It does so as follows. First it draws a large number of samples from the stochastic time series for the demand and price of secondary reserve. All these samples are then paired with the same deterministic time series for the spot market. The capacity allocator computes for all these combinations the optimal dispatch. The resulting revenues, which thus consist of a spot market and a secondary reserve market revenue component, all have an equal probability of occurring as the samples are drawn randomly. Ideally the number of samples is large (> 100) so the underlying stochastic distribution of the secondary reserve market time series is accurately represented.

The outputs of the Capacity Allocator module, and thus the input of the Cost and Revenue module, are a number of combinations of spot market and secondary reserve market revenues. The Cost and Revenue module, which is written in MS Excel (VBA) code loads these revenue samples, compares them with the appropriate costs and translates the revenue samples in an expected profit or a profit cumulative probability function. The next section will explain how the costs are modelled.

Figure 37 - Screenshot of the Cost and Revenue model in MS Excel (VBA).

9.2. Electricity storage technologies under study

Three electricity storage technologies and a gas turbine are modelled in the first version of StRe@M. Other electricity storage technologies, like the vanadium redox battery will be added in later versions. The gas turbine will also be modelled to see how this type of flexible conventional generation compares to the electricity storage technologies. The included technologies in the prototype are

- Fixed-speed PSH
- Variable-speed PSH
- Lithium-Ion battery

9.3. Fixed cost modelling

The costs are split in fixed costs and variable costs. The variable costs, which depend on the output level (the dispatch), are implemented in the PLEXOS model of the Capacity Allocator module. Besides computing revenues for the spot market and secondary reserve market the Capacity Allocator thus also computer the accompanying variable costs.

The fixed costs are modelled in the Cost and Revenue module’s Excel model and follow from a two-step calculation. First every (outgoing) cash flow to be incurred during the lifetime of the electricity storage facility modelled is discounted back to its present value (PV).

$$PV(i,N) = \sum_{t=0}^{N} \frac{C_t}{(1+i)^t}$$

With:

I = Discount rate [%]

C = Cash flow [€]

t = Time period

N = Number of periods to discount over

Then an ordinary annuity is calculated, a payment to be made at the end of each year during the entire lifetime of the facility. All the annuities combined equal the PV of all outgoing cash flows. This can directly be modelled with the following formula

$$PV_{Ordinary\ annuity} = A\left(\frac{1-(1+i)^{-n}}{i}\right)$$

With:

i = Discount rate [%]

A = Annuity payment [€]

N = Number of periods to discount over

The result of this calculation is that it does not matter in which year of the lifetime of an electricity storage facility it is modelled, as all cost are evenly spread out and paid for over the lifetime.

9.4. Modelled cost components and estimations

9.4.1. Cost estimations

The estimations for the cost components introduced below per electricity storage technology were established from DNV GL's expertise and network, which includes operators and manufacturers of storage technologies like ABB, Hatch and Vattenfall. In addition, the partners of eStorage, including General Electric/Alstom, contributed with their expertise on gas turbines and PHS technology. It is considered beyond the scope of this report to list all estimations and sources for all modelled cost components.

9.4.2. OPEX

The operational expenditures (OPEX) comprise operation and maintenance costs and any other costs to keep an electricity storage facility operational. For the modelling the OPEX was split in a variable and fixed part. As mentioned, the variable parts of the OPEX, which significantly changes with the method of operation of the facility, are accounted for in the PLEXOS model of the Capacity Allocator module.

The fixed parts of the OPEX, which includes labour costs and replacements or repair costs, are modelled in the Cost and Revenue module. For a real electricity storage facility, the fixed operation and maintenance costs will be incurred unevenly throughout the facility's lifetime. In the model a simplification is made as these costs are specified as a percentage of the investment cost, and are incurred each year and do not vary over the lifetime.

9.4.3. CAPEX

The capital expenditures (CAPEX) are split in investments costs and reinvestment costs. Investment costs comprise any costs associated with the construction of the electricity storage facility and getting it operational. This includes material and construction costs of the building as well as the costs or purchase of the electricity storage units. For use in the StRe@M tool no breakdown is made of the investment cost into these components, but rather a single investment cost per MWe of capacity is specified for each electricity storage technology. MWe, or megawatt electrical, entails an efficiency factor compared to just the nameplate capacity in MW and specifies how much power is effectively used to generate electricity. Energy generated by the difference between nameplate capacity and the electrical capacity is generally dissipated as heat.

The reinvestment costs are any costs needed to keep the storage facility operational. In reality a part of the reinvestment costs is incurred over the lifetime of the electricity storage facility. For the modelling the costs were assumed to be incurred after a specified number of years, which the annuity calculation then translated in an annual expense.

9.4.4. Fixed cost component overview

Table 18 provides an overview of the modelled electricity storage technologies and the facility configurations. All cost components are specified with a base value as well as a low and high value to model a risk appetite.

Table 18 – Overview of the fixed cost components and parameters in Cost and Revenue module

Technology	Unit	Gas Turbine (based on a General Electric LMP6000 turbine)			Lithium-Ion Battery system			Vanadium Redox battery system			Fixed-speed PSH			Variable-speed PHS		
Net generating capacity	MWe	51			1			1			252			255,5		
		Low	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Investment costs																
Specific investment cost	€/kWe	826	950	1.188	782	1.384	2.013	996	1.053	1.284	828	1.274	1.911	870	1.338	2.007
Reinvestment costs																
Construction time	year	0,75	1	1,5	0,25	0,5	1	0,25	0,5	1	4	5	6	4	5	6
Lifetime	year	20	25	30	20	25	30	20	25	30	40	50	60	40	50	60
Time till reinvestment cost needed	year	10	15	20	3	5	7	6	8	10	60	60	60	60	60	60
Reinvestment cost	% of initial investment	10	15	20	15	29	43	12	14	20	0	0	0	0	0	0
Fixed operation and maintenance costs	%/y of initial investment	2	4	6	2	2,5	3	2	2,77	3	0,25	0,5	1	0,25	0,5	1
WACC (real, before tax)	%	4	5	6	4	5	6	3	4	6	4	5	6	4	5	6

Chapter 10. First modelling results

After completion of the Imbalance Forecaster module and Cost and Revenue module, and combining those with the Future Dispatch and Capacity Allocator module, the StRe@M prototype is finished. This section provides the first results of the StRe@M prototype and should thus be used with caution.

10.1. Modelling outputs

The modelling results of the StRe@M tool can be visualised by looking at the activity on the aFRR and spot market and the realized revenues for the electricity storage facility under investigation. Upon finalization of this report a German future dispatch scenario for 2020 with a generation mix with an 80% RES share was available for processing, though also there some improvements are required of which the most important is a more accurate representation of the spot price volatility. The simulation duration of a scenario for one year and 100 samples was more than 12 hours. The results shown below are therefore based on the simulation of one month, namely February 2020, as the time scope did not allow to run additional samples.

It should also be noted that the three technologies presented are all modelled for the same scenarios; the eight samples for spot and reserve volume and price time series are equal for all modelling runs.

10.2. VS-PSH results

The VS-PHS modelled was a facility with a capacity of 255,5 MWe and the results of the first StRe@M runs are presented below. Figure 38 shows the dispatch of one of the samples for the first week of February. The actual generation of the facility (yellow bars in Figure 38) is determined by the generation according to sales on the spot market, minus any downward generation provided to the secondary reserve market, and plus any upward generation provided to the secondary reserve market.

The dispatch shows that the facility is active in quite some PTUs and that the facility provides downward regulation at quite some PTUs (the blue areas; when the actual generation is lower than the generation needed to provide spot market obligations).

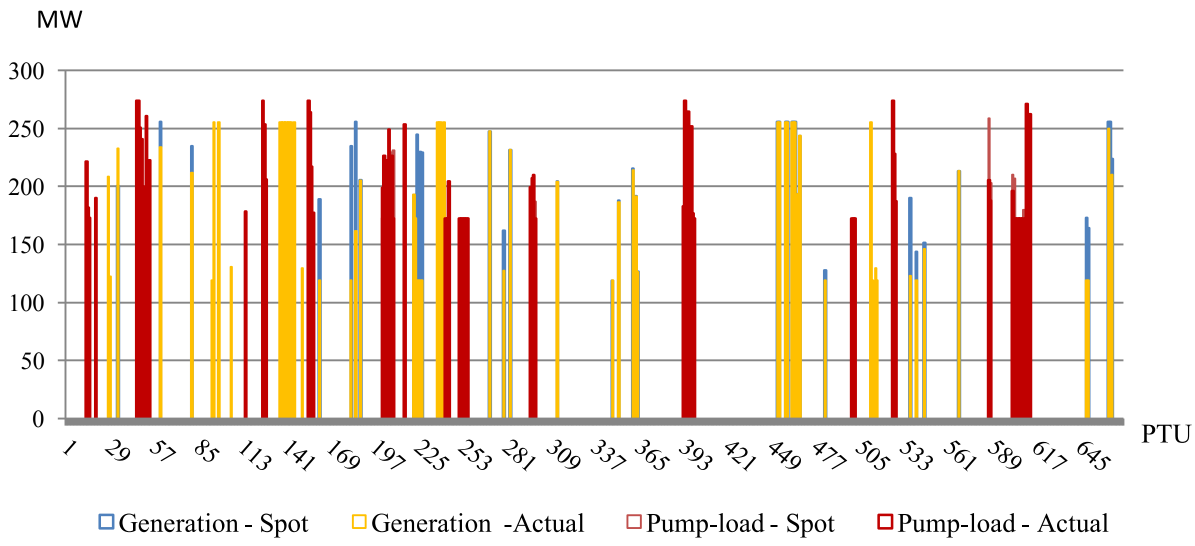

Figure 38 - VS-PSH first dispatch results for sample 1 for February 1-7 2020.

Table 19 - VS-PSH first cost and revenue analysis results for sample 1 for February 1-7 2020.

Samples	**One**	**Two**	**Three**	**Four**	**Five**	**Six**	**Seven**	**Eight**
Total generation [GWh]	53	61	60	59	53	45	57	59
Total pumping [GWh]	61	71	69	68	62	52	65	68
Total revenue [k€]	1.180	1.262	1.390	1.172	1.166	903	1.264	1.268
Total variable costs [k€] (from the Capacity Allocator module)	620	664	695	648	643	573	626	645
Total fixed costs [k€] (from the Cost and Revenue module)	379	379	379	379	379	379	379	379
Total costs [k€]	999	1.043	1.074	1.027	1.022	952	1.025	1.024
Total net profit [k€]	181	219	316	145	144	-49	239	244

10.3. FS-PSH results

The FS-PSH modelled was a facility with a capacity of 255,5 MWe. The results show that the FS-PSH facility is much less active than the VS-PSH facility. This is probably because of the additional flexibility the VS-PSH plant has over the VS-PSH. Despite the lower revenues compared to VS-PSH the costs of a FS-PSH are quite similar. This results in a net loss in five out of eight samples.

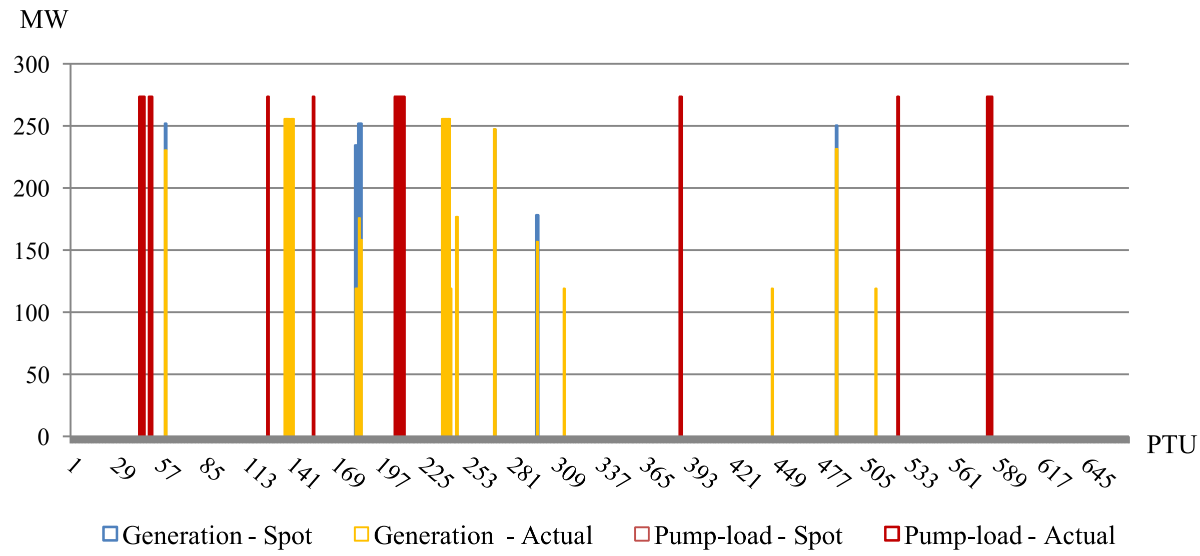

Figure 39 - FS-PSH first dispatch results for sample 1 for February 1-7 2020.

Table 20 – FS-PSH first cost and revenue analysis results for sample 1 for February 1-7 2020.

Samples	**One**	**Two**	**Three**	**Four**	**Five**	**Six**	**Seven**	**Eight**
Total generation [GWh]	25	28	27	28	22	18	28	29
Total pumping [GWh]	29	33	32	33	27	21	32	35
Total revenue [k€]	648	612	740	609	578	355	620	683
Total variable costs [k€] (from the Capacity Allocator module)	286	283	319	281	279	239	290	305
Total fixed costs [k€] (from the Cost and Revenue module)	349	349	349	349	349	349	349	349
Total costs [k€]	635	632	668	630	628	588	639	654
Total net profit [k€]	13	-20	72	-21	-50	-233	-19	29

10.4. Lithium-ion battery results

The lithium-ion battery modelled was a facility with a total capacity of 10 MW. It shows very high profits in all samples.

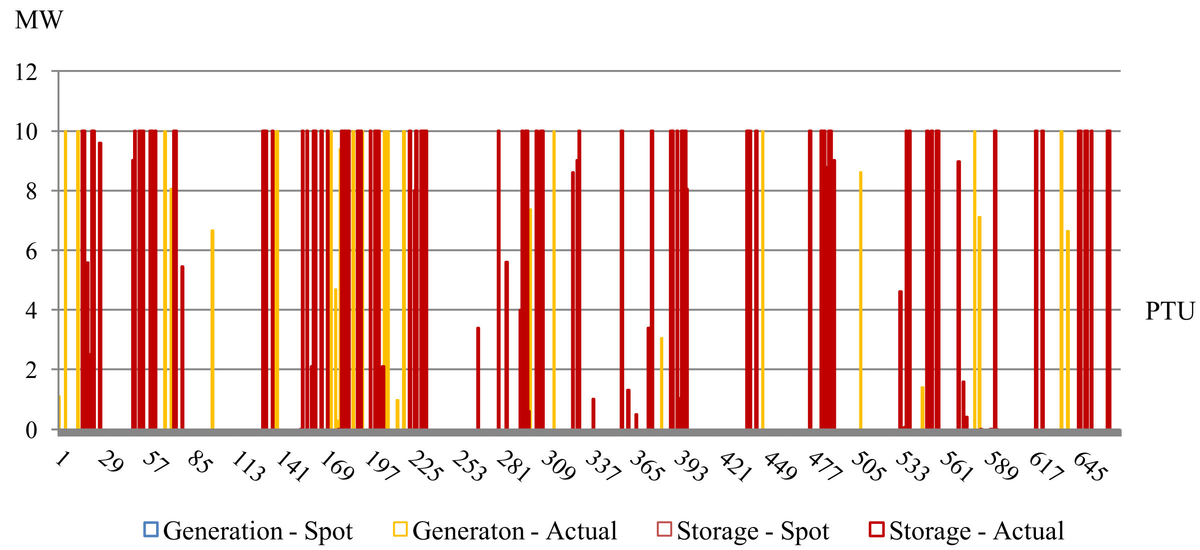

Figure 40 – First lithium-ion battery dispatch results for sample 1 for February 1-7 2020.

Table 21 – Lithium-ion battery first cost and revenue analysis results for sample 1 for February 1-7 2020.

Samples	**One**	**Two**	**Three**	**Four**	**Five**	**Six**	**Seven**	**Eight**
Total generation [GWh]	1,1	1,2	0,9	1,1	1,0	1,3	0,9	1,0
Total pumping [GWh]	3,6	3,8	3,3	3,6	3,3	3,8	3,1	3,3
Total revenue [k€]	73,4	68,4	66,7	67,3	71,5	68,0	62,5	57,6
Total variable costs [k€] (from the Capacity Allocator module)	2,0	2,9	6,8	1,5	1,2	1,9	3,6	1,8
Total fixed costs [k€] (from the Cost and Revenue module)	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2
Total costs [k€]	5,2	6,1	10,0	4,7	4,4	1,3	6,8	5,0
Total net profit [k€]	68,2	62,3	56,7	62,6	67,1	66,7	55,7	52,6

Chapter 11. Conclusions and future work

11.1. Conclusions

This thesis study has contributed to the prototype of the StRe@M model; a model that can be used to stochastically forecast future profits of electricity storage facilities in future scenarios of the German electricity grid. This thesis study particularly focused on generating time series for secondary reserve demand, which can be processed into a potential reserve revenue stream. The analysis is supplied with a qualitative analysis of the German electric power industry, its markets and regulatory framework.

The deliverables include this report and multiple proprietary MS Excel models to forecast future secondary reserve volumes and prices in Germany and to determine the profit of operating an electricity storage facility on the spot market and secondary reserve market.

The conclusions of this thesis study will be presented by answering the research questions formulated in Section 4.3, starting with the main research question.

- *What is the economic feasibility of electricity storage technologies in future scenarios for the German electricity grid from a price-taking investor's perspective?*

The economic feasibility of three different energy storage technologies was assessed by comparing costs with revenues from the spot market and secondary reserve market. The first scenario modelled was a future German electricity grid in February 2020 with an 80% RES share of installed electricity generation capacity.

The modelled technologies were FS-PSH, VS-PSH and lithium-ion battery. The initial modelling results of the different electricity storage technologies seemed economically feasible as they showed positive profits for all drawn samples, shown in Table 22. As the model designed was a prototype, the results of the modelling should be used with caution though, and the main limitations and assumptions (provided later in this Chapter) should be kept in mind.

Table 22 – Estimated profits of three different electricity storage technologies based on the first modelling results of the StRe@M model. The scenario modelled is the German electricity grid, in 2020, with an 80% RES share.

(all values in k€) **Samples**	**One**	**Two**	**Three**	**Four**	**Five**	**Six**	**Seven**	**Eight**
FS-PSH (255,5 MW facility)	13	-20	72	-21	-50	-233	-19	29
VS-PSH (255,5 MW facility)	181	219	316	145	144	-49	239	244
Lithium-ion battery (10MW facility)	73,4	68,4	66,7	67,3	71,5	68,0	62,5	57,6

- *How does the regulatory framework in Germany define electricity storage and what are the implications on levies and support mechanisms?*

There is no clear-cut regulatory definition for electricity storage in the German regulatory framework. The definition of "storage facilities" in the EnWG is aimed at gas storage facilities and electricity storage facilities are referred to with this definition in the EEG. Following a German court appeal in 2009 electricity storage facilities are treated as end consumers during times they are storing electricity and as generators when they are feeding energy back to the grid. The implications on levies and support mechanisms are therefore also not perfectly clear for interpretation but the most important conclusions are:

(1) PSH facilities can benefit from FiTs as they are acknowledged as renewable sources. Regarding electricity storage, operators of renewable energy installations can apply for FiTs also if the electricity has been stored temporarily before being supplied to the grid. In this case the tariffs apply that would have been given to a renewable energy source supplying energy directly to the grid.

(2) Electricity storage facilities are exempt from the EEG levy if the stored electricity is exclusively fed back into the grid from which it is originally drawn. PSH is furthermore exempt from the transmission charge, if certain specific conditions are met relating to capacity and construction and commission times.

(3) For the other levies and fees, including concession fees, the CHP levy, the StromNEV levy, the offshore levy and the Ablav levy no exemptions or reductions for electricity storage technologies could be identified.

- *What are the reserve market opportunities for electricity storage technologies in the German electricity market today?*

A qualitative study has first identified the three reserve markets in Germany, namely the primary reserve market (FCR), the secondary reserve market (aFRR) and the minute reserve market (mFRR), and has mapped their characteristics. Participation in these reserve markets is basically open to any BRP, as long as transmission and generation activities remain unbundled. There are some technical requirements though that could pose a barrier for operators of electricity storage facilities, of which the most important are:

(1) The minimum bid sizes of 5 MW for secondary and minute reserve could form an important limitation for some electricity storage technologies. Though facilities based on PSH are large, facilities based on battery technologies might not reach this threshold. Portfolio-based bidding is allowed though, meaning that bidders can aggregate individual bids from isolated plants into a larger bid. If the BRPs' portfolios allow it the minimum bid sizes can then probably be achieved.
(2) Minimum response times and ramp rates, which vary per reserve product, are in place but fall well within the technical limitations of most electricity storage technologies.
(3) The requirement for providers of primary reserves to guarantee a 100% availability could be a problem for most electricity storage technologies, depending on the time frame considered, as the resource can be uncontrollable and intermittent. For most potential activation durations, varying between 4 and 12 hours the availability can be secured by adequate storage sizes.

- *What are the main drivers that currently determine imbalance volumes in the German grid?*

Through a literature study the main factors determining system imbalance volumes were identified as forecast errors from load, solar generation and both onshore and offshore wind generation. This study tried to identify a quantified relation between these drivers and system imbalances but could not identify one. A qualitative assessment of other factors impacting the system imbalance in Germany was then performed, as a quantitative assessment was beyond the (time) scope of this project. These factors included the IGCC, a cross-border balancing corporation Germany is a member of, as well as the liquidity of the intraday market. Especially the IGCC seems to have contributed in a large extend to the formation, and mitigating in this sense, of system imbalances, as was showed by the 'German reserve paradox' in Chapter 6.

11.2. Assumptions and limitations of model and analysis

Modelling a complex system like an electricity system's imbalance mechanism requires making simplifications and assumptions to obtain an applicable model. The main assumptions and limitations of the model are the following:

1. **The functioning of the secondary reserve market in Germany in 2020 will remain as it is today**. The proposed modelling structure is based on the structure and functioning of the secondary reserve market as it is in place in Germany today. Changes in the market can result in different revenue assessments and require a revision of the StRe@M functioning.
2. **Only upward or downward secondary reserve demand within a single PTU is modelled**. The function designed to represent future demand for secondary reserve can result in both positive and negative values. When the values are negative, they are assigned to downward regulation. When they are positive, they are assigned to upward regulation. This means that within a single PTU not both upward and downward regulation can be demanded, which could happen in reality and sometimes does in Germany. This assumption was made though because the average ratio between upward and downward regulation within a PTU was very low, meaning that usually the demand for either one of the two dominated and was much larger than the other.
3. **No scaling for an increasing renewable penetration** was implemented in the first version of StRe@M. A stochastic function was developed that can be used to forecast future secondary reserve demand which preserved the stochastic properties of the probability density function of the activated reserves in 2015.
4. **No capacity mechanisms are modelled in 2020**. Chapter 7 has shown that the German regulators are looking at capacity mechanisms but it is unlikely they will be implemented in the short term, i.e. a few years.

11.3. Recommendations for future work

The recommendations for future work presented below relate to the modelling research performed in this study, i.e. the design of the Imbalance Forecasting and Cost and Revenue module.

Recommendations for future work on the Imbalance Forecaster module are:

- **Sensitivity analysis of model**. It did not fit in the time scope of this project to perform a thorough sensitivity analysis of the first StRe@M results. It would be very interesting to see though how the economic feasibility changes with the scaling of the standard deviation of the function used to forecast future secondary reserve demand. A scenario analysis is very suited for this. Testing the monetary outcomes of the model will be difficult as there are no benchmarking studies available for the value of electricity storage from an investor's perspective in future scenarios. Comparing historical profits with industry participants, if they can be found willing, might providing useful insights and reflection.

- **Expansion of the bottom-up approach for the forecasting of imbalances**. This study has applied a bottom-up approach using forecast errors for wind and solar generation and load to forecast system imbalances. This approach did not result in a workable method for forecasting. If more effects than just the forecast errors could be included in a bottom-up approach results might improve. A specifically interesting area would be the impact the IGCC has had and will have on the demand for secondary reserve.
- **Further work into the identification of a scaling component for relating reserve demand to renewable penetration**. This study investigated specifically the relation between the standard deviation of the distributions of activated reserve between 2012 and 2015 and several parameters relating to renewable penetration in those years. No workable scaling relation could be identified between the two. As stated in Chapter 8, this might be because the German reserve market has been undergoing several changes during these years, including increased cross-border balancing. Interesting areas for future work might be performing the same analysis for the Spanish or Danish electricity system, which also have relatively high penetrations of renewables. In addition, Denmark is also a member of the IGCC and the analysis might reveal the impact the IGCC has had on the reserve demand in Germany.
- **Advancing the volume-price computation**. In the first version of StRe@M the volume-price relation is based on a regression analysis of historical time series from 2015. The result was a function with a stochastic component which was applied on all volume levels. If this function would be split and a revised, scaled, random component would be used for different volume levels the resulting price levels will become more realistic. The random component that is applied in the current version can result in a very high value, though the probability is small.

Recommendations for future work on the Cost and Revenue module are:

- **Incorporation of levies and support mechanisms when StRe@M results become robust enough**. The first model of StRe@M did not include levies and support mechanisms. When a certain level of certainty can be obtained, it might be worth including the financial impacts of levies and support mechanisms on the expected profit.

11.4. Reflection

11.4.1. Social relevance

The ongoing transformation of electricity systems of becoming more sustainable and reducing the environmental footprint will in almost all systems ultimately be achieved through a greater penetration of renewable generation. The challenges for electricity grids that come with intermittent generation will thus also increase in size, and a possible solution lies in additional grid flexibility. As practically all electricity storage technologies have the potential of contributing to grid flexibility their deployments in the grid are being explored and tested intensively by regulators and utilities. Many studies have therefore been commissioned investigating the potential value of electricity storage from a system's perspective.

In the liberalized markets the potential deployment of electricity storage technologies will, at least partially, be left to the market though. Nonetheless there is a lack of research approaching the value from an investor's perspective. Private investors are therefore looking for business cases and analyses of the economic feasibility of electricity storage facilities to guide and help with investment decisions. The contribution of this thesis study to the design of the first version of the StRe@M model contributes to mitigating this investment uncertainty.

11.4.2. Scientific relevance

System imbalances and reserve demand are the result of a complex electricity system and their analyses does not lend itself to simple models. No studies could be identified that have achieved significant results on forecasting future system imbalances and demands multiple years ahead. This thesis study has contributed to the understanding and mapping of the limitations of forecasting future reserve demand and its intrinsic challenges. It has showed that a bottom-up approach using forecast errors could not be used in the German electric power industry and has instead presented a pragmatic solution which, with enough sensitivity analyses, could be used in a scenario modelling approach to forecast future secondary reserve demand and prices. Furthermore, a cost-modelling approach was designed that allows to succinctly though representatively model the costs of deploying electricity storage facilities in future grid scenarios.

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Annex A – Electric power industry economic principles

Market clearing, merit order and unit dispatch are three important terms in electric power industries which are explained here succinctly.

A.1. Market clearing

Wholesale bids and offers in an electricity market are generally received and processed by a market operator. A computer algorithm is used for clearing the market, which refers to the matching of demand (bids) and supply (offers). The result is a market clearing price and volume; the point at which the price that demand is willing to pay for electricity is equal to the price that supply will take for providing it. The common economic term is market equilibrium. The market clearing process is illustrated in Figure 41. The electric power industry does not have a continuous supply (blue) or demand (red) curve but rather a staircase one as the trading happens in blocks of power instead of e.g. per MW in order to decrease complexity and the number of transactions. The next section elucidates the merit order process which is how the supply curve is constructed.

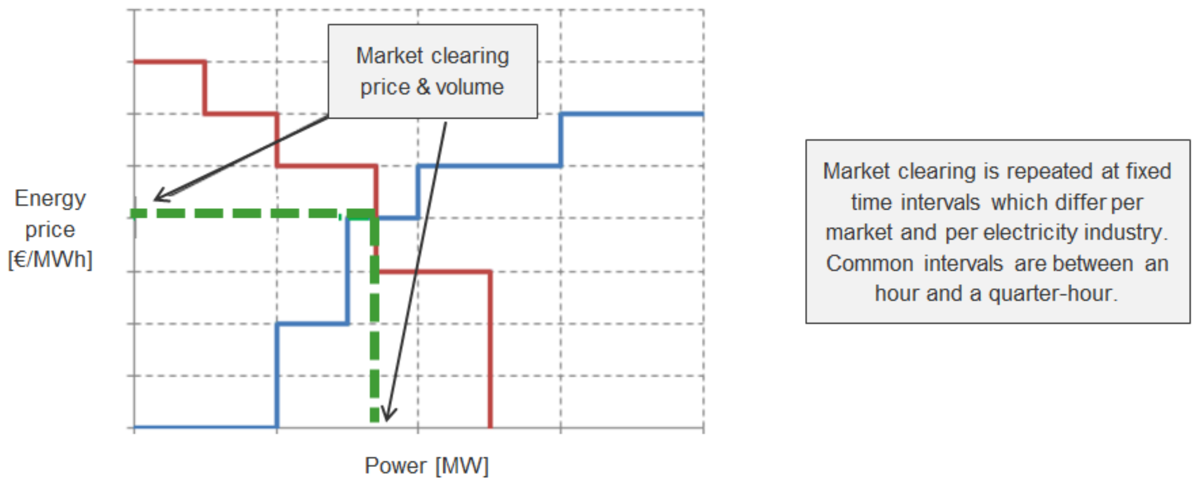

Figure 41 - A simplification of the market clearing process in wholesale electricity markets.

A.2. Merit order

The merit order refers to the ranking of available offers of electricity generation based on ascending order of supply price per generation block. This will be definition result in an upward sloping staircase-shaped supply curve. In most liquid electricity markets companies' supply bids closely reflect their short-run marginal costs of production (Pikk and Viiding 2013). The market clearing price is therefore generally set by the marginal cost of the last generator needed to cover all demand. Figure X on the next page illustrates the process. In this simplified there is one supply block of wind, solar and water generation, which accepts the lowest payment for supply price and is therefore stacked first against the vertical price axis. As the short-run marginal cost of production is practically zero for most renewables, they usually 'come first in the merit order'. Next is a supply block of nuclear generation, followed by four blocks of supply from lignite coal (which might be from four different generation companies), after which the supply curve is completed by adding all supply blocks. Figure 42 also shows that when the cheap supply increases, which can be represented by the stretching of bidding blocks or adding additional ones, it pushes more expensive supply blocks out of the market when demand is unchanged. The result is a lower market clearing price.

A.3. Unit dispatch

The unit or generation dispatch refers to the production schedule of a generating plant and specifies when to generate how much. When a generator bids in one of the electricity markets for a certain delivery time, and his offer is cleared in the market, which means that his supply block is to the left of the cleared power demand in Figure 42, he is obliged to deliver this power at the delivery time. The unit dispatch of a generating plant is thus determined by the outcomes market clearing process, which he can influence by changing his own bids. In most electricity industries the delivery obligations can be traded on other electricity markets so that a generator can adjust his unit or generation dispatch if he wishes, as long as he can find buyers.

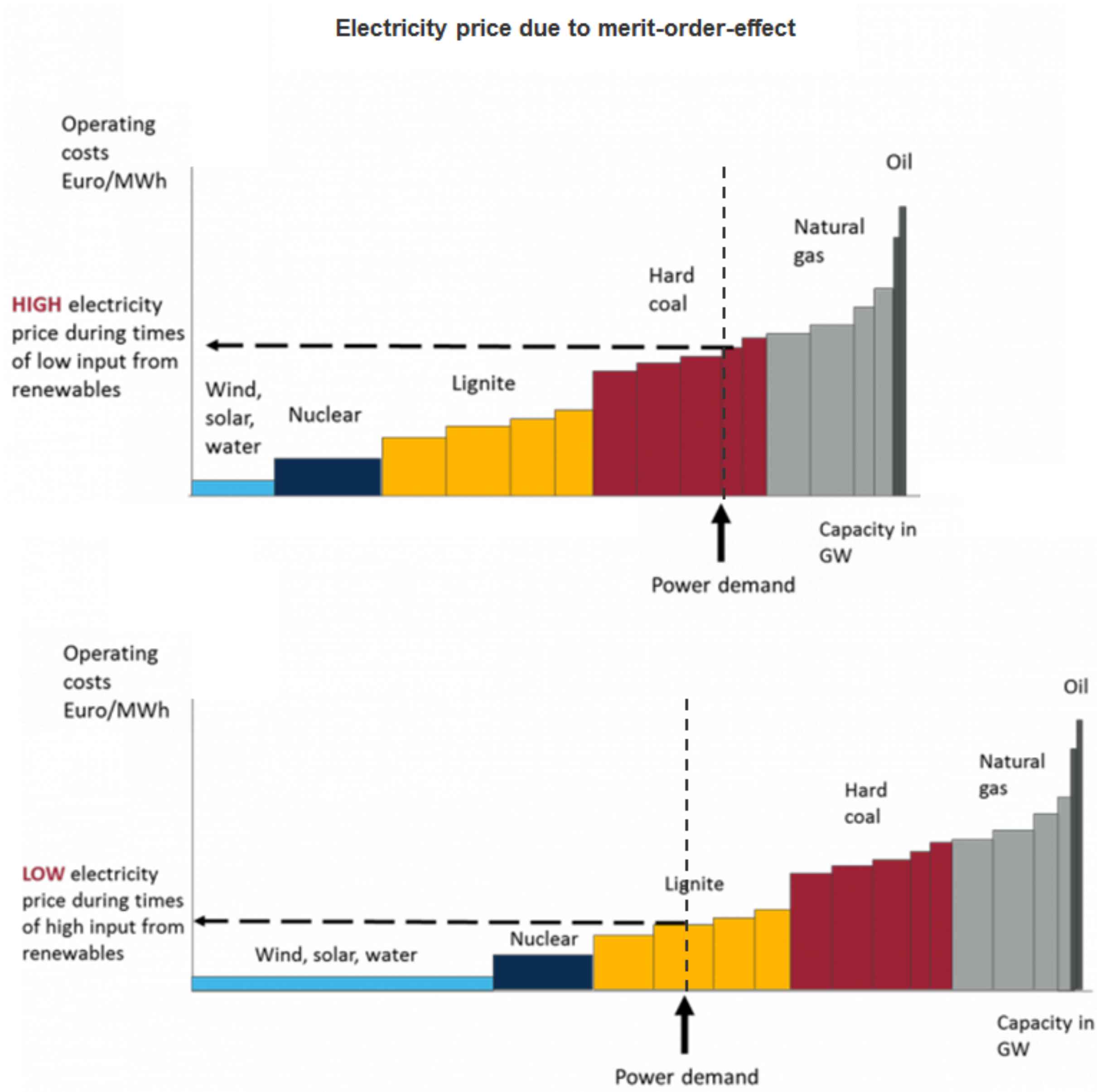

Figure 42 - Graphical illustration of the merit –order-effect. Source: CleanEnergyWire.org

Annex B – German actual production and forecast data

The data gathering and data set construction and processing for the German actual and forecasted production in 2015 are described here.

B.1. Data gathering

The historical time series data for load and solar and wind production in Germany was gathered from various data sources. By law the German TSOs must publish data on forecasts and actual generation which they do on their respective websites. In February 2016 the daily production and forecast data was usually available online on the same day. The data is updated or supplemented later on in case the TSOs find errors or additional measurements become available. Data for the TSO control regions is also available on the ENTSO-E (European Network for Transmission Operators for Electricity) Transparency platform. This entity represents 41 European TSOs and promotes closer cooperation among TSOs to make their services more efficient. Table 23 provides an overview of the data sources.

Table 23 - Overview of data sources used for German production forecast and actual production data.

Data	**Region**	**Provider**	**Website**
Day-ahead production forecasts and Actual productions	Per control area and aggregated German total	ENTSO-E	https://transparency.entsoe.eu/
Day-ahead production forecasts and Actual productions	50Hertz control area	50Hertz	http://www.50hertz.com/de/
Day-ahead production forecasts and Actual productions	TenneT control area	TenneT	http://www.tennet.eu/de/home.html
Day-ahead production forecasts and Actual productions	Amprion control area	Amprion	http://www.amprion.net/
Day-ahead production forecasts and Actual productions	TransnetBW control area	TransnetBW	https://www.transnetbw.de/de

B.2. Data set construction

Inconsistencies were encountered between data on TSO websites and that on the ENTSO-E platform. This could be due to the delay in updating of data. In addition, the available data on both platforms is sometimes of poor quality as quite some PTUs contained no data or very abrupt changes in the time series (which must come from incorrect measurements or data processing). In addition, the data sources used different formats and frameworks to structure the data making it difficult to compare data without lengthy processing first. Table 24 provides an overview of the data set.

B.3. Data processing

Data for the actual German onshore wind production, obtained from ENTSO-E, was only provided as a single aggregated value for Germany, Austria and Luxembourg. As Austria and Luxembourg do have wind production, the value's share of Germany had to be determined. To obtain the actual onshore wind production of Germany from the combined Germany-Austria-Luxembourg-value the PTU quantities were multiplied by the German share of the total onshore wind production of the three countries in 2015. As the respective productions were 55,97 TWh (Germany), 3,03 TWh (Austria) and 0,08 TWh (Luxembourg) the adjustment factor was 0,95 (EWEA website).

The data for the onshore wind production forecasts was also obtained from ENTSO-E and was only available for the four German TSOs. Hence, the total German production forecasts were obtained by summing the respective TSO values.

Table 24 - Data set components, sources and download information for the German actual and forecasted production data set.

Data			Sources	Processing	Latest download date
Intermittent generation and load Forecast errors	**Onshore wind**	Day-ahead production forecast	ENTSO-E (data for the TSO control areas)	To obtain the German total from the data per TSO the values were summed	09-05-2016
		Actual production	ENTSO-E (data for the Germany-Austria-Luxembourg region)	To extract the German total all production values were scaled according to the ratio between the countries' 2015 onshore wind productions	18-04-2016
	Offshore wind	Day-ahead production forecast	ENTSO-E (data for the TSO control areas)	To obtain the German total from the data per TSO the values was summed	09-05-2016
		Actual production	ENTSO-E (data for the Germany-Austria-Luxembourg region)	To extract the German total no processing was required as Austria and Luxembourg have no offshore wind capacity and hence the whole value was attributed to Germany	18-04-2016
	Solar	Day-ahead production forecast	Amprion	To obtain the German total the TSO-values were summed	07-04-2016
			50Hertz		07-04-2016
			TenneT		07-04-2016
			TransnetBW		11-04-2016
		Actual production	Amprion	To obtain the German total the TSO-values were summed	07-04-2016
			50Hertz		07-04-2016
			TenneT		07-04-2016
			TransnetBW		11-04-2016
	Load	Day-ahead load forecast	Amprion	To obtain the German total the TSO-values were summed	07-04-2016
			50Hertz		07-04-2016
			TenneT		13-04-2016
			TransnetBW		11-04-2016
		Actual load	Amprion	To obtain the German total the TSO-values were summed	07-04-2016
			50Hertz		07-04-2016
			TenneT		13-04-2016
			TransnetBW		11-04-2016

Annex C – German reserve and imbalance data

The data gathering and data set construction for the German reserve and imbalance data in 2015 are described here.

C.1. Data gathering

The historical series data for system imbalance, also called control area balance, and activated reserve volumes in Germany were gathered from two data sources, Regelleistung and the ENTSO-E Transparency Platform. Table 25 provides an overview of the data sources.

Table 25 - Overview of data sources used for German reserve and imbalance data.

Data	Region	Provider	Website
Imbalance volumes and prices and Activated secondary reserve volumes and prices	Per control area and aggregated German total	Regelleistung	https://www.regelleistung.net/ext/
Imbalance volumes and prices and Activated secondary reserve volumes and prices	Per control area and aggregated German total	ENTSO-E	https://transparency.entsoe.eu/

C.2. Data set construction

Table 26 summarizes the data set construction.

Table 26 - Data set components, sources and download information for the German reserve and imbalance data.

<table>
<tr><th colspan="6">Data set construction for German reserve and imbalance data</th></tr>
<tr><th colspan="2">Data</th><th>German parameter name</th><th>Source</th><th>Processing</th><th>Latest download date</th></tr>
<tr><td rowspan="4">Balancing</td><td rowspan="2">Control area balance</td><td>rzSaldo</td><td>Regelleistung</td><td rowspan="2">No processing required</td><td rowspan="2">09-03-2016</td></tr>
<tr><td>System imbalance</td><td>ENTSO-E</td></tr>
<tr><td rowspan="2">Activated secondary reserve (price and volume)</td><td>SRL</td><td>Regelleistung</td><td rowspan="2">No processing required</td><td rowspan="2">09-03-2016</td></tr>
<tr><td>Activated aFRR</td><td>ENTSO-E</td></tr>
</table>

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