Frequency Control in the European Power System Considering the Organisational Structure and Division of Responsibilities

Author(s):
Scherer, Marc

Publication Date:
2016

Permanent Link:
https://doi.org/10.3929/ethz-a-010692129

DISS. ETH NO. 23490

Frequency Control in the European Power System Considering the Organisational Structure and Division of Responsibilities

A thesis submitted to attain the degree of
DOCTOR OF SCIENCES of ETH ZURICH
(Dr. sc. ETH Zurich)

presented by

MARC SCHERER

MSc ETH EEIT
citizen of
Switzerland

accepted on the recommendation of
Prof. Dr. Göran Andersson, examiner
Prof. Dr. Kjetil Uhlen, co-examiner

2016

ETH Zurich
Power Systems Laboratory
Physikstrasse 3
8092 Zurich, Switzerland

DOI: 10.3929/ethz-a-010692129 (e-collection)
ISBN: 978-3-906327-43-3 (paperback)

Abstract

One of the core responsibilities of a transmission system operator is real-time control of mismatches between scheduled production and actual consumption of electric power, i.e. frequency control. Since the liberalisation of electricity markets and the increase of decentralised intermittent generation, the Continental European power system has been exposed to high and persisting frequency deviations.

This thesis investigates technical and organisational shortcomings of the existing frequency control framework in Continental Europe. The objective is to contribute to future concepts of frequency control that ensure an efficient and high frequency quality in the interconnected power system. Historical data are statistically analysed and used for time-sequential Monte Carlo simulations which enable the investigation of the current frequency control structure as well as frequency control coupling processes in future demand and production portfolios.

Although the domination of hourly imbalance periods and respective hourly products imposes a highly predictable operational pattern, market-induced imbalances have a severe impact on frequency quality. In this context, the benefits of harmonised ramping requirements and the reduction of the imbalance period are discussed. The current frequency control setup can be gradually centralised across Europe. Imbalance and reserve sharing can be practically implemented, and transfer capacities can be managed. Imbalance sharing does not require additional harmonisation of active power reserve processes and products. Reserve sharing, on the contrary, can only be managed on a non-discriminatory and fair basis if the active power reserve dimensioning as well as the activation rules are harmonised to grant a comparable performance.

The findings imply that system operators and national regulatory authorities should focus more closely on the dependency between schedule-based operation and market activity as well as on local active power reserves and cross-border frequency control processes.

Kurzfassung

Eine der Kernverantwortlichkeiten eines Übertragungsnetzbetreibers ist der Ausgleich zwischen Stromverbrauch und -erzeugung, d.h. die Netzregelung. Seit der Liberalisierung der Elektrizitätsmärkte und dem Anstieg dezentraler und variabler Stromerzeugung ist das kontinentaleuropäische Stromnetz hohen und anhaltenden Frequenzabweichungen ausgesetzt.

Diese Arbeit diskutiert technische und organisatorische Schwächen aktueller Netzregelstrukturen in Kontinentaleuropa. Ziel ist es, einen Beitrag in Bezug auf zukünftige Konzepte zur Netzregelung zu leisten, die eine effiziente und hohe Frequenzqualität im Verbundnetz sicherstellen. Dieses erfolgt anhand einer statistischen Analyse von historischen Daten, die für zeitsequenzielle Monte-Carlo-Simulationen genutzt werden. Diese ermöglichen es, aktuelle Regelstrukturen, aber auch Kopplungskonzepte unter zukünftigen Erzeugungs- und Nachfragestrukturen zu untersuchen.

Obwohl die Dominanz von stündlichen Fahrplanintervallen und den resultierenden Stundenprodukten ein vorhersagbares Betriebsmuster mit sich bringt, haben marktinduzierte Ungleichgewichte einen hohen Einfluss auf die Frequenzqualität. In diesem Zusammenhang werden die Vorteile harmonisierter Rampen sowie die Verringerung der Fahrplanintervalle diskutiert. Die Regelstrukturen können schrittweise zentralisiert werden in Kontinentaleuropa. Austauschprozesse für Ungleichgewichte und Regelreserven können im Rahmen der verfügbaren Transferkapazitäten umgesetzt werden. Der Austausch von Ungleichgewichten benötigt keine zusätzliche Harmonisierung der Netzregelprozesse und -produkte. Der Austausch von Regelreserven hingegen kann nur dann auf einer diskriminierungsfreien Basis umgesetzt werden, wenn die Regelenergiedimensionierung wie auch die Aktivierungsprozesse harmonisiert sind, um eine vergleichbare Erbringung zu gewährleisten.

Die Resultate implizieren, dass Netzbetreiber und nationale Regulierungsbehörden stärkeren Fokus auf den Zusammenhang zwischen fahrplanbasiertem Betrieb und Marktaktivitäten sowie die Abhängigkeiten zwischen lokalen und grenzüberschreitenden Netzregelprozessen legen sollten.

Contents

List of Symbols

β	Frequency-response characteristic
$\boldsymbol{\Omega}^{\mathsf{dis}}$	Distribution function
$\boldsymbol{\Omega}^{\mathsf{sha}}$	Distribution cost matrix
$\boldsymbol{\Pi}$	Weight vector
$\boldsymbol{B}^{\mathsf{imb}} = (b^{\mathsf{imb}})$	Imbalance incidence matrix
$\boldsymbol{B}^{\mathsf{res}} = (b^{\mathsf{res}})$	Reserve incidence matrix
$\boldsymbol{B}^{\mathsf{tie}} = (b^{\mathsf{tie}})$	Tie-line incidence matrix
$\boldsymbol{C} = (c)$	Transfer capacity matrix
$\boldsymbol{I}$	Unit matrix
$\boldsymbol{P} = (p^{\mathsf{imb}})$	Vector of imbalances
$\boldsymbol{R}^{\mathsf{res}} = r^{\mathsf{res}}$	Reserve vector
$\boldsymbol{x}$	Combined decision vector
δ	Disturbance
γ	Factor to determine self-regulation effect
κ	Kurtosis
λ	Number of trips of a unit
$\mathbb{R}$	Set of real numbers
$\mathcal{N}$	Normal distribution
μ	Mean value

ω^{dis}	Distribution cost function
ω^{imb}	Imbalance sharing function
ω^{res}	Reserve sharing function
ω^{tie}	Usage of tie-line function
Φ	Set of tie-lines between two adjacent areas
ϕ	Electricity price
σ	Standard deviation
A	Set of control areas
a, b, ς, α	Constants
A^{uo}	Steady state availability of unit
D	Effect of self-regulation
E	Expected value
F	Distribution function
f	Frequency
$f(.)$	Probability function
f^{off}	Time correction offset
f^{phys}	Measured frequency
f^{set}	Set frequency
f_0	Nominal frequency
g	Contribution coefficient
H^{tot}	Total inertia of synchronous area
i, j, k, l, m, n	Index variables
K	Frequency bias factor

N	Number of control areas
P	Power
p	Probability
p^{def}	Reserve deficit probability
P^{tie}	Tie-line capacity after imbalance sharing
q	Estimation coefficient
S	Synchronous area
s	Laplace transformation variable
$S^{(\cdot)}$	Contribution to the bias factor
S_{B}	Total rated power
T	Set of net tie-lines
$T^{(\cdot)}$	Time period
U	Voltage
x	Decision variable

1. Introduction

1.1. Background and Motivation

One of the core responsibilities of a Transmission System Operator (TSO) is real-time control of mismatches between the consumption and production of electric power, i.e. frequency control. The operating principles for the interconnected power system in Continental Europe were defined more than sixty years ago. For decades, vertically integrated utilities managed the electricity supply under monopolistic structures. With the liberalisation of the energy markets, which was initiated in Continental Europe in the late 1990s, these structures began to dissolve. As illustrated by Figure 1.1, the European power system has been exposed to high and persisting frequency deviations since unbundling of the electricity sector started. The figure shows how often and for how long the absolute frequency deviation exceeded 75 mHz per month in the Continental European power system. This threshold is 50 % above the standard frequency range of 50 mHz, which means there is a significant imbalance between scheduled production and actual demand in the system. The increasing deviations together with the seasonal variations are evident. There are several underlying reasons for this development:

Unbundling and schedule-based operation: In the process of liberalisation, the electricity industry evolved from a monopoly operated by vertically integrated utilities to a competitive market. In liberalised electricity markets, Distribution System Operators (DSOs) and TSOs bear responsibility for the operation and security of the power system. Kirby and Hirst [88] identified the need for auxiliary functions in an unbundled system and classified these ancillary services accordingly. The need for ancillary services gave rise to a competitive ancillary service market operating in tandem with the wholesale market, as elaborated by Joskow [86] as well as Singh and Papalexopoulos [136]. As TSOs do not usually possess any generation, they must, in par-

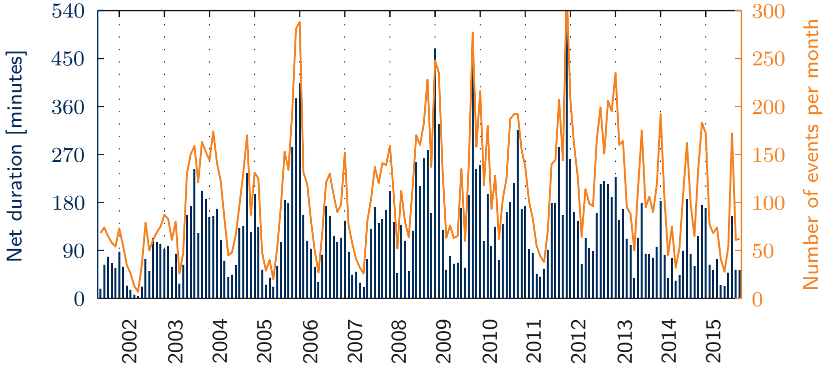


Figure 1.1.: The 75-mHz-criterion applied to the system frequency of Continental Europe (overview of October 2001 to December 2015; earlier recordings were not available).

ticular, have access to active power reserves and use market-based mechanisms to acquire active power reserves. Hence a TSO's access to active power reserves is limited to the contracted amount which might not be sufficient to balance the mismatch between scheduled production and actual consumption in real-time. A comprehensive overview of ancillary services is given by Rebours et al. [114, 115], whereas Kuzle et al. [92] outlined ancillary services in an open market environment. However, nomenclature and respective products differ not only across continents, but also within Europe.

Furthermore, electricity trading implies a schedule-based system operation instead of real-time load-following. Every trading, generating, and consuming entity in a power system is assigned to a so-called Balance Responsible Party (BRP). A BRP is in charge of the compilation of the net balance of anticipated trade, supply, and consumption of energy. The owner of this role is allowed to buy or sell energy on wholesale markets and delivers schedules of its net balance to the associated TSO. BRPs in Continental Europe report schedule notifications to the TSO per defined imbalance period. If the provided schedules match the mean value of the load, the difference between scheduled and actual load has to be compensated by the TSO. Weißbach and Welfonder [160] demonstrated the impact on frequency quality of market-induced imbalances linked to the imbalance period, as power plant operation shifts from load-following to schedule-based operation.

Decentralised intermittent generation: The production mix in the European power system is changing from centralised large conventional units to decentralised and intermittent generation, which is emphasised by the decision of several countries to abandon nuclear power [4, 18,36,145]. Wind and solar power have been adding volatility and operational complexity to the system in recent years, causing additional imbalances between planned and actual generation. As the European Union, according to its 20-20-20 targets, is striving for a green future, this trend is likely to continue [58,113]. The impact of intermittent generation penetration on system operation and operational reserves is discussed in [33,38,96,135]. Especially the impact of increasing wind and photovoltaic power penetration has been the subject of in-depth analysis. Söder [135] and Dany [33] introduced investigations that quantified the technical consequences of increasing wind power for operational reserves by probabilistic methods, whereas Voorspools and D'haeseleer [156] showed the shortcomings of deterministic methods. Integrating photovoltaic and wind generation generally impacts control and load-following requirements [94,96]. Doherty and O'Malley [38] quantified the reserve provision in a system taking into account the uncertain nature of wind power; the reliability of the system was used as a means for determining the effect of increasing intermittent power penetration. Brückl [17] elaborated a similar method based on Monte Carlo simulations. Makarov et al. [95] gave a comprehensive overview of the sources of uncertainties in power systems, their important characteristics, and models for integrating uncertainty information into system operation.

This thesis discusses the link between these trends and the decrease of frequency quality that the European power system has been exposed to in recent years. Assuming these developments continue within the current decentralised and country-specific frequency control framework, security of supply has to be weighed against the increasing demand for active power reserves. This thesis investigates technical and organisational shortcomings of the frequency control setup in Continental Europe under current and expected future conditions. The objective of this thesis is to contribute to future concepts of frequency control ensuring an efficient and high frequency quality in the European interconnected power system under the above-mentioned ongoing structural changes. Historical data are statistically analysed and used for Monte Carlo simulations, which enable the investigation of future demand and production portfolios. The work is built around the requirements for practical application. First, the control structure must be suitable for an unbundled electricity market in which, due to vertical disintegration, only limited data are available to the TSOs. Second, it should take into account any existing technical infrastructure such as measuring equipment or monitoring and control devices.

1.2. Contributions

The main contributions made by this thesis can be identified as follows:

- A generalisation of the fundamentals describing the roles and responsibilities in energy balancing and frequency control in Europe is given. The consequences of a rising level of liberalisation and the ensuing policy implications are elaborated and illustrated with the example of the Swiss power system and real-life frequency measurements.
- A reduced synchronous area model for Continental Europe is derived that can be used to describe the frequency dynamics and transfer capacities between managed areas.
- A framework to minimise control actions is introduced, and a pan-European imbalance sharing process is described in order to minimise imbalances before activating active power reserves. Distribution rules are proposed that allow sharing imbalances on a non-discriminatory and non-hierarchical basis.
- The concept of reserve sharing is adapted to provide an integrated pan-European frequency control setup that areas can use to support each other in order to improve frequency performance.
- To evaluate the actual implication and effectiveness of the proposed enhancements to the current frequency control setup, a time-sequential model is elaborated which allows the investigation of the status quo as well as future scenarios.

- Deterministic approaches to improve the determination of the frequency bias factor, and thus the local imbalance of an area, are presented.

1.3. Outline of the Thesis

The thesis is divided into the following chapters which include separate, brief introductions:

Chapter 1 discusses the motivation of this thesis and outlines the main contributions.

Chapter 2 introduces the reader to the basic European framework of matching electricity generation and consumption. It elaborates the principle elements of a power system and provides an overview of the balancing parameters. These are further elaborated with regard to control structure, division of responsibilities, and policy implications.

Chapter 3 discusses the different approaches and possibilities towards a gradual centralisation of control actions across countries, proposes subsidiary measures for harmonisation, and derives a reduced synchronous area model.

Chapter 4 elaborates the different properties of the imbalances that cause a mismatch between scheduled generation and actual demand and defines scenarios for developments in Europe. Together, they build the basis for using a Monte Carlo method to simulate imbalances relevant to frequency control.

Chapter 5 applies the imbalance model of Chapter 4 to the simulation framework based on the steps towards the centralisation of frequency control outlined in Chapter 3. Results as well as challenges are discussed.

Chapter 6 draws conclusions and provides an outlook on associated future research.

1.4. List of Publications

The following papers have been published in the course of working on this thesis:

Journal Papers

- Marc Scherer, Oliver Haubensak, and Thorsten Staake
  Assessing Distorted Trading Incentives of Balance Responsible Parties Based on the Example of the Swiss Power System
  Energy Policy, Volume 86, pp. 792–801, 2015, ISSN 0301-4215.

- Marc Scherer, Marek Zima, and Göran Andersson
  An Integrated Pan-European Ancillary Services Market for Frequency Control
  Energy Policy, Volume 62, pp. 292–300, 2013, ISSN 0301-4215.

Conference Papers

- Marc Scherer and Göran Andersson
  A Blueprint for the European Imbalance Netting Process Using Multi-Objective Optimization
  IEEE Energycon 2016, pp. 1–6, 4 to 8 April 2016, Leuven, Belgium.

- Marc Scherer and Pavel Zolotarev
  Frequency-Response Coupling Between Synchronous Areas in Europe
  IEEE PowerTech Eindhoven, pp. 1–6, 29 June to 2 July 2015, the Netherlands.

- Marc Scherer and Göran Andersson
  How Future-Proof Is the Continental European Frequency Control Structure?
  IEEE PowerTech Eindhoven, pp. 1–6, 29 June to 2 July 2015, the Netherlands.

- Miguel de la Torre Rodríguez, Marc Scherer, David Whitley, and Frank Reyer
  Frequency Containment Reserves Dimensioning and Target Performance in the European Power System

IEEE PES General Meeting, pp. 1–5, 27 to 31 July 2014, Washington, the United States.

- Marc Scherer, Emil Iggland, Andreas Ritter, and Göran Andersson
  Improved Frequency Bias Factor Sizing for Non-Interactive Control
  Cigré 2012 Session, C2-113, 26 to 31 August 2012, Paris, France.

- Farzaneh Abbaspourtorbati, Marc Scherer, Andreas Ulbig, and Göran Andersson
  Towards an Optimal Activation Pattern of Tertiary Control Reserves in the Power System of Switzerland
  American Control Conference (ACC), pp. 3629–3636, 27 to 29 June 2012, Montréal, Canada.

Non-Peer Reviewed German Journal Papers

- Matthias Haller, Marc Scherer, and Bernd Geissler
  Erfahrungen im deutschen Netzregelverbund – Eine erste Bilanz nach einem Jahr operativen Betriebs
  Bulletin SEV/VSE, Volume 8, pp. 17–19, August 2013, Switzerland.

- Marc Scherer and Bernd Geissler
  Das Konzept Netzregelverbund – Hintergründe der Kooperation von Übertragungsnetzbetreibern
  Bulletin SEV/VSE, Volume 5, pp. 27–29, May 2012, Switzerland.

- Andreas Burger, Marc Scherer, and Martin Beck
  Zusammenschluss von dezentralen Erzeugern zur Netzregelung – Das Konzept des Tertiärregelpoolings
  Bulletin SEV/VSE, Volume 12, pp. 12–15, December 2011, Switzerland.

- Marc Scherer
  Richtige Regelreservedimensionierung – Validierung und kontinuierliche Anpassung
  ew – Magazin für die Energiewirtschaft, Volume 110(24), pp. 62–65, November 2011, Germany.

- Marc Scherer
  Fahrpläne müssen eingehalten werden
  ENERGY.NOW!, Volume 4, pp. 18–19, August 2011, Switzerland.

- Marc Scherer
  Verbesserung der Frequenzstabilität – Anreizbasierte Berechnung der Ausgleichsenergie
  ew – Magazin für die Energiewirtschaft, Volume 110(12), pp. 32–35, May 2011, Germany.

- Marc Scherer
  Frequenzschwankungen durch nicht konforme Fahrplanwechsel – Ein verbundweites Problem und die Schweizer Lösung
  Bulletin SEV/VSE, Volume 3, pp. 16–19, March 2011, Switzerland.

Parts of this thesis have been published in some of the above-mentioned papers. These will be referenced in the introductory section of the respective chapters and in the bibliography in Chapter 7.

2. The Basics of Matching Demand and Production

This chapter reviews the general aspects related to matching electricity production and consumption in Europe. This framework comprises the principle elements of a power system, different matching timescales, and an overview of roles in a liberalised market environment. These are further elaborated with regard to the control structure and the division of responsibilities.
Parts of this chapter have been published in [22,119,120,122].

2.1. The Principle Elements of a Power System

The technical organisation of a power system comprises three domains which can be described as follows: A consumer converts electricity into useful energy ("consumption"). This electricity is made available to the consumer by the conversion of primary energy into electricity ("production") and the deduction of transfer losses ("transportation").

In the following sections, these three domains as well as the economic framework are briefly outlined to form a basis for the matching framework of electricity production and consumption.

2.1.1. Load Characteristics

Consumption is the motivational element of a power system. Its variation versus time is called load profile: The seasonality characterises the yearly profile, and the light-dark cycle shapes the daily profile.

In the long-term, load profiles are determined by economic and demographic growth as well as technological progress. The latter concerns efficiency, new possible uses such as heat pumps [25] or vehicle-to-grid applications [68], and demand response. Economic growth impacts the long-term electricity consumption. Baranzini et al. [8] concluded a robust long-running causal relationship between gross domestic product and electricity consumption. Ciarreta and Zarraga [28] outlined how this relationship can be used to predict the gross domestic product and concluded that a 1 % increase in electricity consumption implies a 0.3 % increase in economic growth in Europe in the long-run.

Base and Peak Load

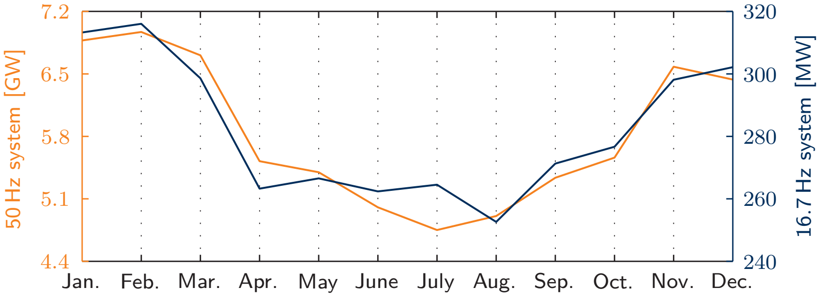
In planning and operational matters two main categories of load – and eventually power plants (see Section 2.1.3) – can be identified: base load and peak load[1]. Base load is the constant part of the total load in a power system and the minimum amount of power that must be available to the customers in that system. It mainly depends on the climate zone, i.e. the need for continuous heating or cooling, and the extent of industrial plants manufacturing at night.

Peak load (or peak demand) is the maximum load in a power system and indicates the additional demand in a power system over and above base load. In Europe, peak load periods generally occur in the morning and evening: The morning peak is a combination of industrial and domestic demand whereas the evening peak is predominantly domestic demand.

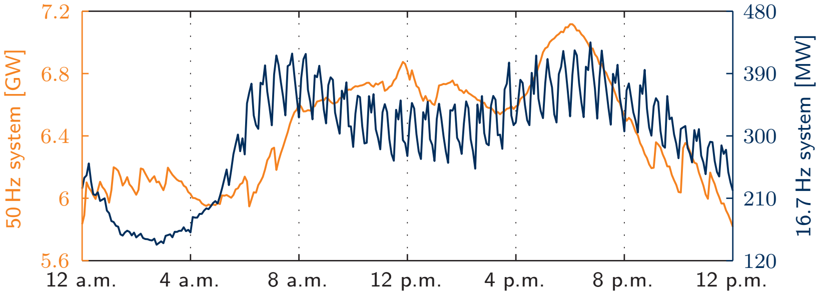
The respective base or peak load naturally depends on the period under observation (seasonal variations, economic circumstances, climate changes) as well as the area of interest (size of area, geographical location). At a rough guess, throughout a whole year the base load is typically 30 % of the peak load [28].

Figure 2.1 shows the average daily load profile and the average monthly load for both the Swiss 50 Hz supply and the 16.7 Hz traction supply system to illustrate the seasonality and daily load variation in two neighbouring power systems. The seasonal trend is quite similar, due to an equal temperature dependency and the same geographical location. The daily pattern varies widely because of the difference in the load characteristics. In the traction supply system, peak load occurs before and after business hours when people go to work and return home. In the 50 Hz power system, peak load occurs during lunch-time and in the evening: In winter, record evening peaks occur with the increased use of domestic electric heating appliances. Another local maximum can be observed after the start of low

[1] The term medium load or intermediate load is rarely used and mostly found in German literature [37,82]; it means slow load variations that can be supplied by less flexible production.



(a) The average monthly load displays the seasonality.



(b) The average daily load profile displays the load variability.

Figure 2.1.: Average load in 2011 for both the Swiss 50 Hz supply and the 16.7 Hz traction supply system.

tariff time at 10 p.m. in Switzerland. It is also noticeable that both systems exhibit comparable load variability, notwithstanding the large difference in size – maximum peak loads of 700 MW versus 11 GW. The reason for the high load variability in the train system is the regular-interval timetable of public transport, i.e. on main traffic axes trains leave the railway station every half hour and load changes of 50 % within minutes are not unusual. This illustrates that load characteristics directly impose requirements on production flexibility, unit commitment, and network topology.

2.1.2. Transmission and Distribution

Every electricity consumer has to have access to a power source, i.e. electricity production. The present-day interconnected network comprises different voltage levels which differ in function, the degree of meshing, and organisational structure. According to Formula 2.1, the active power losses P^{los} due to a power transmission P on a line decrease with increasing voltage U.

$$\frac{P^{\text{los}}}{P} \sim \frac{P}{U^2} \tag{2.1}$$

The higher the voltage, the smaller the transportation losses, but the larger the investment costs. The distance and capacity of electricity transportation determine the economic optimum for the voltage level. Every voltage level is delimited by transformers[2]. Figure 2.2 shows the typical European voltage level structure.

Large-distance electricity transfer is carried out at the highest voltage levels with a typical nominal voltage of 220 kV or 380 kV. Import and export relate to cross-border exchanges between countries or control areas. The interconnecting lines are referred to as tie-lines and the highest voltage levels are referred to as the transmission system. It may also comprise electricity transmission by HVDC links or submarine cables which are both used to interconnect synchronous areas [157]. The lower voltage levels

[2] The "war of currents" ended in the late 1800s when alternating current arose as the dominant power supply medium. Its key advantage has been the invention of the transformer that can easily step voltages up and down.

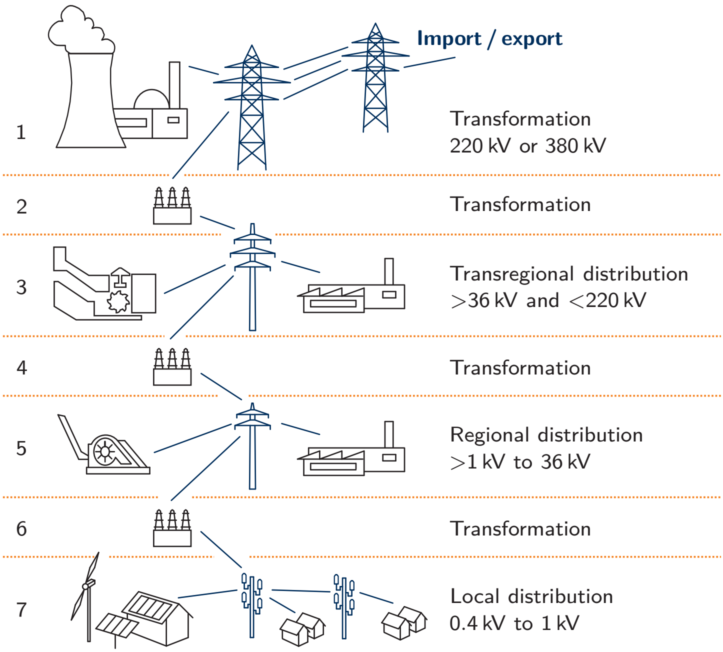


Figure 2.2.: Common network and voltage levels of alternating current systems in Europe. High-Voltage Direct Current (HVDC) transmission links are often operated at voltages higher than 400 kV (figure inspired by [153]).

are referred to as different kinds of distribution systems. This classification affects the role models in system operation, as will be elaborated in Section 2.2.1.

Large power plants, such as hydroelectric pumped storage or nuclear electricity plants, are usually connected to the transmission system. Run-of-river hydroelectric and smaller thermal power units are mostly connected to the 110 kV voltage level, whereas small distributed generation is located in the lower voltage levels. Consumers can be connected to any voltage level depending on their nominal load. For example, large industrial facilities are often connected to the 110 kV voltage level, whereas households are exclusively connected to the lowest voltage level in the local distribution network.

The traditional flow of power in the power network is top-down, i.e. from the transmission system via the distribution system to consumers. The degree of meshing generally decreases with the nominal voltage. However, distributed generation, such as photovoltaic systems which are usually located at the lowest voltage level of end-consumers, has led to an increased trend of reversed flows from lower to upper voltage levels. The upper levels show a meshed network topology, whereas the lower levels feature a radial one, i.e. a loss of electricity supply is more likely to occur in a local distribution network than in the transmission system.

In April 1958, the interconnected cross-border power network was established through a 220 kV interconnection of Switzerland, Germany, and France in the Swiss city of *Laufenburg* [100]. Nowadays, the European power system consists of 306 974 km of alternating current transmission lines and 5719 km of HVDC transmission lines, i.e. lines with a nominal voltage above 220 kV [50]. Its transmission network is spread over five synchronous areas[3] and two isolated systems[4]. The system frequency is 50 Hz in each area.

[3] These synchronous areas are structured to form five so-called regional groups: Regional Group Continental Europe (RGCE), Regional Group Nordic, Regional Group Baltic, Regional Group Great Britain and Regional Group Ireland.

[4] The two islands are Cyprus and Iceland. There are also several smaller isolated systems, but none of these has a transmission network.

2.1.3. Production Structure

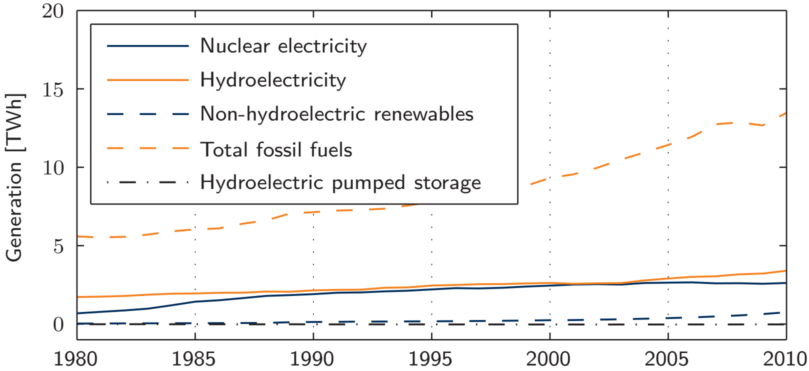
The geographical location as well as the landscape and historical conditions have substantially determined the primary energy used for electricity production in a given area. Nuclear, coal, and gas are the most common conventional large-scale generation sources and account for the largest share of overall electricity production. The current overall share of variable renewable generation sources, such as wind and solar power, is comparatively small, but growing. Various new ideas of how to supply electricity, predominantly from intermittent sources, have been presented to the public [58, 113]. They have been of high political interest for coping with climate change and have benefited from renewable promotion policies in recent years. One of these are the 20-20-20 targets set by the European Union for 2020 in its climate and energy directive: a 20 % reduction in greenhouse gas emissions as compared to 1990 levels, an increase of renewable energy to 20 % of total energy production, and a 20 % reduction in the energy consumption levels projected for 2020 by improving energy efficiency [61].

Figure 2.3 shows the advancements made in the worldwide, European[5], and Swiss production structure. On a global level, fossil-fuel power has increased all the time and now exceeds every other generation source many times over. Nuclear power and hydroelectricity account for a fairly constant share of the worldwide electricity production. The only significant drop in fossil-fuel and nuclear power coincides with the global financial crisis which began in 2007.

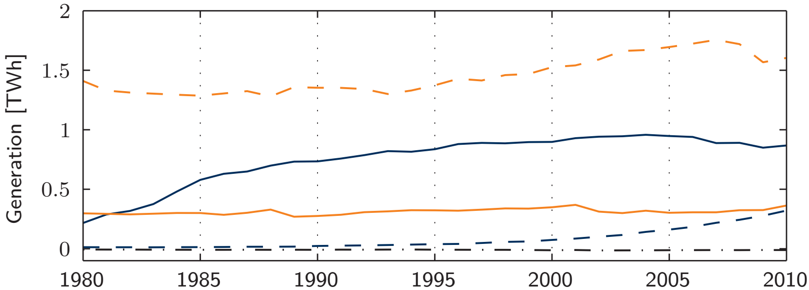
Europe distinctly deviates from the global average. It exhibits a high amount of renewable energy generation, which nowadays is on a par with hydroelectricity. This is due to political ambition such as the above-mentioned 20-20-20 targets which resulted in the continuing and rapid growth of installed variable renewable generation capacity. Examples of countries considered to be vanguards in dealing with the challenges associated with a high penetration of variable generation are Germany, Spain, and Denmark [70,76,94,99].

Using almost 40 % nuclear and 60 % hydro power, Switzerland shows

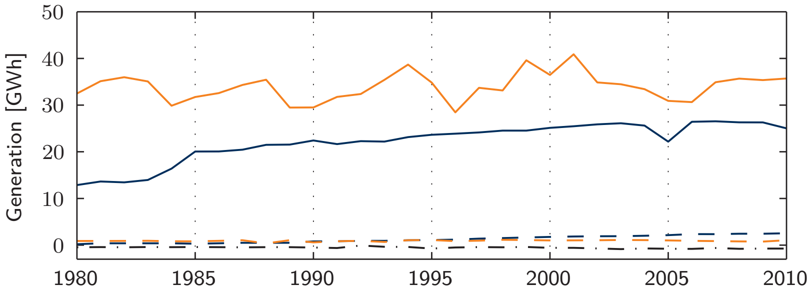
[5] EU-27 (as from 1 January 2007): Belgium, Greece, Luxembourg, Denmark, Spain, the Netherlands, Germany, France, Portugal, Ireland, Italy, United Kingdom, Austria, Finland, Sweden, Poland, the Czech Republic, Cyprus, Latvia, Lithuania, Slovenia, Estonia, Slovakia, Hungary, Malta, Bulgaria, Romania.



(a) World.



(b) Europe (EU-27) (same legend as in Figure 2.3a).



(c) Switzerland (same legend as in Figure 2.3a).

Figure 2.3.: Electricity net generation between 1980 and 2010. The data were gathered by the U.S. Energy Information Administration (EIA) [150].

an untypical and bipolar production structure; it is carbon-neutral for the most part, but non-sustainable[6] regarding nuclear power. A drop in nuclear power occurred in 2005 due to a generator being damaged by an earth fault in the nuclear power plant of *Leibstadt*, which led to a significant down-time [78]. The fluctuation in hydroelectricity production is the result of changeable weather conditions, the ensuing amount of precipitation, and, due to its high flexibility and low variable costs, the traded volume which is subject to market activity and prices.

Similar to load, production classifies into peaking load and base load power plants. The difference is in the economics and the engineering limitations of the power plants. Power plants supplying base load power typically are coal-fired, nuclear, run-of-river hydroelectric, or geothermal. They run for long periods of time without significantly changing their power output; their total operating hours are roughly more than 5000 h per year. Flexibility requirements are comparatively low – for example, a thermal unit may take days to reach full power once fired up – and so are the variable costs. Peaking power is generated by hydroelectricity and gas turbines; to cover peak load, plants have to come online without much delay and start generating power at a moment's notice and for short periods of time; their total operating hours are mostly less than 2000 h per year. The flexibility requirements are high and so generally are the variable costs.

In addition, there are power plants of an intermediate kind, often referred to as load-following plants[7]. They typically are lignite-fired or coal-fired and supplement the power produced by base load plants. With this classification, solar power is mostly peaking power, as sunny afternoon hours (see Figure 2.1b) more or less coincide with peak electrical demand. Wind power, however, is not constant enough to be base load power, and not reliable enough to provide a secure source of peaking power.

2.2. Economic and Legal Principles

The three domains of the technical organisation outlined in Section 2.1 mirror the value-added chain in a power system. The actual implementation

[6] In 2011, the Swiss federal council decided to phase out nuclear power by 2034. The parameters are currently under discussion in the ongoing legislative process [110].

[7] Similar to medium and intermediate load, the terms medium and intermediate load power are rarely used (see Section 2.1.1).

depends on the chosen market design and the respective legal basis: Over the last few decades, the European Union has developed a legal framework for a highly unbundled market structure in Europe.

2.2.1. Regulatory Framework and Historical Development

A feature of power plants and power networks is their high capital costs. The power network forms per se a natural monopoly[8], while electricity production up to a certain critical demand also forms a natural monopoly, because, due to very high fixed costs, average costs are above marginal costs [138]. Therefore, monopolistic structures with vertically integrated[9] utilities characterised the power system in the past, and such structures are still common in island systems and isolated systems. An integrated utility has territorial sovereignty, and the choice of electricity supplier is dictated by the geographical location of the consumer. The sovereignty guarantees access to the power network which is vital for power plants that bear high risks due to their specificity, large capital costs, and an average life cycle of around 30 years. On the other hand, it theoretically allows energy utilities to dictate prices and delivery conditions.

Without territorial sovereignty, market entry barriers for new producers are lower and customers can choose their supplier freely. However, in extreme cases energy market liberalisation can lead to a decrease in system security [84,87]. Therefore, guaranteed and free market access as well as the unbundling of production and transportation are necessary to create and promote a genuine competition on the supply side.

In the early 1990s, the liberalisation of European energy markets started in the United Kingdom, followed by Scandinavia. In 1996 the "Directive 96/92/EC" set the basis for the European-wide unbundling of the electricity market [59]. It was superseded by the "Directive 2003/54/EC" in 2003 [60]. The directives provide for non-discriminatory access to the

[8] A natural monopoly is a state in which it is most efficient for the market to be served by a single provider, i.e. the capital cost to build another transmission network is so high that it effectively bars potential competitors from the market. However, before the development of the 50 Hz standards in the mid-1900s, competing networks and frequencies between 30 Hz and 70 Hz existed in Continental Europe [100].

[9] A vertically integrated utility performs "at least one of the functions of transmission or distribution and at least one of the functions of generation or supply of electricity" [60].

power network, i.e. so-called third-party access. System operators have to grant access to dependent and non-resident energy suppliers. In return the system operator receives a transport fee, which is reviewed by the national regulatory authorities.

The stipulated unbundling of network activities from production and supply activities ensures that producers and distribution companies cannot simultaneously act as system operators. Because of this, they cannot give privileged transmission rights to their own production units or cross-subsidise production by third-party network usage tariffs. There are various types of unbundling [24]. "Directive 96/92/EC" stipulated an unbundling of accounts, whereas "Directive 2003/54/EC" put the accent on legal unbundling. Due to this unbundling, a distinction must be made between economic and physical transactions: Electricity trading leads to cash flows between producers, traders, and consumers; system operators are not involved. However, the resulting physical flow takes place in the power network under the responsibility of the system operators, but a costs-by-cause allocation is not possible, which is why the transportation fees are socialised among the network users.

Types of System Operators

There are three possible types of system operators [60,62]:

Distribution System Operator (DSO): This is a company responsible for operating, developing, and maintaining the distribution system in a given area as well as its interconnections to other systems. According to Figure 2.2, this area may encompass one or more different voltage levels. Thus, there can be multiple cascaded DSOs in an area, resulting in so-called intermediate DSOs.

Transmission System Operator (TSO): Similar to a DSO, this company is responsible for operating, developing, and maintaining the transmission system as well as its interconnections to other systems. As elaborated in Section 2.1.2, the transmission system always encompasses the highest voltage levels; therefore, there can only be one TSO in a designated geographical area[10]. This area is generally referred to as a control area stipulating the frequency control responsibility, as will

[10] In this regard, the Independent System Operator (ISO) and the Independent Transmission Operator (ITO) are different legal forms for unbundling the ownership of a TSO. Especially in American literature the term ISO is commonly used. In this thesis, only the term TSO will be used.

be elaborated in Section 2.3.3. In Europe, the transmission networks are operated by TSOs.

Combined operator: As the name implies, this is a combined transmission and distribution system operator. This type of system operator can often be found in small countries such as Luxembourg.

In 2009, the "Directive 2009/72/EC" entered into force as part of the so-called third legislative package on energy liberalisation or simply the "3rd energy package" [61]. It included further rules on ownership unbundling and the establishment of a national regulatory authority in each member state. Moreover, the Agency for the Co-operation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) as umbrella bodies[11] of the national TSOs were given a legal mandate [63].

In this context, there is no limitation for the number of system operators in Europe and their territorial area has evolved historically. It is common to have one TSO per country. Currently, the exceptions in Europe are Germany and the United Kingdom with four TSOs each and Austria with two, forming a total of 41 TSOs from 34 countries in the ENTSO-E [53]. The number of DSOs varies greatly among European countries. For example, there are roughly 700 DSOs in Switzerland [141].

Framework Guidelines and Network Codes

The objective of ENTSO-E is to develop and strengthen the liberalised European electricity market, but also to set technical standards to be met by national TSOs in terms of operating national transmission networks. Furthermore, ENTSO-E identifies projects of common interest which will be crucial for system adequacy (see Section 2.3) in the future European transmission network. The ACER has been appointed to develop Framework Guidelines on whose basis the ENTSO-E has to write Network Codes [62]. The Framework Guidelines are legally non-binding by nature, whereas the Network Codes are legally binding once they are approved by the European Commission. Additional region-specific operational TSO requirements are defined in system operation agreements; in RGCE this is the Operation Handbook (OpHB).

[11] In 2009, the five European synchronous areas, i.e. the regional groups mentioned in Section 2.1.3, were incorporated into ENTSO-E; thus, the Union for the Co-ordination of Transmission of Electricity (UCTE), which until July 1999 was known as Union pour la coordination de la production et du transport de l'électricité (UCPTE), continues to exist as RGCE.

The purpose of the Network Codes is to set up European-wide rules for the harmonisation of electricity markets and system operation. They aim at providing effective and transparent access to the transmission systems across borders. However, the number and scope of these codes have not been predefined. "Regulation 714/2009/EC" only sets out the areas in which Network Codes will be developed as well as a process for developing them. Drafting of the first Network Codes started in 2010. For a more detailed discussion of the Network Codes see Section 2.4.2.

2.2.2. Market Principles

As depicted in Figure 2.4, there are two possibilities in Europe to sell or buy electricity on a wholesale market, either Over the Counter (OTC) or on energy exchanges. On OTC markets, electricity is traded bilaterally between two parties which negotiate individual products consisting of a volume, a price, and an arbitrary delivery period. In contrast to these non-standardised contracts, trading on energy exchanges is based exclusively on predetermined products for different time horizons such as one year or one month ahead, hourly, or quarter-hourly. Energy markets and OTC may offer the same product, i.e. electricity for a certain time period. Since the prices on an energy exchange are transparent to every market participant, they serve as a reference for OTC trades. Therefore, arbitrage between OTC and energy exchanges equalises price differences between them. This reference function of exchange prices certainly depends on the level of liquidity of the market, i.e. the level of market information incorporated in the resulting prices [37].

Market participants have several standardised time horizons to trade on power exchanges which differ depending on the lead time before the actual physical delivery. There are financial markets for derivatives as well as physical markets.

Future and Forward Contracts

The contract partner of a future or forward[12] contract is obliged to buy or sell a certain amount of energy at a certain time in the future. These markets offer participants the possibility to trade electricity several years or months before physical delivery; they are used to hedge against risks caused by the volatility of spot market prices. Normally, future and

[12] Figure 2.4 does not show that forward contracts could theoretically be traded on energy exchanges; however, the lack of standard features means that they actually never are.

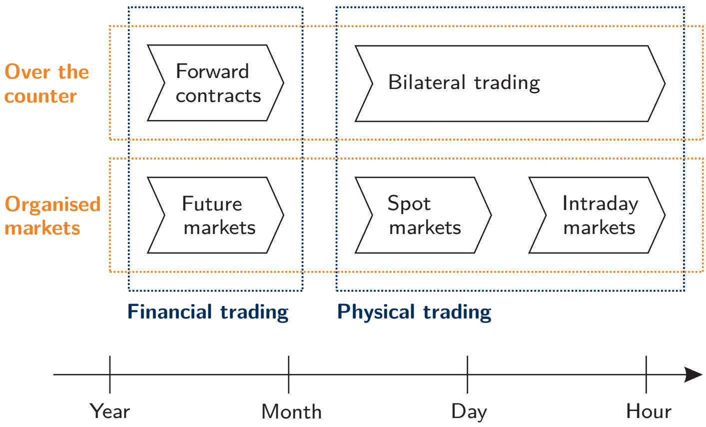


Figure 2.4.: Simplified overview of the possibilities for energy trading in Europe; not all markets necessarily exist in each country.

forward contracts only include financial trading, i.e. they do not lead to any physical performance, but they are cleared on spot markets during their delivery period.

Spot Markets

Short-term delivery contracts traded on day-ahead spot markets always lead to physical delivery on the following day. Electricity is usually traded hourly, i.e. as 24 hourly products for each day, or in blocks for fixed time periods such as base (12 a.m. to 12 a.m.) or peak (8 a.m. to 8 p.m.) products. In day-ahead trading, each market participant places buy and sell orders for respective next-day delivery. Thus, for each hour of the day, each market participant of the power exchange has an individual bid and demand curve. At gate closure time, for example, 12 a.m. day-ahead, these individual orders are put together by the power exchange operator resulting in an aggregated demand and supply curve. Just like in any other market, the point of intersection of these two curves determines the spot price and the entire amount of energy traded for a defined hour. Both results, volume and prices, are published by the power exchange. The trading volume of each market participant is then calculated dependent on their individual bids.

Generally, the spot market price is characterised by high volatility due to short-term changes in the supply and inflexible daily or seasonal load patterns. For example, energy demand is higher during daytime and subsequently energy prices are higher in peak times than at night (see Section 2.1.1).

Intraday Markets

In several countries contracts for the next day can be traded from, for example, 3 p.m. on the day-ahead market. Typically, trading is possible up to one hour prior to delivery. Market participants can correct mistakes or mismatches in their portfolio on the intraday market. For example, electricity that has already been sold by a generator, but cannot be delivered because of a generation outage, could be provided there. Due to a politically enforced increase in the generation of renewable energy, which mainly consists of intermittent and non-predictable wind and solar power, the significance of intraday markets in Europe has been rising in the last few years.

Congestion Management

In liberalised electricity markets, the transmission system determines the limitation for wholesale trading [128]. Consequently, the way in which cross-border transfer capacities are calculated and allocated to market participants has a substantial impact on market activity and liquidity. In Europe, the TSOs bear responsibility for the operation and security of the power system, which includes the determination of the transfer capacity available to electricity trading by market participants. Today, the most common method to determine the cross-border capacity between countries is the Available Transfer Capacity (ATC) mechanism. An alternative is the so-called flow-based methodology [109,117].

ATC Mechanism

The ATC mechanism is based on bilateral or multilateral agreements between neighbouring TSOs. Based on historical data, i.e. reference days, well representing seasonal patterns as well as justified security margins, each TSO determines a Total Transfer Capacity (TTC) for each direction on each border of its control area. Thus, the TTC is the upper limit for which the maximum physical flow on a critical network element does not exceed its safety margins, i.e. its N-1 criterion. Based on the TTC, each TSO deducts a safety margin, referred to as the Transmission Reliability Margin (TRM), taking into account unintended deviations of physical flows and measurement errors in real time. TSOs further deduct capacities of Long-Term Contracts (LTCs), as a holder of a LTC must always declare by the previous day whether or not and to what extent he intends to use the respective transfer capacities reserved on a long-term basis. The Net Transfer Capacity (NTC) available for wholesale trading results from the TTC minus the TRM minus the LTC. Finally, the ATC is that part of the NTC that remains available for further commercial activity after the conclusion of each phase of the allocation procedure, i.e. ATC is NTC minus Already Allocated Capacity (AAC). This whole process is operated bilaterally; therefore, if the calculated values deviate between neighbouring TSOs, it is the lower ones that are generally selected. By doing that, borders are considered separately, which does not allow a holistic consideration of the power flows in the power system, i.e. neither mitigating nor negative external effects caused in neighbouring lines are taken into account. Furthermore, as the ATC mechanism is applied before market outcomes are known, there is no netting of opposite flows.

Flow-Based Methodology

Instead of on fixed capacities, the flow-based methodology is based on a reduced network consisting of nodes and lines in order to take into account that in a highly meshed power system, electricity can flow along different paths. Each TSO provides input data, which are combined at a regional level. To create a reduced network model, instead of considering each and every line, so-called critical branches are introduced. They consist of tie-lines as well as internal lines that significantly impact cross-border exchange. Furthermore, Power Transfer Distribution Factors (PTDFs) are introduced, denoting the physical flow induced on a transmission line as the result of power injected at another specific node or zone, i.e. the PTDF matrix translates economic activities into physical flows. This makes it possible to determine which combinations of cross-zonal exchanges may lead to an overload of a critical network element. Only these branches are then considered in the model. Based on the physical limits and potential security margins of the line, the physical capacity of each critical branch is determined. The process of deriving the capacity available to wholesale electricity trading is similar to the one used in the ATC mechanism. Initially, the total maximum flow is available. A Flow Reliability Margin (FRM) is meant to cope with the uncertainty inherent to the process of determining the remaining capacity. Additionally, a reference flow considers the long-term nominations. What will eventually be offered to the wholesale market is the so-called Remaining Available Margin (RAM). By doing this, it is possible to consider the effects of a meshed system.

Cross-Border Trading

Once the commercially available transmission capacity is calculated it has to be made available to market participants. In Europe, mainly two mechanisms are applied: explicit and implicit auctions [37]. Explicit congestion management is characterised by two markets: capacity is made available by an auction office on a separate market taking place chronologically before the electricity market. Cross-border capacities are sold via auctions on a separate market where a market participant places bids for a certain amount of capacity for a specific period of time, i.e. a year-, a month- or a day ahead. The sum of these so-called Physical Transmission Rights (PTRs) offered in explicit auctions matches the NTC in one direction. The auction office conducts a uniform price auction and allocates the capacity until it is over. As long as the sum of the bids is below the available transmission capacity, the payment for the transmission capacity is equal to zero. Hence PTRs are sold to bidders with the highest willingness to pay. A successful bid implies the right to use a certain amount of transmission capacity for a certain period of time, for example, 200 MW from 1 to 31 January. As the electricity spot market takes place afterwards, market participants have to estimate the cross-border price differences when bidding for PTRs. This lack of information leads to an inefficient use of cross-border capacities, as, for example, capacity might be bought in the wrong direction, i.e. from the high price to the low price area. Or capacities may be under-utilised, although full usage might have been more economical, if electricity prices had been known beforehand. For this reason, explicit auctions on a day-ahead basis currently are gradually being replaced by implicit auctions, i.e. market splitting or market coupling. In an implicit auction, cross-border capacity and electricity are auctioned simultaneously: cross-border capacity is made available implicitly via the spot market electricity auction encompassing different market areas (price zones). The resulting price of electricity contains both the congestion cost and the price of the electricity itself. This results in an efficient use of cross-border capacities. In economic terms, electricity flows are always going in the right direction and capacities are fully utilised, if this is necessary from a social welfare point of view.

In practice in Central Western Europe (CWE), i.e. the Netherlands, Belgium, France, Luxembourg, and Germany, co-ordinated ATC-based market coupling was launched at the end of 2010 and was superseded by flow-based day-ahead market coupling in mid-2015 [118]. However, the flow-based method still is a rather limited regional-level application valid only for a dedicated market. As internal congestions within a TSO's control area are shifted to the border irrespective of the calculation mechanism, they still determine the commercially available transmission capacity.

2.3. The Matching Timescales

The previous two sections have set out the fundamentals of electricity supply as well as the economic and legal basics according to which the power system has to be organised and operated. The task of maintaining the balance between electricity generation and demand starts long before real-time and involves three timescales which can be seen as different functions: system adequacy, energy balancing, and frequency control. It is not always easy to say where one function ends and the other begins. As this thesis focuses on mid-term and short-term aspects, the discussion of system adequacy will be kept brief.

2.3.1. System Adequacy

System adequacy is the capability of a power system to meet generation and demand at all times, including at peak load. This refers to the adequacy of the existing or proposed system components to satisfy the system demand which is assessed over months or even years. Questions of system adequacy typically relate to power system topology planning, infrastructure investments, and development scenarios.

Since 2010, the ENTSO-E has been leading the planning of a common network within the scope of the Ten-Year Network Development Plan (TYNDP) [62]. Its major aim is to identify investment needs in the European transmission system allowing for different generation and load scenarios and their interrelations in an adequacy forecast, i.e. the Scenario Outlook and Adequacy Forecast (SO&AF).

The SO&AF focuses on technical aspects; it provides information on whether and when a system is capable of covering its load. First, system adequacy is evaluated on a national and regional level. Then, the whole ENTSO-E area is analysed. The collected data and thus the results refer to two typical hours of a year (third Wednesday in January and July from 6 p.m. to 7 p.m.). There are two scenarios covering the years 2016, 2020, and 2025: The conservative Scenario A assumes that the commissioning of new power plants does not exceed the projects confirmed today, whereas the best estimate Scenario B additionally includes new power plants whose realisation is likely to take place [46,48]. As these forecast scenarios cover a bottom-up mid-term TSO perspective, they do not necessarily meet the 20-20-20 targets of the European Union. Until 2014, a third top-down

Scenario EU2020 based on the National Renewable Action Plans (NREAP) in compliance with the 20-20-20 targets of the European Union in climate and energy policy was assessed. However, as grid development is a long-term process, further national developments as well as politically induced changes of the production structure and interconnection targets have to be considered anyway, which is why ENTSO-E developed an additional exploratory approach at the same time. Four visions frame the boundary conditions of the future landscape of the European power system until 2030 [48,51] and capture a realistic range of possible futures. Two bottom-up scenarios (Vision 1 and Vision 3) are built on the input of national TSOs following defined assumptions, whereas two top-down scenarios (Vision 2 and Vision 4) are designed to fulfil the objectives of the "3rd energy package" of the European Union. These visions are furthermore used for the market analyses that are part of the TYNDP. Both market analyses and adequacy forecasts are considered intermediate steps in keeping to the "Roadmap 2050" which outlines ways[13] to achieve the 20-20-20 targets [58].

2.3.2. Energy Balancing

Energy balancing refers to the anticipated physical exchange of energy in the power system to meet generation and demand. It takes place over minutes to months. Within the scope of liberalised markets in Europe most energy balancing takes place on wholesale markets. Hence balancing is the link between market activities and real-time operation. The following describes the basic link between energy trading and TSO business in Europe.

Schedule Notifications

Every physical transaction on an electricity market, either OTC or on a power exchange, leads to a physical flow in the power system. However, generation and network operation are unbundled; system operators are not automatically provided with information regarding the amount and the physical location of production and load. Therefore, market parties specify

[13] The "Roadmap 2050" has two main objectives. The investigation of the technical and economic feasibility of achieving a reduction of at least 80 % in greenhouse gas emissions to below 1990 levels by 2050 and deriving the implications for the European energy system [79].

their energy demand or delivery in schedules[14]. This set of values relating to power expressed in integer values of megawatts runs in consistent intervals ("clock-face scheduling") and can represent generation or consumption that results in an exchange of electricity between actors during a given time period. Thus, schedules serve various purposes: For example, a utility can specify the load profile for the upcoming days in a schedule. If it intends to purchase this amount on a wholesale market, the schedule will be equal to the buy orders placed on the day-ahead or intraday market. After gate closure time, the producers involved can supply generation schedules to their system operators, either DSO or TSO, for power flow and network security calculations.

Imbalance Period

With all schedules the so-called imbalance period defines the resolution of a schedule, i.e. the number of minutes represented by one value. Figure 2.5 shows the imbalance periods of the ENTSO-E member states, which vary between 15 and 60 minutes. The imbalance period has two implications. First, it determines the shortest duration of a standard product a market participant can purchase on an electricity market. Second, any arbitrary profile may be purchased OTC, but a standard schedule cannot describe it at a higher resolution than the imbalance period; hence a high-resolution profile can be downscaled to a schedule by building the arithmetic mean over the imbalance period.

Matching Process

There are different standards for scheduling and schedule process management. The ENTSO-E Scheduling System (ESS) represents the most common one in Europe [43]. It allows the development of standardised software applications for scheduling, which facilitates third-party access. Its guiding principle is the matching process. For every schedule there must be a counterparty schedule, i.e. for each production schedule there is a consumption schedule and vice versa. This process ensures that both parties agree on an exchange.

Balance Responsible Party

In order to co-ordinate system operation and energy trading, the energy balancing responsibility has been assigned to the role of Balance Responsible Party (BRP). Each market participant is part of a BRP, for example, utility, trader, consumer, and generator. Schematically, there are three possible types:

[14] Also referred to as "electricity market schedule" or "energy programme"; furthermore, a schedule can be classified as an internal or external commercial trade schedule in order to separate scheduling within an area from cross-border scheduling.

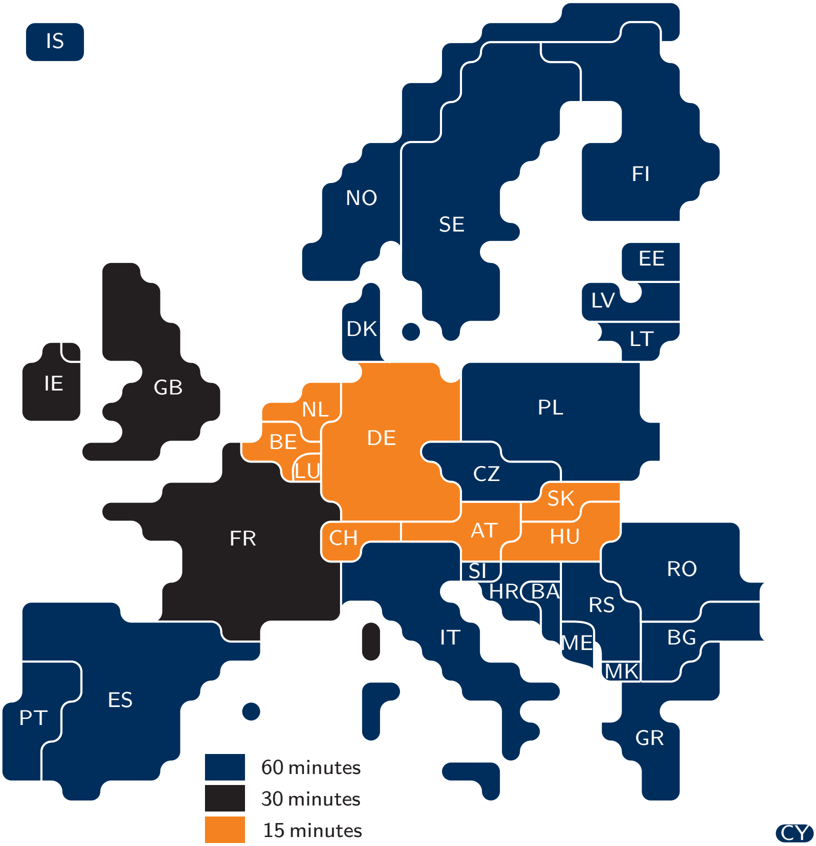


Figure 2.5.: Imbalance periods, i.e. shortest possible settlement periods in the ENTSO-E member states (dated 2014).

1. BRPs comprising load and production, i.e. both feed-in and feed-out metering points are assigned to such a BRP. This is the case for a classic utility managing a power plant portfolio and providing full service provision to consumers.

2. BRPs which comprise either load or production. The whole production or demand has to be brought to the market and the only link between demand and supply are schedule notifications, which implies a schedule-based supply of demand.

3. BRPs without any metering points. Such a BRP is reduced to a virtual construct for the purposes of billing and accounting: Traders and trading companies belong to this type. Their schedule, i.e. the sum of all their trades, must be zero.

Furthermore, a BRP is a legal entity responsible for providing schedules of its exchange with other BRPs to a central office. This central office can be an independent company; however, it tends[15] to be the TSO in the respective area, which means the co-ordination of the matching process can be referred to as part of the centrally co-ordinated ancillary services (see Section 2.3.3).

After real-time operation, the central office invoices a BRP for the deviation from its net schedule, which is equal to the sum of all import and export schedules. The BRP has to pay for so-called imbalance energy[16]. BRP in surplus ("long") receive a credit note, while billing units in deficit ("short") are charged accordingly[17]. In between this imbalance settlement and energy balancing, frequency control takes place.

2.3.3. Frequency Control

Close to real-time and ultimately in real-time, i.e. minutes to seconds, the mismatch between demand and generation determines the system fre-

[15] To the author's knowledge, the only exception in Europe is Austria where the TSO only receives the cross-border schedules.

[16] Due to frequency control, imbalance energy in Switzerland is not calculated based on these discrete trading schedules, but on ramped schedules (see Section 2.3.3).

[17] Note that negative prices are also possible. For a detailed example of the Swiss imbalance pricing mechanism see Appendix A.2.

quency[18] which is crucial for system stability in order to prevent equipment damage and, eventually, blackouts. The overall frequency control concept depends on both the physical and organisational characteristics of a power system.

Control Structure

From a greenfield perspective, the basic control structure can be designed on the basis of the physical characteristics. For this purpose, Figure 2.6 shows an abstract decision diagram.

With fully predictable load and production patterns there would be no stochastic imbalances, and the frequency could be kept at a constant level by short-term unit dispatching of a purely theoretical nature: Even with a massive amount of inertia and self-regulation, a large standard frequency range would be required in order to control the frequency by unit dispatching alone. This would barley be efficient, as devices and generators working efficiently in a large frequency range are more expensive than devices with a smaller frequency range. In a small system with little risk of network splitting, i.e. with a high degree of meshing and no congestions, frequency can be controlled centrally by, for example, one generating unit. This concept can be used in small isolated systems or quite similarly after a network split in a large synchronous area [108]. For example, the Baltic power system comprising Estonia, Latvia, and Lithuania can be classified accordingly. Frequency control is performed in the Russian system to which they are synchronously interconnected[19]. All larger synchronous areas feature a multi-tiered approach to frequency control. First, the stabilisation, i.e. the frequency containment, is done locally. In order to avoid power oscillations and to guarantee robust behaviour in an abnormal operational state, frequency containment is done by proportional control. In order to return the system to its pre-disturbance state, frequency restoration can be done manually or automatically. The latter is known as Automatic Generation Control (AGC) or Load-Frequency Control (LFC) which has (at least) proportional-integral control characteristics [91,106]. The AGC principles

[18] Obviously the concept of a system frequency does not apply to HVDC, but as the performance (for example, ramping and tripping) of large-scale HVDC components impacts the frequency of the alternating current systems they are connected to, they play an important role in frequency control [34]. This is particularly evident for large-scale HVDC lines which are often operated by respective system operating companies (in Great Britain, these may even be certified as TSOs according to national legislation).

[19] The Baltic system indeed does have frequency-response reserves as well as additional reserves in case of emergency.

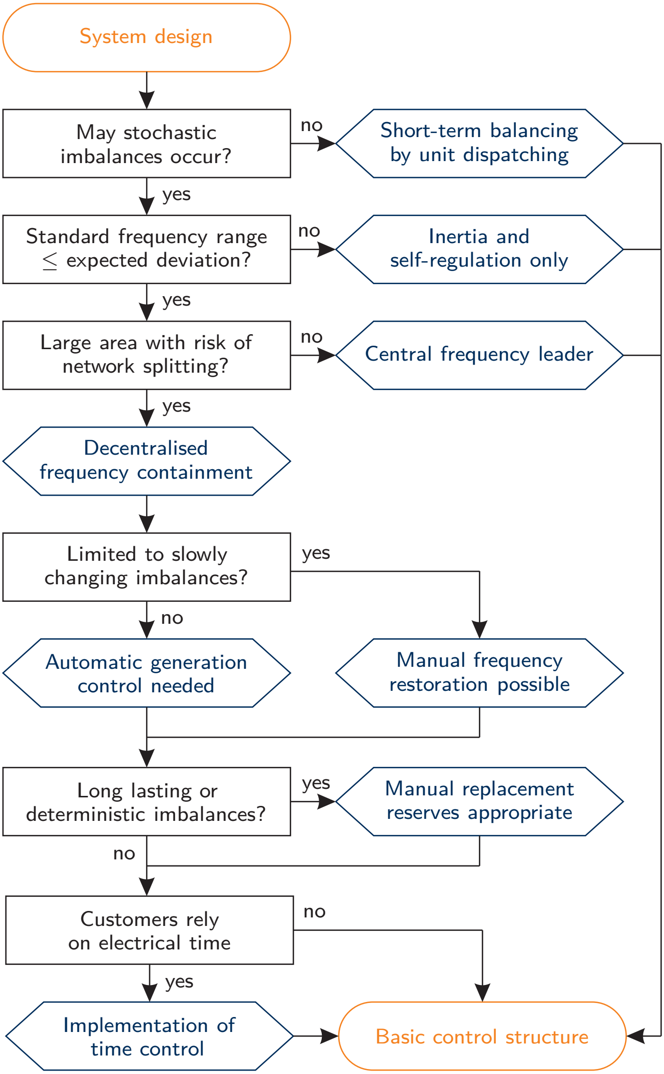


Figure 2.6.: Decision diagram for choosing an appropriate control structure. There are no standardised criteria that define such a setup: The diagram represents a qualitative decision-making framework.

are based on the fact that the quasi-steady state frequency is the same in the entire synchronous area [85,91]. Decentralised feedback, implemented by each control area to respond to the local imbalance, contributes to the overall balance in the system. Manual frequency restoration is rarely used in large systems. For example, the Northern European interconnected power system comprising Finland, Norway, Sweden and Eastern Denmark, used to deploy manually activated operational reserves for frequency restoration, but at the end of 2012 they implemented AGC in order to manage the deteriorating frequency quality [102]. However, smaller systems with larger standard frequency ranges such as Great Britain and Ireland rely on manual operational reserves for frequency restoration. In case of long lasting or well predictable imbalances, replacement reserves, i.e. reserves with a longer activation and a minimum deployment time such as non-spinning operational reserves, can be used to free up restoration reserves until the respective BRPs have compensated for their imbalance. Hence these reserves link frequency control and energy balancing. Time control is used if producers or network users rely on electrical time, i.e. an average frequency of 50 Hz.

As a large area comprising several countries, Continental Europe has chosen a four-level[20] control hierarchy which is obtained by following the longest path in Figure 2.6. Figure 2.7 gives an overview of the implementation of Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR), Replacement Reserves (RR), and time control. It illustrates the time sequence or chronology after a fault event.

Ancillary Services

In a liberalised market environment, frequency control requires the concept of ancillary services. Every auxiliary function necessary for operating a power system can be referred to as such: They span all voltage levels and are present along the entire value-added chain [89]. However, it is common to limit the term to centrally co-ordinated services. In the United States, the Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system" [81]. This definition suggests that these services are the responsibility of the TSOs,

[20] Often time control is not considered a separate level, as it is usually implemented by adjusting the AGC set point.

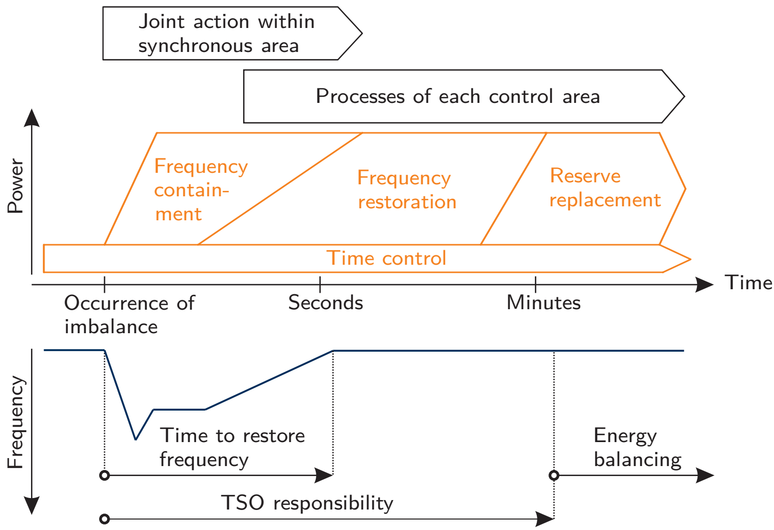


Figure 2.7.: The chronology of the four frequency control processes in a synchronous area and its control areas; in the context of classifying dynamics, frequency control is of usually slow phenomena, which take place in seconds to minutes.

as they operate the transmission system and co-ordinate the cross-border exchange between control areas. Hence frequency control in unbundled power systems is organised in the framework of ancillary services and the respective TSOs bear the responsibility for it.

Active Power Reserves

The associated resources, i.e. capacities, to accomplish frequency control are referred to as active power or control reserves[21]. Due to ownership unbundling, a TSO does not usually possess any generation or controllable load, but must have access to reserves; therefore, TSOs use market-based mechanisms for their acquisition [88]. A typical acquisition method for ancillary services in Europe is a tender for a given time period, for example, a month or a week. An overview of different setups for the acquisition of ancillary services, in particular frequency control, is given by Rebours et al. [114,115].

Inertia and Self-Regulation

The initial gradient of the frequency deviation is determined by the total system inertia of the system, both natural and synthetic[22]. Natural inertia is an intrinsic property and refers to the amount of kinetic energy stored and released by the synchronously connected rotating masses in the power system. Synthetic inertia is a function added to the system to obtain a similar effect from non-synchronously connected devices such as wind turbine generators. For a robust power system, the system frequency should not be overly sensitive to power imbalances. It is important that a large proportion of generation and load in a power system contributes to the total system inertia. Currently, inertia is considered system-inherent; however, as the share of rotating masses in power systems generally decreases, it might be necessary in future to purchase inertia within the framework of ancillary services.

Time Control Process

Frequency control is not limited in time and is carried out continuously. Furthermore, the nominal frequency f_0 is slightly adjusted in regular intervals according to the cumulated frequency deviation in order to sustain a constant average frequency of 50 Hz, and therefore, the long-term energy balance in the system. This process is referred to as time control or time error correction, as precise timekeeping can be derived from a constant average frequency, i.e. time control is meant to correct deviations between electrical time and Co-ordinated Universal Time (UTC, also used

[21] The term "operational reserves" is sometimes also used, but rather refers to both active and reactive power, i.e. resources for frequency control as well as voltage support.

[22] Alternatively referred to as artificial, emulated or simulated inertia.

as a backronym for Universal Time Co-ordinated). This service is essential for customers and equipment relying on the frequency for timekeeping. These are often legacy devices such as electrical meters, electric clocks, and electro-mechanical street light timers and controls.

As the instantaneous frequency is corrected to its nominal value after an incident without compensation of the accumulated energy mismatch, time control also sustains the long-term energy balance in the system: The energy for frequency containment, i.e. primary control energy, is not explicitly settled in Continental Europe, and the providers profit considerably from a zero average frequency and the respective planning certainty. The electrical time depends on the frequency (or voltage) time period, which is 20 ms for 50 Hz; thus, the instantaneous frequency f over a given time t determines the time error ϵ:

$$\epsilon = \int_0^t \frac{f - 50\,\text{Hz}}{50\,\text{Hz}} \mathrm{d}t \tag{2.2}$$

The time error is used for real-time monitoring and serves as a performance indicator. If the daily time error exceeds ± 20 s in the Continental European power system, the frequency set-point f^{set} is adjusted by the time correction offset f^{off}, i.e. $f^{\text{set}} = f_0 + f^{\text{off}}$, where f^{off} is ∓ 10 mHz for the whole next day. The activation dead band of frequency containment is also 10 mHz for time control to generally not trigger frequency-response reserves, since for those the frequency set-point usually cannot be adjusted. Time control is monitored and co-ordinated by one dedicated system operator ("time monitor") in the synchronous area. In normal operation, the target range for the maximum time error is ± 30 s. Time control is the only frequency control process that is not immediately triggered by a single imbalance.

Time to Restore Frequency

The time to restore frequency is a technical design parameter (not necessarily related to the imbalance period). Within this time, the frequency is meant to be restored after a single imbalance[23]. It is 15 minutes in the Continental European as well as the Nordic power system, 10 minutes in Great Britain and 20 minutes in Ireland. The time to restore frequency can be used to conclusively distinguish manual frequency restoration and

[23] It is assumed that a single imbalance does not exceed a pre-defined expected maximum instantaneous deviation, i.e. the reference incident. It is a variable with a negative (load exceeds production) and positive (load falls below production) value, one of which is usually the negation of the other.

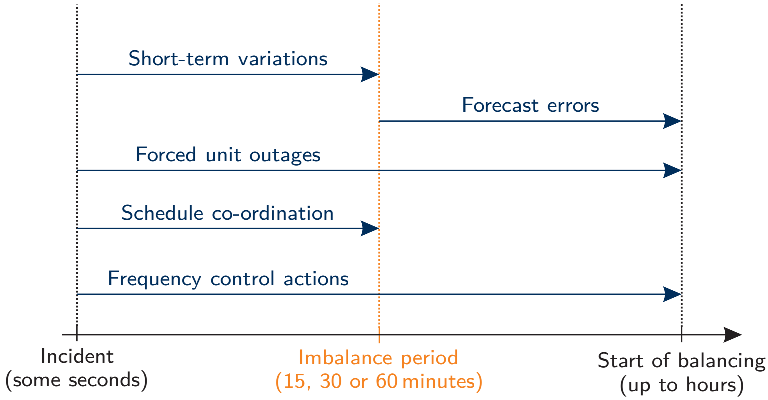


Figure 2.8.: Classification of possible imbalances in a power system; detailed modelling will be discussed in Section 4.2.

replacement reserves: Manually activated active power reserves with an activation time longer than the time to restore frequency are considered replacement reserves. The imbalance period as well as the time to restore frequency represent two important impacting factors that determine the overall energy balancing and frequency control behaviour. Moreover, there are several advantages in harmonising both, which will be investigated in Section 5.

Types of Imbalances

It should be noted that significant disturbances, such as an outage of a large power plant, are relatively rare (see Appendix B.2); most of the time frequency control corrects deviations of power exchanges from schedules between control areas, which do not necessarily have an impact on the security of the power system. In Figure 2.8, the various reasons for these deviations are distinguished by duration and influence time frame.

As indicated, the imbalance period is the defining parameter for all but forced unit failures. Short-term variations P_i^{stv} occur within an imbalance period T^{ibp}, whereas forecast errors P_i^{fce} are defined as the difference between scheduled set value per imbalance period $\bar{P}_i^{\text{set}}$ and average of the actual value over the imbalance period P_i:

$$P_i^{\text{stv}}(t) = \bar{P}_i(t) - P_i(t) \tag{2.3}$$

$$\bar{P}_i(t) = \frac{1}{T^{\mathsf{ibp}}} \int_{\tau_2}^{\tau_2 + T^{\mathsf{ibp}}} P_i(\tau_1)\, \mathrm{d}\tau_1 \bigg|_{\tau_2 = t - t \bmod T^{\mathsf{ibp}}} \tag{2.4}$$

$$P_i^{\mathsf{fce}}(t) = \bar{P}_i - \bar{P}_i^{\mathsf{set}} \tag{2.5}$$

The sign convention has been chosen such that a positive difference in Formula 2.3 and 2.5 corresponds to a shortage, whereas a negative amount corresponds to a surplus.

Short-term variations or noise are of a stochastic nature and can be caused by load or production. The same applies to forecast errors. Forecast error and short-term variation can apply to both a BRP and a TSO. For the latter, it is an aggregation of all the BRPs located in its control area. The forecast error changes with the imbalance period. The shorter the imbalance period, the higher the resolution of standard market products BRPs can use to cover their scheduled demand and production. A BRP can derive the same effect by either solely trading structured products OTC or performing a continuous unit commitment or demand-side management, which is possible if the BRP comprises load and production. This process is referred to as load-following, as it virtually links load and production[24]. Forced unit outages refer to non-disposable outages of power supplying elements in the power system. The schedule co-ordination involves all aspects of schedule changes. Their proper operational implementation, such as ramping constraints of power plants or the operation of ripple controlled devices, greatly influences the frequency quality. Therefore, P_i^{set} in Formula 2.5 does not necessarily equal values given by a schedule as defined in Section 2.3.2, as ramping requirements apply for both national and international schedules.

Frequency control actions may cause a mismatch for two reasons: Within the synchronous area, inaccurate control parameters, especially in regional frequency restoration and reserve replacement, or damaged equipment such as missing measurement or biased data gathering, may cause additional deviations instead of compensating the imbalance. Between synchronous

[24] Technically, this can also be achieved by open-loop controlling the net power exchange of a BRP; however, the respective BRP needs real-time measurements and generation capacity as well as the legal basis to do so. It should be noted that this may possibly interfere with the frequency control responsibility; at worst, it could provoke power oscillations in the power system.

areas, adjacent small power systems may rely on the non-synchronous interconnection as a frequency control resource and can carry over the frequency deviation to a larger system.

Ramping Restrictions

For trading and schedule-based supply of demand both trading volumes and the resulting schedules change discretely from one imbalance period to the next. Nowadays, these changes concentrate on the change of hour, as energy trading in Europe is dominated by hourly products. In the case that production and consumption correspond exactly to a step-shaped schedule pattern, both should change not only instantaneously but also simultaneously to ensure a continuous balance. This is neither physically reasonable nor technically feasible. In Continental Europe, the ramping period T^{ram} between TSOs has been set to 10 minutes[25] [104,106]. The choice of the minute value for the ramping period is arbitrary as long as it is unique in a synchronous area[26], and serves two aspects:

- The period has to be technically feasible for production units in the area, and the ramp should not be faster than the underlying load pattern. Technically, the ramping period is a trade-off between fast units such as hydro power plants and slow units such as coal-fired plants.

- The period has to be accepted by traders and considered in the unit commitment. Nowadays, most large schedule changes are a result of trading activity. The higher the traded volume and the overall schedule change, the more crucial it gets to have a common ramping period. This becomes obvious when imagining that even at a constant load level, market activities can lead to a shift in production of nearly any magnitude. This could lead to a mismatch between load and production of the same magnitude if the production units do not follow the same ramp-shaped progression.

In practice, the Continental European ramping period is only binding between TSOs. It has been defined to allow vertically integrated system

[25] The difference between schedule and operational implementation as a result of the ramped schedule is shown in Figure C.2.

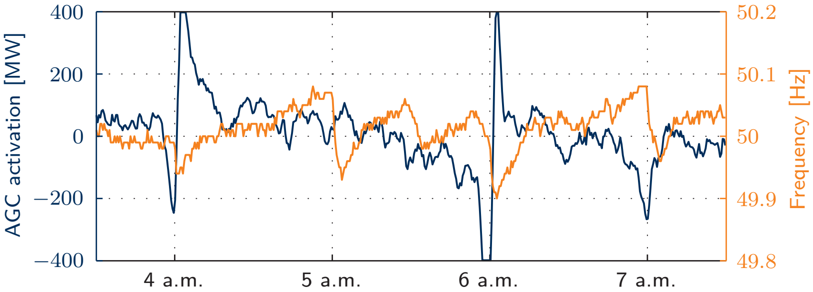
[26] The ramping restrictions on HVDC connections should also align to the connecting area ramping periods; however, HVDC links usually are restricted by ramp rates rather than ramping periods, which may also cause an inconsistency.

operators[27] to agree on an exchange programme or a Mutual Emergency Assistance Service (MEAS) long before liberalised market structures and the existence of BRPs. Schedule changes between control areas are to be implemented continuously over a period of 10 minutes instead in one discrete step, i.e. the linear set point change is to be considered for AGC. However, if the generating units of BRPs follow a discrete schedule change as fast as possible (physical ramp rate), TSOs have to compensate for the deviation between both constant schedule and continuously changing load as well as physical ramp and ramping period. Figure 2.9 illustrates these problems with the example of Switzerland during morning and evening hours. In the morning hours, load is typically rising almost linearly; Figure 2.9a shows how one or more BRPs covered such a load profile with hourly standard products, and the Swiss TSO had to compensate this zigzag-shaped mismatch with active power reserves. Irrespective of load, a schedule change can provoke large mismatches: Figure 2.9b shows an example of evening hours when BRPs followed a schedule change almost instantaneously. This resulted in a depletion of AGC resources, i.e. the BRPs did not adhere to the stipulated ramping period for cross-border exchanges between countries; and the frequency evolution emphasises the European-wide problem non-compliant schedule changes cause.

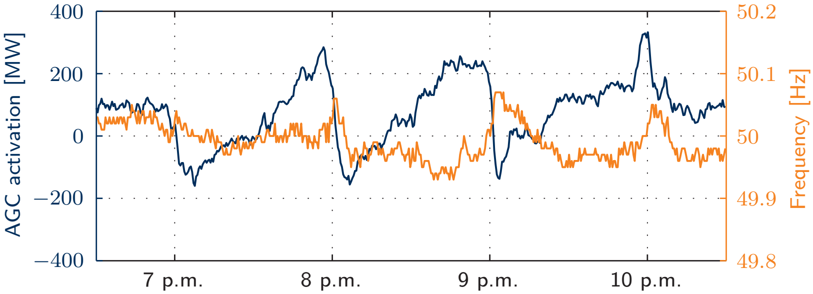
Consequently, the ramping policy between TSOs can be pushed further by national transmission codes or grid regulations. To the author's knowledge, only Swiss regulations have widened the scope of this regulation to include production and load changes of BRPs [140,142,143]. The BRPs have to ensure the changes in the schedules, which can be import or export, are implemented linearly with $T^{\text{ram}} = 10$ minutes to the extent that is technically reasonable (see Appendix C for a detailed example). In this way every schedule-based operated BRP has a clear planning basis for what ramp can be expected. Market transactions are not influenced by this rule, as the clearing of wholesale trades is carried out based on the price determined by wholesale trading. Figure 2.9c shows an example of successful operational implementation, i.e. the target progression of a change in the cross-border exchanges as a result of the ramped schedule and the corresponding minor deployment of AGC resources.

As a result, the schedules are no longer a suitable reference for calculating

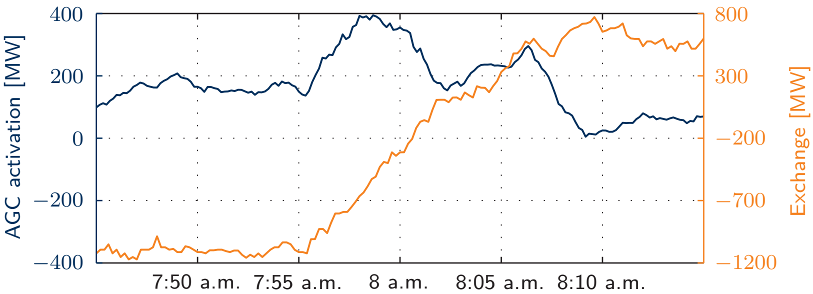
[27] Historically, there was no need for the role of a BRP, as vertically integrated utilities knew load and production profiles of preceding steps of the supply chain [147].



(a) Swiss AGC signal and European frequency on 11 January 2010, which show the typical deterministic imbalances due to non-compliant ramping of market participants.



(b) Swiss AGC signal on 10 May 2010, which illustrates the typical zigzag-shaped profile as a result of hourly wholesale products.



(c) Cross-border exchange on 8 September 2010, which demonstrates the need for operational ramping rules for schedules of BRPs.

Figure 2.9.: Examples taken from the Swiss power system in 2010; the situation in Figure 2.9a occurred before the incentive-based billing of imbalance energy, and Figure 2.9c shows a situation after its introduction.

the imbalance energy as introduced, as it is state-of-the-art in Continental Europe. If the schedules serve as a reference for imbalance energy, a BRP is incentivised to either follow the step-shaped schedule or announce a schedule that differs from the actually planned (stationary) power profile. The latter naturally applies to load-following utilities, as their schedule notifications are based on the expected average energy per imbalance period. But for trading and schedule-based operation of BRPs, it is a matter of money that the imbalance energy calculation considers the operational ramping. To obtain a proper reference P_i^{set} per imbalance period for the imbalance energy as introduced in Formula 4.9, the schedule values P_i^{sc} have to be corrected such that

$$\begin{aligned}\bar{P}_i^{\text{set}} &= P_i^{\text{sc}} - \underbrace{\left(\frac{P_i^{\text{sc}} - P_{i-1}^{\text{sc}}}{8 \cdot \frac{T^{\text{ibp}}}{T^{\text{ram}}}}\right)}_{\substack{\text{ramp correction for} \\ \text{previous period}}} - \underbrace{\left(\frac{P_i^{\text{sc}} - P_{i+1}^{\text{sc}}}{8 \cdot \frac{T^{\text{ibp}}}{T^{\text{ram}}}}\right)}_{\substack{\text{ramp correction for} \\ \text{next period}}} \\ &= P_i^{\text{sc}} - \left(\frac{T^{\text{ram}} \cdot (P_{i-1}^{\text{sc}} + 2 \cdot \bar{P}_i + \bar{P}_{i+1})}{8 \cdot T^{\text{ibp}}}\right).\end{aligned} \tag{2.6}$$

It is worth mentioning that the introduction in Switzerland led some BRPs to compensate the energy difference of the ramping in order to still follow the step-shaped schedule [155], which contradicts the original intention, as the calculation of $\bar{P}_i^{\text{set}}$ does not affect the scheduling of the BRPs. Introducing $\bar{P}_i^{\text{set}}$ in addition to P_i^{sc} only affects the rule for calculating the imbalance energy. The TSO calculates the difference in energy due to the ramping on the basis of the schedule values and takes these into consideration in the billing of the imbalance energy. Mathematically speaking, the inclusion of the ramping requirement implies smoothing the schedule. Figure 2.10 illustrates an example.

Post Scheduling

If foreseen in national regulations, the BRPs can also make use of post scheduling on a market platform without direct TSO involvement: A BRP, whose physical feed-in differs from the formerly announced amount, can find a counterpart which is imbalanced itself, but in the opposite direction, i.e. post scheduling allows for ex post imbalance sharing. Thus, schedules can be changed or newly registered, and post scheduling offers the possibility to adapt schedules to measured values after real-time operation for accounting purposes. This is used to adjust a BRP's schedule due to

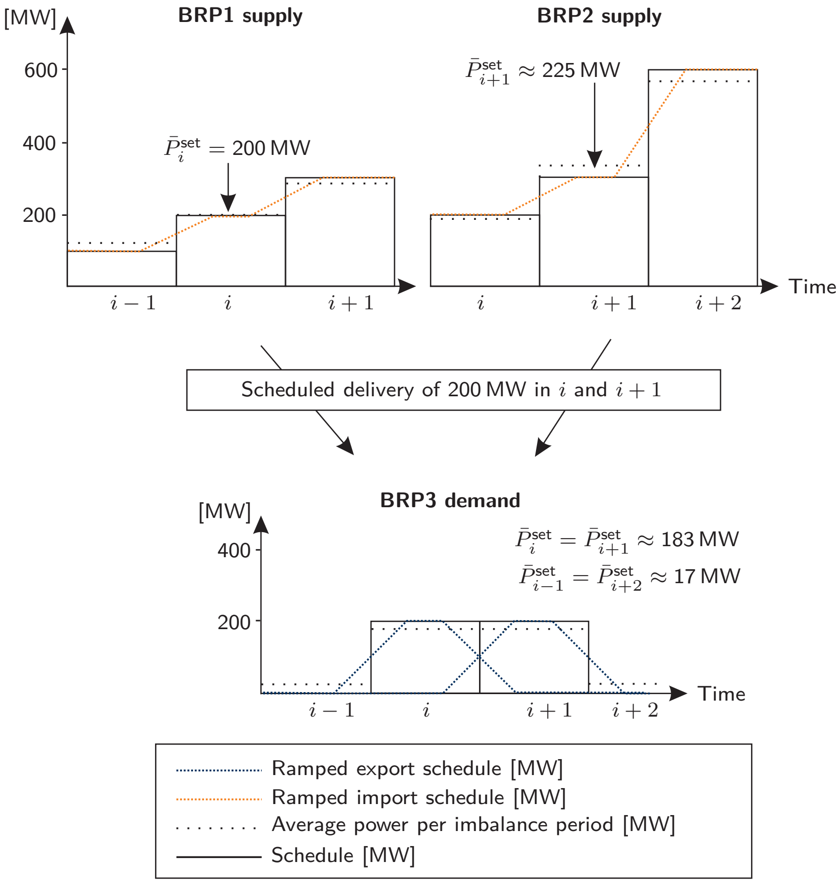


Figure 2.10.: An example to illustrate how ramping affects the net energy per imbalance period. In general, the average of the ramped schedules differs from the discrete trading schedules, and the imbalance energy is calculated on that basis. Ramped schedules meet continuous load profiles more precisely and can physically be realised by production of different technology portfolios.

the delivery of active power reserves[28] from a providing unit whose metering points are assigned to that BRP[29], i.e. post scheduling is performed between BRPs and TSO.

Post scheduling usually takes place on the working day following the day the schedule applies to. This can also apply to situations in which a BRP could not announce a short-dated OTC trade, for example, in case of providing energy for the compensation of power plant failure in another BRP in order to avoid or counteract an imbalance in the control area. Obviously, post scheduling can only be done for internal trading in a control area, as the TSO manages the imbalance of a control area in real-time. Internal trading does not change the exchange between control areas, but the imbalance energy the BRPs have to pay.

2.4. Preconditions for Pan-European Centralisation

After outlining the basic framework for matching demand and production, a brief discussion is given of the general interactions between the main roles in a liberalised market environment, which have been introduced in the last two sections. A typical example taken from the Swiss power system illustrates the strong interdependence between the financial incentives of those actors and the impact that wholesale trading can have on system security. Operational and contractual measures for coping with potential loopholes are briefly discussed and the aspects which will need to be considered in future regulations for the electricity sector are elaborated.

2.4.1. Roles and Responsibilities

Figure 2.11 illustrates the main actors in unbundled electricity market environments. The net flow of electricity, i.e. electric energy, runs along the three technical domains of generation, transmission, and distribution, whereas the net financial flow can be branchier and more complex. The term net flow has been chosen to account for negative prices and distributed

[28] Except for the frequency-triggered deployment of FCR for which the BRPs do not receive any settlement in Europe.

[29] This implies a contractual agreement between the two legal entities, i.e. BRP and the operator of the providing unit.

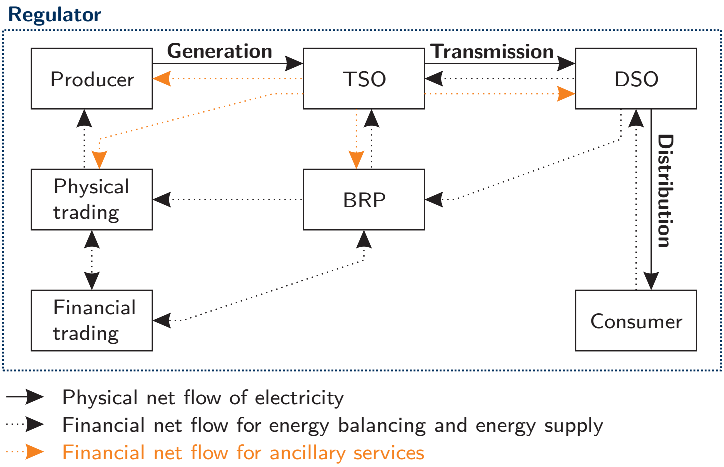


Figure 2.11.: Simplified overview of the actors and roles in a liberalised market environment in a country or control area (figure inspired by [153]).

variable generation that can temporarily invert both financial and physical flow.

The roles as shown in the figure are necessarily neither a legal entity nor represented by a single company. This is obvious for the example of trading (see Figure 2.4), but also to be taken into account for cascaded DSOs and energy suppliers. The latter in particular are always affiliated with a BRP but usually constitute separate companies[30]. Moreover, a TSO can have end-consumers as well such as large-scale industrial plants or train systems; however, those most likely are also separate BRPs.

The financial flows originating from the acquisition of ancillary services trace back to the TSO. Depending on type and purpose, an ancillary service can be acquired on a wholesale market (for example, compensation of active power losses), via a BRP[31] (for example, active power reserves), or from generating companies and DSOs (for example, black-start capability, voltage support, metering services).

[30] There can be individualised, i.e. non-standardised, contractual and operational frameworks between a BRP and the DSOs as well as energy suppliers whose metering points are assigned to that BRP.

[31] In this case, and from a legal point of view, the BRP is also an Ancillary Service Provider (ASP) or Balancing Service Provider (BSP).

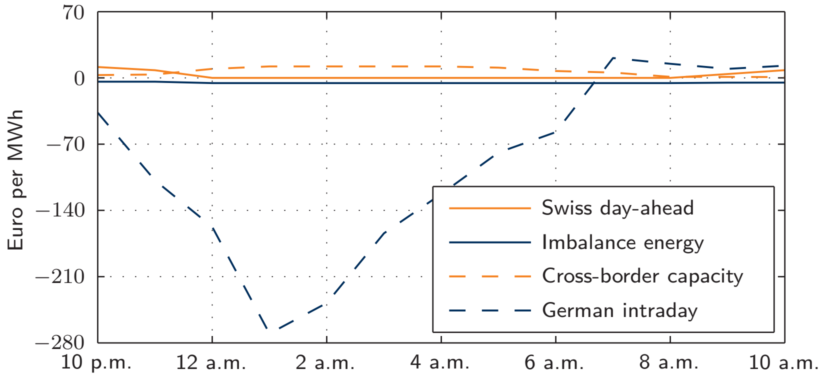


Figure 2.12.: An incident which occurred in 2012 and caused physical imbalances of up to 700 MW.

Figure 2.11 also visualises the administrative difficulties and operational challenges that come along with centrally co-ordinated ancillary services that are implemented by means of demand-side management. There is no direct link between a TSO and an end-consumer in a distribution system; in between, there are a BRP, at least one DSO and most likely several energy suppliers, which makes additional management and settlement processes inevitable [152].

Case Example

Section 2.3.3 already highlighted the impact of market-induced frequency deviations due to hourly products on wholesale electricity markets. To illustrate another potential physical challenge to system security by trading in an unbundled market, a historical example that occurred end-2012 in the Swiss power system is presented. The ex post analysis of this incident made evident that this had not been a coincidence but rather a consequence of the price setup between international wholesale markets and the domestic imbalance pricing mechanism.

The incident occurred when several traders had large open positions at the same time, which means there was no demand for the energy produced. Figure 2.12 shows the prices of the Swiss spot and the German intraday market as well as the Swiss imbalance energy and the day-ahead cross-border capacity. For the early morning hours, which are typical base load hours, the already low Swiss spot price converged to zero. At the same time the intraday market price in Germany was strongly negative, as there was a large amount of energy offers due to intermittent infeed. During these hours, several BRPs of traders (without load or production responsibility) had large open positions. These traders were not able to sell their energy on the Swiss spot market, and they did not take actions to sell the energy in the German intraday market at a negative price. As the imbalance energy price in Switzerland remained positive, they made a profit: In retrospect, they even had a clear incentive to accept these open positions. This situation caused a physical power deviation of up to 700 MW for eight hours in the Swiss control area. Together with regular forecast errors by load supplying BRPs this imbalance summed up to roughly 1 GW. Such an imbalance surpasses the active power reserves contracted by the Swiss TSO, as those reserves are dimensioned only for forecast errors and forced unit outages.

For a detailed discussion of distorted trading incentives and respective remedies in Switzerland, a detailed analysis is presented in Appendix A. This shows the practical impact and the theoretical potential of imperfections in an imbalance pricing mechanism.

2.4.2. Future Policy Implications

National Level

The analysis of the Swiss system showed that the local market design can have a strong impact on the matching of demand and production, i.e. energy balancing and frequency control (see Appendix A). The national matching framework, in particular the imbalance pricing mechanism, on the one hand has to provide strong incentives to BRPs to be balanced, and on the other hand support TSOs via operational implementation rules for scheduling. On a European level, the design of an adequate and harmonised imbalance pricing mechanism as the link between trading and system security can be considered as the very core challenge for future rules and regulations.

European-Wide Regulations

The financial crises in 2008, and the American "Dodd-Frank Act" in particular, gave rise to several new regulations for financial markets such as REMIT, EMIR, MiFIR, and MAR. However, they do not deal with energy balancing and imbalance pricing, but affect the electricity sector as they cover data reporting as well as national reporting requirements and have to be duly considered for drafting the Network Codes. The purpose of the latter is to set up European-wide rules for the harmonisation of electricity markets and system operation: They aim at providing effective and transparent access to the transmission systems across national borders. Drafting of these codes began in 2010, while the number and precise scope had not been predefined; “Regulation 714/2009/EC” only sets out the areas in which these codes will be developed and a process for developing them [62]. As these codes will constitute the future regulations for energy balancing and power system operation, particular attention should be paid to the impact of harmonising cross-border regulations on local energy balancing and its national imbalance pricing mechanism.

On the one hand, the “3rd energy package” stipulates a competitive and integrated European electricity market with extensive cross-border trade facilitation. The implementation of the corresponding “Network Code on Capacity Allocation and Congestion Management” already started at a regional level with the gradual integration of regional initiatives [44]. For example, in February 2014 the CWE region was successfully coupled with the Nordic countries resulting in the so-called North-Western Europe (NWE) day-ahead market coupling. Hence market participants’ access to new markets is gradually being facilitated. On the other hand, the future generation mix according to the European Union’s 20-20-20 targets will be characterised by an even higher amount of intermittent generation than today. These developments lead to volatile electricity prices caused by unpredictable infeed, and therefore, to continuously occurring stochastic imbalances. The significance of intraday markets will increase on both a national and cross-border level. However, system-destabilising trading is, among other factors, subject to the interaction between national imbalance pricing mechanisms and neighbouring wholesale market rules, i.e. cross-border day-ahead and intraday trading.

The “Network Code on Electricity Balancing” aims to promote a higher degree of co-ordination and integration of European balancing markets [49]. According to its regulations, market participants shall generally support system security, and more specific settlement principles for imbalance energy shall take into account interdependencies with intraday and day-ahead markets. Additionally, the code requires the definition of common principles for the procurement of balancing capacity and balancing energy “to ensure that distortions within the internal market and in particular between adjacent markets are avoided” [49]. Nonetheless, the crucial issue of aligning cross-border wholesale electricity market activity and national balancing pricing mechanisms at a European level is approached only at a high level. For example, the code claims that two TSOs are enough to form a co-ordinated balancing area. Hence the harmonisation of pricing rules has to take place only between those two TSOs; adjacent markets are not taken into consideration. Obviously, the current development of the "Network Code on Electricity Balancing" deals with a wide range of cross-border network and market integration issues, whereas imbalance pricing mechanisms are dealt with at a national level.

The "Network Code on Load-Frequency Control and Reserves" aims at defining transparent and harmonised prerequisites for transmission system operation in order to ensure operational security, i.e. frequency quality, and to contribute to the efficient functioning of the European electricity market [47]. It defines a common set of minimum requirements with regard to operational rules, quality criteria and targets, reserve dimensioning, reserve exchange, sharing and distribution as well as monitoring. The "Network Code on Load-Frequency Control and Reserves" forms the future basis for the cross-border co-operation between TSOs on an operational level. It only outlines general concepts without stipulating a European-wide approach to co-operation, or a potential centralisation to maximise synergies. Instead, it leaves the choice to local TSOs and respective local initiatives and political ambitions. Therefore, the following chapter details general concepts for a European-wide centralisation of frequency control.

3. Steps Towards the Centralisation of Frequency Control

This chapter outlines the methods for modelling frequency control structures in Europe. It discusses the different approaches and possibilities towards a stepwise centralisation of control actions across countries and proposes subsidiary measures for harmonisation. The objective is twofold: to reduce control actions as well as control resources. The control structures for AGC are outlined and a reduced synchronous area model is derived that makes use of multi-objective optimisation in order to consider transfer capacity limitations between control areas.
Parts of this chapter have been published in [121,124,128,130].

3.1. Modelling Approach

The objective of this thesis is to investigate different levels of centralisation of frequency control structures and their performance under current and expected future conditions. Section 2 showed that the frequency control structures, i.e. the control processes implemented in a synchronous area, are a deliberate choice fixed by national and international regulations. In this context, the next three chapters are organised as follows: Section 3 deduces a reduced synchronous area model, elaborates concepts to centralise frequency control actions, and discusses methods for standardising active power reserve dimensioning as well as control parameters. Section 4 defines scenarios as well as input data which allow modelling area-specific imbalances. The results of simulations using both the concepts elaborated in Section 3 and the imbalance modelling derived in Section 4 are presented and discussed in Section 5.

3.2. Derivation of a Reduced Synchronous Area Model

In this section, the reduced synchronous area model is derived. The basic control structure is an output of the decision diagram in Figure 2.6 (see Section 2.3.3). The diagram illustrated the reasoning behind a multi-tiered approach for frequency control. The congestions relevant to frequency control have been discussed in Section 2.3.2. In a control area, it lies within the responsibility of the national TSO to manage any internal congestions and choose the reserve providing units. Between congested areas, the imbalance can be allocated to the extent of the available transfer capacity. By doing this, is is possible to model a reduced synchronous area which needs a control structure and imbalance modelling as input. As the presence of transfer capacity congestions is independent of the control structure, the imbalance modelling and the parametrisation of the control structure can be done simultaneously.

3.2.1. Requirements

In order to derive a mathematical description of a reduced synchronous area model, the requirements are outlined. There are generally four prerequisites for the model:

Irrespective of multiannual plans: In the course of investigating possible future power production and electric load structures, different scenarios are being developed, which are driven by the energy transition discussion in particular. They vary strongly from country to country and range from the creation of an energy system based on 100 % decentralised renewable energy to a resumption of centralised nuclear energy sources. However, the frequency control setup needs to be independent of technical and political scenario planning and evolvements.

Applicable to variations in market design: Similar policy goals and exogenous conditions resulted in comparable chronological and liberalised market structures in Europe (see Section 2.3.2), and robustness against existing and future variations in market design is a prerequisite for a large-scale model. This thesis covers European market structures, i.e. uniform and zonal pricing. Fundamentally different market concepts such as Locational Marginal Pricing (LMP) are no longer discussed[1]. Note, however, that the discussed zonal concepts could also be customised to fit a nodal structure.

Compatible to transfer capacity calculations: There are different ways to calculate cross-border capacity. Nowadays, the most common method for determining the cross-border capacity between countries are the ATC mechanism and the flow-based methodology.

Executable in real-time operation: Frequency control is a matter of minutes, and the model needs an adequate implementation that would allow real-time application. A secure and robust programming that is largely immune to miscomputation and model instability is desirable. It should also be time-invariant, as the frequency control output should not depend specifically on time, i.e. it needs to be transparent from a regulatory point of view in order to grant model conformability and traceability.

3.2.2. Frequency Dynamics

To analyse the different control structures, an appropriate frequency model is needed. A decentralised AGC structure serves as a starting point for discussing future changes, and a frequency control model is derived which closely follows the models presented by Andersson [5] and Kundur [91]. Note that since short-term phenomena such as power plant dynamics and small-signal frequency swings are not significant for AGC, the modelled power system shares one common frequency and employs only first-order delays as power plant models [85].

Frequency Restoration Responsibility

Figure 3.1 shows the control diagram of the Continental European four-level control hierarchy from a bottom-up perspective. The frequency restoration responsibility is shared among N control areas by means of AGC,

[1] Although LMP is state-of-the-art in the United States [134], the practical feasibility for Europe until 2030 is considered to be rather unrealistic. Regional and (economic) distributional effects which influence the competitiveness of electricity-intensive industries, and therefore, the level of employment are assumed to prevent a practical implementation [23]. Furthermore, reducing market areas to nodes could decrease market liquidity, and recent studies showed limited economic benefit of nodal pricing in Europe [23,73,101].

where a disturbance δ can originate in each area i. Decentralised feedback, implemented by each control area for responding to the local imbalance, contributes to the overall balance in the system. The Area Control Error (ACE) is the sum of the weighted frequency deviation Δf and the deviations of the net tie-line flow ΔP_i between the control area i and its neighbours j:

$$ACE_i = \underbrace{\sum_{j\in\Phi_i}\left(P_{ij}^{\mathsf{phys}} - P_i^{\mathsf{set}}\right)}_{\Delta P_i} + K_i \underbrace{\left(f^{\mathsf{phys}} - f^{\mathsf{set}}\right)}_{\Delta f}. \tag{3.1}$$

The set Φ_i consists of all areas connected to area i which is meant to be controlled to the set value P_i^{set}. It is worth noticing that the term $K\Delta f$ can be seen as a virtual tie-line. The term "virtual" is used in ENTSO-E terminology to distinguish the calculated part of the ACE from physically measured tie-lines. The ACE is the control error for a PI controller (with anti-wind-up); its control signal P^{AGC} is sent to reserve providing units, which deploy the respective amount of FRR:

$$P_i^{\mathsf{AGC}} = \underbrace{-\left(C_i \cdot ACE_{\mathsf{i}} + \frac{1}{T_i}\int ACE_i \,\mathrm{d}t\right)}_{\text{PI controller}}. \tag{3.2}$$

Typically, the proportional term $C_i \in [0, 0.5]$ and the integral term $T_i \in [50\,\mathsf{s}, 200\,\mathsf{s}]$. If the frequency bias factor K_i is chosen appropriately, a control area will only compensate for its imbalance, and it will neither counteract its FCR contribution nor its share of self-regulation; vice versa, AGC will compensate for a non-delivery of FCR in the respective area [106]. This principle is referred to as non-interactive control, but opposite AGC activations between two or more areas are possible. Note that the manual frequency restoration and reserve replacement process are identical from a control point of view; thus, manual reserves are generally referred to as RR in this thesis in order to avoid confusions.

System Dynamics

System behaviour can be modelled by the total inertia dynamics H^{tot}, which comprises all inertial constants, and the total self-regulation D of the system. The dynamics of both are important for detailed frequency analyses, in which the effect of FCR is of interest. This dynamic model is discussed further in Appendix B.1. For analyses with a large time horizon, which focus on FRR and RR, the model can be simplified in order to reduce

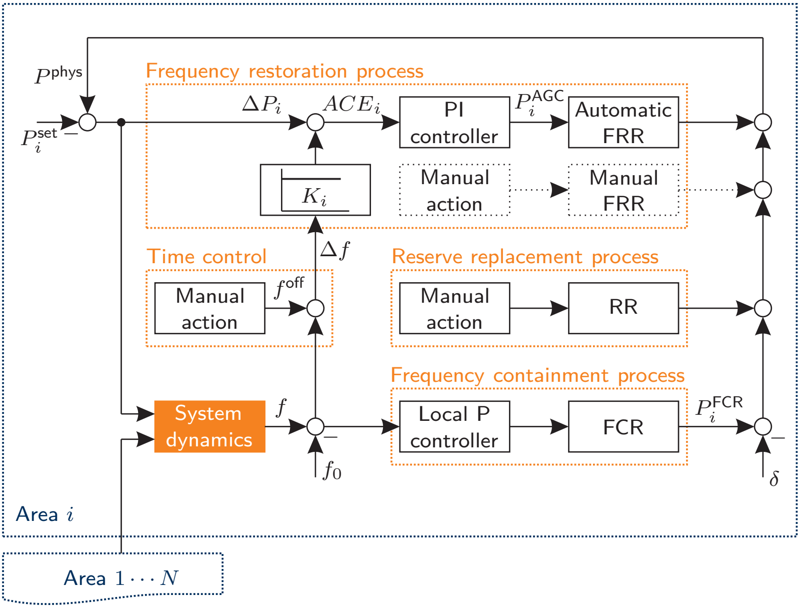


Figure 3.1.: The basic control diagram in a system with a four-level hierarchy of frequency control from a TSO perspective.

computational efforts. Figure 3.2 shows the system dynamics with summed up FCR and FRR. Thereby, Formula 3.1 is reduced to a power imbalance which can be described by the total K-factor, i.e. $\Delta P = K\Delta f$. Without AGC, i.e. $P_i^{\mathsf{FRR}} = 0$, ΔP is determined by the system dynamics and FCR such that

$$\Delta P(s) = \Big(\frac{2H^{\mathsf{tot}}S_{\mathsf{B}}}{f_0}s + D_l\Big)\Delta f(s) - P^{\mathsf{FCR}}, \tag{3.3}$$

where S_{B} is the total rated power and s the Laplace transformation variable. In steady state, ΔP is determined by FCR and self-regulation such that

$$\Delta P \approx \beta\Delta f, \tag{3.4}$$

where β is the frequency-response characteristic describing the total effect of (procured and additional) FCR and load self-regulation. The aim of a synchronous area's bias factor K is to fully compensate for the initial frequency-response, which can only be achieved if $K = \beta$. As K is the superposition of K_i, the subsequent aim of a control area's K-factor K_i is to fully compensate for the initial frequency-response, which can only be achieved if $K_i = \beta_i$. Moreover, it can be shown that independent of the choice of K_i, the frequency deviation will eventually be returned to zero; thus, the choice of K_i is not too critical for the system to work at all. However, as FRR are typically procured on markets, an area which can dimension its controller better will be able to reduce its financial expenditure. This will also allow for a more accurate approach to sharing imbalances or reserves between areas. Therefore, different approaches to improving the calculation of K are outlined in Section 3.4.1.

Figure 3.2 summarises the reduction of the frequency dynamics. Figure 3.2a shows the reduced synchronous area model with summed up FRR and FCR, whereas Figure 3.2b depicts an example step response to a 1500 MW outage for a dynamic and a reduced model. As can be seen, the reduced model is inaccurate below one minute but useful for longer time periods, for example, for investigating frequency control resources, i.e. FRR, RR, and the resulting frequency quality. The simplifications mainly affect the first seconds of a response. The dynamic model is suitable for more transient analyses such as non-linear K-factors, as discussed in

Section 3.4.1, or frequency-response coupling, as discussed by the author in [126].

3.2.3. Transfer Capacity Handling

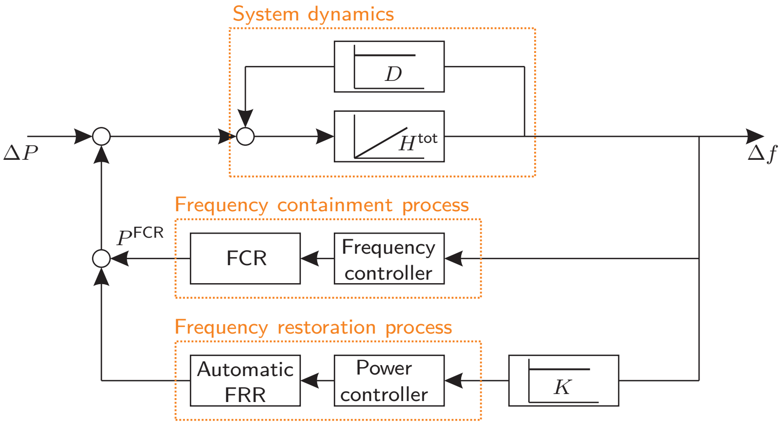
Centralisation of frequency control is limited by the availability of transfer capacity, and the reduced model has to include a respective logic to handle this. Market activity determines the planned load flows within and between price areas. Within a control area, the TSO is responsible for managing internal congestions to avoid them, or to resolve them through operational redispatch measures in order to guarantee that the physical flows resulting from market activity can actually be carried out. Thus, the network of the synchronous area can be reduced to a zonal model that only considers the congestions between areas. That justifies the assumption that control area internal congestion management is handled outside the scope of frequency control. That means that it is just the network topology between the control areas that is of interest.

Transfer Capacity

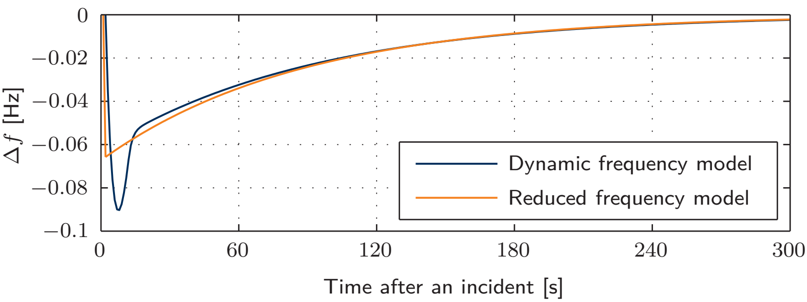
For mathematical modelling of a reduced model that satisfies the requirements outlined in Section 3.2.1, a synchronous area S consists of a set of control areas A and a set of net tie-lines T, i.e. $S = (A, T)$. Physically, a net tie-line is undirected, as the transfer capacity can be used to transmit the full nominal power in either direction; thus, the net tie-line could be modelled as an unordered pair of distinct areas i and j in A, i.e. a net tie-line between areas i and j can be denoted as $\{i, j\}$ or $\{j, i\}$. As the available transfer capacities generally differ due to congestions according to the direction of the power flow, each tie-line $t \in T$ is better modelled as an ordered pair of distinct areas i and j in A. To capture the relationship between A and T, let $\boldsymbol{B}^{\text{tie}} = (b_{ij}^{\text{tie}})$ be a binary $n \times m$ matrix of S ("tie-line incidence matrix") whose n rows correspond to the n areas in A and the m columns correspond to m net tie-lines in T with $1 \leq i \leq m$ and $1 \leq j \leq n$ such that

$$b_{ij}^{\text{tie}} = \begin{cases} 1 & \text{if there is tie-line capacity } j \text{ from area } i \\ -1 & \text{if there is tie-line capacity } j \text{ to area } i \\ 0 & \text{otherwise.} \end{cases} \tag{3.5}$$

For each $(i, j) \in T$, let c_{ij} be the transfer capacity with a lower bound of zero such that $\boldsymbol{C} = (c_{ij})$. This transfer capacity, that can be used in



(a) System behaviour under inertia dynamics and the self-regulation from a system perspective, i.e. with a pooling of the control processes.



(b) Example of a frequency behaviour for different simplifications of the system dynamics after a loss of 1500 MW, i.e. half the ENTSO-E reference incident; $H^{\text{tot}} = 12\,\text{s}$ and $D = 1.5\,\%/\%$, both typical values for Continental Europe according to [104].

Figure 3.2.: Reducing the frequency dynamics of a synchronous area.

the framework of frequency control, is the capacity that remains available after the final phase of the allocation procedure for commercial trading, i.e. the closing of the intraday market, for example, the ATC which is NTC minus AAC or the RAM in case of a flow-based allocation of cross-border capacity.

Types of Imbalances

An imbalance P_i^{imb} can occur in each area $i \in A$. Therefore, let $\boldsymbol{P} = (P_i^{\text{imb}})$ be a vector of dimension n whose elements correspond to the n areas in A such that there are three types of areas:

- The first type exhibits a surplus in power, and such an area i has an imbalance $P_i^{\text{imb}} > 0$.
- The second type exhibits a shortage in power, and such an area i requires a net amount of power $|P_i^{\text{imb}}|$ to be balanced where $P_i^{\text{imb}} < 0$.
- The third type of area is balanced; it does not require any power and so $P_i^{\text{imb}} = 0$. Such an area can serve as a transshipment area that a power flow can go through.

To describe the relationship between imbalances $\boldsymbol{P}$ and areas A in the zonal model, let $\boldsymbol{B}^{\text{imb}} = (b_{ij}^{\text{imb}})$ be a binary $n \times n$ matrix ("imbalance incidence matrix") whose n rows correspond to the n areas and whose n columns correspond to n virtual tie-lines for imbalance reallocation with $1 \leq i \leq n$ such that

$$b_{ii}^{\text{imb}} = \begin{cases} 1 & \forall i \in A \mid P_i^{\text{imb}} > 0, \\ -1 & \forall i \in A \mid P_i^{\text{imb}} < 0. \end{cases} \tag{3.6}$$

Implicit Assumptions

It has to be borne in mind that this modelling of a multi-area system is subject to implicit assumptions that neither limit its applicability nor mean a loss of generality:

- HVDC connections between control areas within the synchronous areas are part of the set of tie-lines T as they can also be used for frequency control services; however, the technical implementation of the respective virtual tie-line may require additional effort as HVDC connections are not always considered in the AGC boundary integral.

- A cross-border exchange to adjacent synchronous areas, i.e. the presence of back-to-back HVDC terminals or sub-marine HVDC cables, is assumed to be considered in the vertical load of the area in which the exchange is physically conducted. The reasoning is that such a connection is controllable. Its behaviour is more similar to a load (or generator) than to a tie-line interconnection, and this weak dependence classifies the connecting system as a single-area system that can be considered physically and operated independently.
- In general, $\sum_{i \in A} P_i^{\text{imb}} \neq 0$ as a power equilibrium is not likely to occur spontaneously: neither when the net multi-area system imbalance is calculated with $P_i^{\text{imb}} = ACE_i$, which can be used to determine the system frequency $\Delta f = \sum_{i \in A} ACE_i \cdot K_i$, nor when the total demand for active power reserves in the synchronous area is calculated with the open-loop ACE such that $P_i^{\text{imb}} = ACE_i^{\text{ol}}$.

3.3. Gradual Centralisation of Local Control Processes

Range of Influence

After elaborating the frequency dynamics and the handling of tie-line capacities, the different concepts of centralisation are presented in the following. These concepts will be analysed and compared in Section 5. The reserve capacities co-ordinated and available to the TSOs can gradually be centralised, whereas FCR are already fully shared reserves. Furthermore, a change in the geographical allocation of control structure and areas is not expected to influence the network power frequency characteristic, and therefore, the amount of FCR [104, 106]. This is reflected in the way the amount of FCR has been determined. In the power system of Continental Europe 3000 MW of FCR[2] must be deployed by a frequency deviation of 200 mHz. i.e. the design criterion of the maximum steady state frequency. As a consequence, the amount of FRR and RR can be structured separately, and the overall structure of FCR is assumed not to be affected by an integrated pan-European frequency control approach while the impact on the

[2]This upper limit originally referred to a simultaneous outage of two large units (load or production) of around 1500 MW ("double block failure") [7,159]. It is noteworthy that this approach has remained unaltered even after the connection of Turkey to the Continental European power system in 2010.

geographical distribution of FCR, for example, due to market conditions, is not investigated any further.

Types of Reallocation

For the active power reserves currently managed by local TSOs, namely FRR and RR, two basic approaches of centralisation can be followed in a congested system:

A priori imbalance reallocation: To decrease the deviation that needs to be compensated by reserve resources, imbalances can be reallocated in the system in order to reduce the local deviations, i.e. the control structure is enhanced by a distribution logic without necessarily changing the control structure. Therefore, an a priori imbalance reallocation refers to methods that reduce the control error.

A posteriori imbalance reallocation: To increase the availability of reserve resources, they can be rerouted to compensate a local deviation elsewhere. This can be done through changes in the control structure or by adding a control distribution logic which refers to reserve sharing. Therefore, an a posteriori reallocation refers to methods that increase the range of the control action.

3.3.1. A Priori Reallocation: Imbalance Sharing

As illustrated by Figure 3.1, the traditional non-interactive control principle allows opposite AGC activations between two or more areas in a synchronous area. As a first step, these opposing activations can be mostly avoided. This requires the introduction of a centralised imbalance reallocation logic. There are two comparable local concepts implemented in real-life system operation. A regional implementation of a so-called imbalance netting has been launched in Germany and its neighbouring countries [163]. Within Germany, the AGC coupling has been further expanded so that the four control areas have merged all active power reserves, which is referred to as German grid control co-operation [66]. With its neighbours, the imbalance netting takes place in sequential order according to a predefined custom-made hierarchy. A concept similar to imbalance netting has been implemented in the United States and is referred to as Area Control Error Diversity Interchange (ADI), which was originally proposed for control areas in North America [103]. The ADI concept can be reformulated using a two-step linear programming approach to consider congestion constraints [162]. Unlike imbalance netting, ADI does not include the activated AGC resources; its input is equal to the ACE without imbalance netting.

The idea of imbalance sharing is to extend the AGC principles to avoid counteracting FRR activations. Deviations of cross-border exchanges from scheduled deliveries are not compensated for as long as there is an area whose imbalance can be compensated by that deviation.

Extended Flow Problem

The problem of imbalance sharing can be solved by multi-objective programming and is subject to linear constraints on its variables. With the notation introduced in Section 3.2.3, it can be formulated as a non-linear programme with three objectives:

Step 1: Maximise the imbalance sharing ω^{imb} in order to reduce the imbalances in all areas.

Step 2: Minimise the usage ω^{tie} of tie-line capacities to avoid redundant assignment of transfer capacity.

Step 3: Minimise the distribution costs ω^{dis} between surplus and shortage areas.

First, the imbalances P_i^{imb} are to be adjusted in such a way that the overall imbalance in the synchronous area S is minimised. Therefore, let x_i^{imb} be a vector of dimension n that contains the decision variables representing the amount of a power to be reallocated to another area; thus, **Step 1** can be formulated as:

$$\text{maximise} \quad \omega^{\text{imb}}(x_i^{\text{imb}}), \tag{3.7}$$

where each decision variable x_i^{imb} is bounded with lower bound 0, and upper bound P_i^{imb}. Second, the tie-line capacities used for the power reallocation have to be minimised to avoid unnecessary flows and to keep as much capacity available for additional ancillary service-related actions such as reserve sharing or a MEAS as possible. Therefore, let x_{ij}^{tie} be a vector of dimension m that contains the decision variables representing the additional flow on the tie-lines. For **Step 2**, this yields:

$$\text{minimise} \quad \omega^{\text{tie}}(x_{ij}^{\text{tie}}), \tag{3.8}$$

where each decision variable x_{ij}^{tie} is bounded with lower bound 0, and upper bound c_{ij}. Third, the surpluses and shortages are distributed according to a defined distribution function, and **Step 3** can be formulated as:

$$\text{minimise} \quad \omega^{\text{dis}}(x_i^{\text{imb}}). \tag{3.9}$$

These three steps form the optimisation logic of imbalance sharing. How can this logic be coupled with the local AGC loops? Figure 3.3 shows the traditional AGC structure and its imbalance sharing enhancement. To use the full sharing potential, P_i^{imb} is the difference between ACE and FRR activation, i.e. the open-loop imbalance. The correction signal x_i^{imb} adds to the ACE and affects the power deviation ΔP_i. The open-loop imbalance is the total amount of FRR required, i.e. the sum of activated and yet to be activated AGC resources to restore the ACE of area i to zero. The correction signal is calculated by the imbalance sharing activation logic considering available transfer capacities between areas, the participation status of the TSOs, and the distribution logic. In areas where information about P^{FRR} is not available to the reserve connecting TSO, P^{AGC} or an estimation of P^{FRR} can be used.

The optimisation logic in Figure 3.3 is subject to limitations in the availability of transfer capacities and the overall amount of imbalances in the system. This yields the following constraints:

$$\begin{aligned}
&\underbrace{\sum_{\{j:(i,j)\in T\}} x_{ij}^{\text{tie}}}_{\text{outflow of area } i} - \underbrace{\sum_{\{j:(j,i)\in T\}} x_{ji}^{\text{tie}}}_{\text{inflow of area } i} = \underbrace{x_i^{\text{imb}}}_{\substack{\text{imbalance}\\ \text{reallocation}\\ \text{in area } i}} && \forall i \in A \\
&0 \le x_{ij} \le c_{ij} && \forall (j,i) \in T \\
&0 \le x_i \le |P_i^{\text{imb}}| && \forall i \in A
\end{aligned} \tag{3.10}$$

Standard Form

This formulation neglects active power losses on the tie-lines, as they will be reflected in ΔP_i. For an area $i \in A$ with an imbalance $p_i^{\text{imb}} = 0$, the main constraint can be simplified, as $x_i = 0$ is the only solution, i.e. flow conservation is upheld:

$$\sum_{\{j:(i,j)\in T\}} x_{ij} = \sum_{\{j:(j,i)\in T\}} x_{ji} \tag{3.11}$$

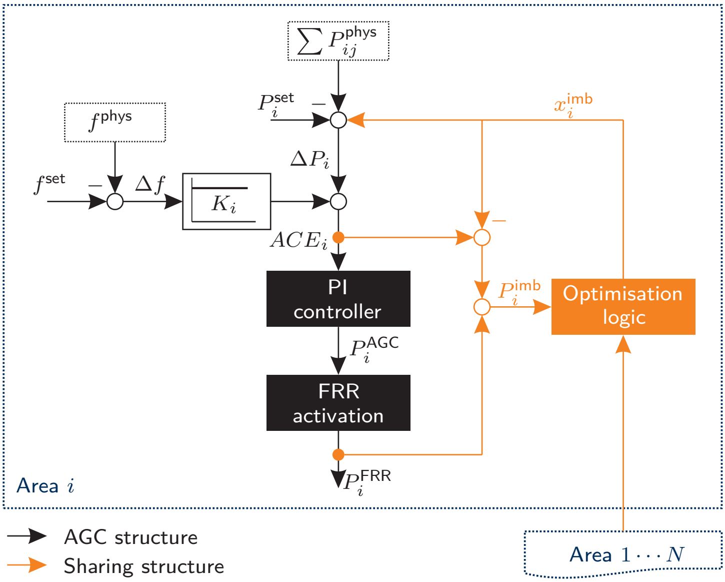


Figure 3.3.: AGC structure according to Figure 3.1 and the sharing enhancement.

In order to efficiently solve the optimisation with a standard solver, and to work towards the operational real-time application requirement discussed in Section 3.2.1, the optimisation problem is to be formulated in a vector-based standard form. All variables must be non-negative, and only inequalities of the correct direction are allowed. Therefore, let $\boldsymbol{x} \in \mathbb{R}^{m+n}$ be the combined decision vector such that

$$\boldsymbol{x} = \begin{bmatrix} (x_{ij}^{\text{tie}}) \\ (x_i^{\text{imb}}) \end{bmatrix} \tag{3.12}$$

The maximisation of imbalance sharing as well as the minimisation of tie-line capacities is a linear problem that can be stated as a linear programming, i.e. $f(\boldsymbol{x}) = \boldsymbol{f}\boldsymbol{x}$. Thus, let $\boldsymbol{\omega}^{\text{imb}} = (\omega_k^{\text{imb}})$ and $\boldsymbol{\omega}^{\text{tie}} = (\omega_k^{\text{tie}})$ both be binary vectors of dimension $m+n$ with $1 \leq k \leq m+n$ such that

$$\omega_k^{\text{imb}} = \begin{cases} 1 & \forall k > m \mid (b_{ii}^{\text{imb}})_{i=k-m} > 0 \\ 0 & \text{otherwise,} \end{cases} \tag{3.13}$$

and

$$\omega_k^{\text{tie}} = \begin{cases} 1 & \forall k < m \\ 0 & \text{otherwise.} \end{cases} \tag{3.14}$$

Distribution Rules

There are different possibilities for choosing the distribution rule. It is assumed that surpluses and shortages are treated equally for several reasons. The applicability of the current quality indicators and threshold values have heretofore been imposed symmetrically. A robust energy balancing framework and its respective imbalance settlement generally favour neither positive nor negative imbalances; thus, the exchange of imbalances does not privilege a positive over a negative imbalance or vice versa. However, asymmetry could easily be imposed in the presence of prices for net imbalances in a control area, but this might also create incentives for imbalance arbitrage. Hence it seems desirable to treat positive and negative imbalances equally. Three possible distribution rules are:

Uniform pro rata: The imbalances are equally shared between the areas. As long as $x_i^{\text{imb}} < |p_i^{\text{imb}}|$, all areas provide the same absolute amount of power to the reallocation. The advantage is that every area is on a par with every other and the reallocation is always independent of the size of an area. However, as larger areas generally have a larger standard deviation of the net imbalance, smaller areas will be more often fully balanced in the imbalance reallocation; and thus, smaller areas will have a better relative balancing performance.

Proportional to imbalance: If an area has a large imbalance, it will receive a higher share though the imbalance reallocation. In this way, the size of an area impacts the reallocation, and the relative balancing performance is proportionally increased. However, irrespective of size, this distribution can create incentives to be intentionally less balanced in order to be more strongly supported by the imbalance reallocation. It should be applied if active power reserve dimensioning and balancing performance criteria are harmonised among the areas.

In inverse ratio to imbalance: If an area has a small initial imbalance, it will receive an inversely proportional share by the imbalance reallocation. Such a distribution rewards the well-performing, i.e. well-balanced areas and incentivises areas to compete for a small absolute real-time imbalance. However, small areas are less incentivised to achieve a high relative balancing performance, which means this creates an incentive to be a small area, and should be applied if areas are of comparable size. Otherwise, small areas have an incentive for higher relative imbalances, i.e. less active power reserves, than large areas, as they receive a higher reallocation share. This distribution can motivate measures against market-induced imbalances. In times of deterministic imbalances, the sharing potential is very small. Hence only the areas with a small imbalance will benefit from imbalance sharing.

A function could also consider a historical component or reflect the generation and load mix, which means areas with more intermittent generation receive higher shares in the imbalance reallocation. It will also always create incentives for arbitrage activity between global imbalance reallocation and local procurement and activation of active power reserves. Table 3.1 shows the corresponding distribution rules and summarises the advantages and drawbacks of the distribution rules. In particular, resistance to gaming greatly depends on the regional market design (see Appendix A).

	Uniform pro rata	Proportional to imbalance	In inverse ratio to imbalance
Distribution function $\omega^{\text{dis}}(x)$	$(x_{ij}^{\text{imb}^2})$	$(x_{ij}^{\text{imb}^2}(p_i^{\text{imb}})^{-1})$	$(x_{ij}^{\text{imb}^2}p_i^{\text{imb}})$
Resistant to gaming	neutral	no	no
Insensitive to area size	yes	no	no
Compete for performance	no	no	yes
Penalise market-induced imbalances	neutral	no	yes

Table 3.1.: Non-exhaustive qualitative evaluation of three distribution rules for imbalance sharing between control areas.

The distribution functions are quadratic and the minimisation of distribution costs can be formulated in standard form for quadratic programming, i.e. $f(\boldsymbol{x}) = \boldsymbol{x}^\top \boldsymbol{F}\boldsymbol{x}$. Thus, let $\boldsymbol{\Omega}^{\text{dis}} = (\omega_{kk}^{\text{dis}})$ be an $(m+n) \times (m+n)$ matrix which consists of a $\boldsymbol{0}_{m,m}$ and a diagonal $n \times n$ matrix. For a uniform imbalance reallocation according to Table 3.1 this simply yields:

$$\boldsymbol{\Omega}^{\text{dis}} = \begin{bmatrix} \boldsymbol{0}_{m,m} & \\ & \boldsymbol{I}_n \end{bmatrix}, \tag{3.15}$$

where $\boldsymbol{I}_n$ is the unit matrix of size n. In standard form the multi-objective optimisation can be written as:

$$\begin{aligned}
&\text{maximise} \quad \boldsymbol{\omega}^{\text{imb}^\top}\boldsymbol{x},\\
&\text{minimise} \quad \boldsymbol{\omega}^{\text{tie}^\top}\boldsymbol{x},\\
&\text{minimise} \quad \boldsymbol{x}^\top\boldsymbol{\Omega}^{\text{dis}}\boldsymbol{x},\\
&\text{subject to:}\\
&\qquad \begin{bmatrix}\boldsymbol{B}^{\text{tie}} & \boldsymbol{B}^{\text{imb}}\end{bmatrix}\boldsymbol{x} = \boldsymbol{0}_{n,1},\\
&\qquad \boldsymbol{0}_{m+n,1} \le \boldsymbol{x} \le \begin{bmatrix}\boldsymbol{C}\\ |\boldsymbol{P}|\end{bmatrix}.
\end{aligned} \tag{3.16}$$

Note that, if distinction costs are available for the tie-line capacities, i.e. $\omega^{\mathsf{dis}}(x_i^{\mathsf{imb}}, x_{ij}^{\mathsf{tie}})$, the first minimisation can be omitted or $\omega_k^{\mathsf{tie}} = \mathbf{0}_{m+n}$.

Multi-Objective Management

There are several ways to proceed from this point due to a plethora of methods and algorithms to solve multi-objective optimisation problems [40]. The choice depends on the complexity of the problem and the availability of problem-specific information on the objectives such as natural or physical principles. In this thesis, the weighted-sum method and pre-emptive optimisation are used, as they match the problem statement well. Both are common a priori approaches, i.e. methods where a priori articulation of preference information is used; however, note that the weighted-sum method can also be used as an a posteriori method where a posteriori articulation of preference information is used [98].

The weighted-sum method (or simply "weighting method") is a scalarisation method[3] that combines multiple objectives into one single-objective scalar function which minimises a positively weighted convex sum of the objectives. In this approach, each objective function is associated with a weighting coefficient. Thus, let $\boldsymbol{\Pi}$ be a weight vector such that the following is a weighted-sum scalarisation of the initial multi-objective optimisation:

$$\text{minimise} \quad -\Pi_1 \boldsymbol{\omega}^{\mathsf{imb}^\top} \boldsymbol{x} + \Pi_2 \boldsymbol{\omega}^{\mathsf{tie}^\top} \boldsymbol{x} + \Pi_3 \boldsymbol{x}^\top \boldsymbol{\Omega}^{\mathsf{dis}} \boldsymbol{x} \tag{3.17}$$

In standard form of a quadratic optimisation, this yields:

$$\text{minimise} \quad \frac{1}{2} \boldsymbol{x}^\top \underbrace{\Pi_3 \boldsymbol{\Omega}^{\mathsf{dis}}}_{\boldsymbol{F}} \boldsymbol{x} + \underbrace{\left[\Pi_2 \boldsymbol{\omega}^{\mathsf{tie}} - \Pi_1 \boldsymbol{f}^{\mathsf{imb}}\right]^\top}_{\boldsymbol{f}} \boldsymbol{x} \tag{3.18}$$

In particular, if the weight vector Π is strictly greater than zero, the single-objective minimiser is a strict Pareto optimum. Furthermore, the unique solution of such a problem is Pareto optimal. Here, the solution of the weighting method is always Pareto optimal if the weighting coefficients are all positive or if the solution is unique, without any further assumptions. From a mathematical perspective, it is noteworthy that not all of the Pareto optimal solutions can be found, unless the problem is convex; at any rate, the imbalance reallocation problem is convex.

[3] Sometimes the weighted-sum method itself is referred to as scalarisation method; however, every method that converts the problem into a single-objective optimisation is a scalarisation method. After scalarising, theory and methods for single-objective optimisation can be used [98].

An alternative a priori approach for a multi-objective problem is pre-emptive optimisation (also referred to as "lexicographic approach"). The idea is to prioritise the objectives according to predefined problem-specific criteria. By doing this, it aims to find one optimal point in the entire Pareto surface. Pre-emptive optimisation orders the objectives according to their priority, which is possible because the objectives have a rather strict hierarchy: First, the maximisers of the imbalance objective function are found; second, the minimisers of the tie-line capacity objective are searched for, and third, the minimisers of the distribution objective are determined. After doing this, all the objective functions have been optimised on successively smaller sets. For this application pre-emptive optimisation is a reasonable approach, as the continuous trade-off among the objective functions is not of overriding interest. However, one drawback is that the distribution problem that is solved last can be largely constrained, and it could even become infeasible in case of a largely complex distribution function, and different orderings of the objectives obviously yield different solutions.

Due to strong prioritisation and the aim to create a unique solution, the weighted-sum method and pre-emptive optimisation can both yield the same result for the imbalance reallocation programming, which allows verifying and comparing the methods and results. In general, it can be said that Π_1 should be chosen such that $\Pi_1 \gg \Pi_3$; otherwise, the distribution costs will largely limit the imbalance reallocation. By contrast, $\Pi_2 > 0$ is sufficient to prevent additional flows that do not contribute to the imbalance reallocation. With $\Pi_2 = 0$, the occurrence of additional flows mainly depends on the optimisation solver, for example, any interior-point methods will almost certainly add additional flows, as they reach their solution by traversing the interior of the feasible region, i.e. not going along the edges of the feasible set which would be the case, for example, with a simplex method (see Section D.1).

Improving the Data Structure

For a large interconnected synchronous area such as Continental Europe, the tie-line incidence matrix for imbalance reallocation $\boldsymbol{B}^{\text{tie}}$ is a sparse matrix, as most elements b_{ij}^{tie} are zero. When setting up the optimisation program, it may result in faster calculations if the matrix is transformed into a band matrix form with a small bandwidth. This is known as the bandwidth minimisation problem: For a given matrix, this is an NP-complete problem, which is to reduce the bandwidth by permuting rows and columns by moving all the nonzero elements in a band as close as possible to the diagonal. This can be done as a pre-processing step before implementing imbalance reallocation, and is typically solved by the Cuthill-McKee algorithm [31].

3.3.2. A Posteriori Reallocation: Reserve Sharing

In the last section, the option of using additional cross-border flows to adjust the local imbalances in order to reduce the global absolute imbalance have been introduced. Additionally, the reserve demand that exceeds the local reserve resources can be rerouted to areas which have free reserves available. This can be done by upgrading the imbalance sharing optimisation logic.

Upgrading the Optimisation Logic

The a posteriori imbalance reallocation can be read as an extended a priori imbalance reallocation problem, where the availability of reserves should also be considered. For each $i \in A$, let $\boldsymbol{R}^{\text{res}} = (r_i^{\text{res}})$ be a vector of dimension n whose elements correspond to the areas' reserve capacity. To describe the relationship between local reserve resources and the areas in the zonal model, let $\boldsymbol{B}^{\text{res}} = (b_{ij}^{\text{res}})$ be a binary $n \times n$ matrix ("reserve incidence matrix") whose n rows correspond to the n areas and whose n columns correspond to n local reserve resources with $1 \leq i \leq n$ such that $b_{ii}^{\text{res}} = 1$ if local reserves are available. To distinguish the power reallocation of imbalance sharing and reserve sharing, let $\tilde{P}_i^{\text{imb}}$ and $\tilde{P}_{ij}^{\text{tie}}$ be the imbalance of area i and the tie-line capacity between area i and j after imbalance sharing, respectively.

Similar to the imbalance reallocation, reserve sharing can be formulated as a non-linear programme with several objectives. The steps depend on the overall objective:

Minimising the activation costs: If reserve sharing is intended to have access to the cheapest reserves, it is proposed to formulate the optimisation in a way that is similar to the imbalance sharing programming. Maximise the availability of reserves to other areas, minimise the use of the tie-line capacity, and minimise the distribution costs which are a function of $\boldsymbol{R}^{\text{res}}$. By doing this, the same distribution rules as discussed for imbalance sharing can be used for reserve sharing, as there is no preference given to local reserves (see Table 3.1).

Maximising the locally available reserves: If reserve sharing is intended to have reserves available from other areas, in case the local reserves are not enough to cover the local imbalance, the optimisation comprises a linear and a quadratic objective: Maximise the availability of reserves to other areas, and minimise the distribution costs associated with it, which are a function of the-line capacity.

The first approach implies a common price formation. As this thesis focuses on the amount of control resources required rather than on their cost effective activation, pricing methodologies are not analysed any further, and preference is given to the second approach, although the first approach, which is subject to the availability of price data, could be considered accordingly. Irrespective of the approach chosen, potential cost savings for a reduction of the procured active power reserves stay the same, only the control energy cost can be further affected by the approach of reserve sharing; however, this is vastly dependent on local energy pricing.

First, the reserves are to be made available to other areas. Let x_i^{res} be a vector of dimension n that contains the decision variables representing the amount of reserves to be made available to another area, i.e. $\omega^{\mathsf{res}}(\tilde{x}_i^{\mathsf{imb}}, x_i^{\mathsf{res}})$. Each decision variable x_i^{res} is bounded with lower bound 0, and upper bound r_i, Therefore, let $\boldsymbol{x}$ be an element of $\mathbb{R}^{m+2n}$ and the combined decision vectors such that

$$\tilde{\boldsymbol{x}} = \begin{bmatrix} (\tilde{x}_{ij}^{\mathsf{tie}}) \\ (\tilde{x}_i^{\mathsf{imb}}) \\ (x_i^{\mathsf{res}}) \end{bmatrix} \tag{3.19}$$

The maximisation of reserve sharing is a linear problem that can be stated as linear programming. Thus, let $\boldsymbol{f}^{\mathsf{res}} = (\omega_k^{\mathsf{res}})$ be a binary vectors of dimension $m + 2n$ with $1 \leq k \leq m + 2n$ such that

$$\omega_k^{\mathsf{imb}} = \begin{cases} 1 & \forall k > m + n \mid (b_{ii}^{\mathsf{res}})_{i=k-m-n} > 0 \\ 0 & \text{otherwise,} \end{cases} \tag{3.20}$$

Second, the distribution costs, i.e. the penalty for accessing reserves from other areas, need to be minimised. The goal is to use local reserves first, and request reserves from other areas only when the local imbalance exceeds local reserve resources. In case of exhausted reserves, the respective TSO is assumed to access the nearest reserves available, i.e. $f^{\mathsf{sha}}(\tilde{x}_{ij}^{\mathsf{tie}})$. With quadratic tie-line capacity costs, the minimisation of the distribution costs will result in the desired behaviour for reserve sharing. Thus, let $\boldsymbol{\Omega}^{\mathsf{sha}} =$

(f_{kk}^{sha}) be a sparse matrix such that

$$\boldsymbol{\Omega}^{\text{sha}} = \begin{bmatrix} \boldsymbol{I}_m & \\ & \boldsymbol{0}_{2n,2n} \end{bmatrix}. \tag{3.21}$$

In standard form, the reserve sharing optimisation can be written such that

$$\begin{aligned} &\text{maximise} \quad \boldsymbol{\omega}^{\text{res}^\top} \boldsymbol{x}, \\ &\text{minimise} \quad \boldsymbol{x}^\top \boldsymbol{\Omega}^{\text{sha}} \boldsymbol{x}, \\ &\text{subject to:} \\ &\qquad \begin{bmatrix} \boldsymbol{B}^{\text{tie}} & \boldsymbol{B}^{\text{imb}} & \boldsymbol{B}^{\text{res}} \end{bmatrix} \boldsymbol{x} = \boldsymbol{0}_{m+2n,1}, \\ &\qquad \boldsymbol{0}_{m+2n,1} \leq \tilde{\boldsymbol{x}} \leq \begin{bmatrix} \tilde{\boldsymbol{C}} \\ |\tilde{\boldsymbol{P}}| \\ \boldsymbol{R}^{\text{res}} \end{bmatrix}. \end{aligned} \tag{3.22}$$

From this point on, the same steps as for imbalance sharing can be applied, i.e. reshape according to Formula 3.18. Note that unlike FCR, local reserves are generally not dimensioned symmetrically. In this case, $\boldsymbol{R}$ can be split such that $\boldsymbol{R}^{\text{res}+}$ and $\boldsymbol{R}^{\text{res}-}$ are both vectors of dimension n whose elements correspond to the n areas' reserve capacities such that $r_i^{\text{res}+}$ denotes the positive and $r_i^{\text{res}-}$ the negative reserves for each area $i \in A$.

3.3.3. Consistency with Established Control Structures

Section 3.3.1 and 3.3.2 outlined a centralisation logic based on the existing AGC structure. There are three basic structures for organising AGC in an area that have already been used in Europe [106,137]. The OpHB refers to these as:

Centralised: AGC for one control area is performed centrally by a single controller; thus, there is no explicit coupling between the AGC loops.

Pluralistic: AGC is performed in a decentralised way with more than one control area; a single TSO (the block co-ordinator) regulates the whole block towards its neighbouring control areas with its own AGC and respective active power reserves, while all the other TSOs of the area regulate their own control areas in a decentralised way on their own.

Hierarchical: AGC is performed in a decentralised way with more than one control area; a single TSO (the block co-ordinator) operates the superposed block controller which directly influences the superior AGC of all control areas of the area; the block co-ordinator may or may not have active power reserves of their own.

Hierarchical Control

Figure 3.1 implicitly implies a centralised or hierarchical structure. In case of a hierarchical structure, only the superior AGC loop of area i would be displayed. Nowadays, hierarchical control is only used to consolidate the small control areas of the Control block of Slovenia, Croatia, and Bosnia-Herzegovina (SHB) and the Control block of Serbia, Montenegro, and the Republic of Macedonia (SMM)[4]. A structure similar to pluralistic control does not seem legitimate for pan-European centralisation. One area would be responsible to have enough reserves to cover all remaining mismatches of all other countries. This is neither economically reasonable nor easy to implement from an operational point of view, as all residual imbalances would need to be reallocated to one single area. As a consequence, a hierarchical structure could be implemented, but congestions cannot be handled with classic AGC principles. However, the proposed control enhancements in light of pan-European centralisation can be read as a setup of hierarchical control, as one central entity is needed to operate the optimisation, and a correction signal, i.e. control signal, is added to the local controllers.

3.4. Subsidiary Measures for Harmonisation

In the following, technical aspects that are either necessary or supportive for a frequency control centralisation are discussed.

[4] Furthermore, Germany operates a superior controller in a pluralistic structure to be able to control the German ACE back to zero in case the German domestic grid control co-operation of the four control areas does not work (see Section 3.3.1); however, the behaviour is the same as that of one single area and Germany is modelled as one control area.

3.4.1. Improved Frequency Bias Factor Sizing

Section 3.2.2 outlined the aim of a synchronous area's bias factor K_i to fully compensate for the initial frequency-response. This can only be achieved if $K_i = \beta_i$ in area i. Furthermore, a precise determination of the local imbalance is desirable in case of AGC coupling in order to deliver the correct open-loop imbalance to the optimisation logic. Currently, the framework for frequency control in the RGCE is given by the 2009 UCTE OpHB [104,106]. Estimation of the total frequency-response characteristic β is currently done "on a regular basis" as specified in the OpHB [105,106]. Apart from these updates, usually occurring less than once a year, "it is taken to remain as constant as possible".

Change in Policy

The 2004 UCTE OpHB defined the K-factor for every control block, or area, as follows: the "contribution coefficient" g_i, calculated as the ratio between electrical energy produced in area i and the total production in the interconnection in one year[5], is used to split the total frequency-response characteristic of the system among the control areas. An additional 10 % was introduced to account for any general uncertainty, assuming that over-estimation of the frequency-response characteristic is preferable. The overall network frequency characteristic β of 18 000 MW/Hz was composed of the FCR speed droops, which were calculated according to the rule that the total FCR of 13 000 MW had to be provided within 200 mHz, and assuming a load self-regulation effect of 10 %/Hz. Since, by OpHB definitions, none of these factors change on an interval shorter than one year, the frequency bias factor of every area is supposed to stay constant for that same interval.

In 2009, the revised OpHB policy on load-frequency control was approved, stating that the frequency bias factor "shall reflect the best approximation of the real network power frequency characteristic". It further postulates that the K-factor calculated by multiplying g_i, and β shall only serve as the default value.

The computation of β changed significantly compared to the 2004 definition, resulting in an overall network frequency-response of 26 680 MW/Hz for 2009. In addition to the FCR from Formula 3.23 and the self-regulation effect from Formula 3.24, which made up β in the previous definition, two new components are added in the 2009 version. The first, Formula 3.25, accounts for the fact that FCR delivers on average 30 % more than planned.

[5] The factor g_i is also used to determine an area's share of the 3000 MW FCR every year.

The second, Formula 3.26, is referred to as "surplus-control of generation"; it originates from a linear frequency dependency of roughly 50 % of the generators in the network. The result of the sum of these four factors is the overall network frequency-response as shown in Formula 3.27.

$$\frac{1}{S^{\mathsf{FCR}}} = \frac{3000\,\mathsf{MW}}{200\,\mathsf{mHz}} \tag{3.23}$$

$$D = 1\frac{\%}{\mathsf{Hz}} \cdot P^{\mathsf{peak}} \tag{3.24}$$

$$\frac{1}{S^{\mathsf{add}}} = 30\,\% \cdot \frac{1}{S^{\mathsf{FCR}}} \tag{3.25}$$

$$\frac{1}{S^{\mathsf{surplus}}} = \frac{50\,\%}{50\,\mathsf{Hz}} \cdot \bar{P}^{\mathsf{gen}} \tag{3.26}$$

$$\beta = \frac{1}{S^{\mathsf{FCR}}} + D + \frac{1}{S^{\mathsf{add}}} + \frac{1}{S^{\mathsf{surplus}}} \tag{3.27}$$

In both editions of the OpHB, the principles of K_i dimensioning are based on the assumption that it is possible to calculate the frequency-response β of the entire system for a specific time range. This assumption incorporates the following four major parts:

- The frequency-response characteristics of the entire interconnection is dependent on only two to four known factors, and is constant for the period of one year
- The frequency response of an interconnected area can be allocated to the constituent areas by multiplication with an allocation factor g_i, where $\sum g_i = 1$.
- The allocation factor is equal to the area's share of annual energy production.
- The frequency-response and its constituents are linear.

Several problems are, however, associated with these assumptions: Early measurements of the UCPTE on interconnected measurements [147,148] showed that there was variability in β depending on the time of day and on the make-up of the generating units. In [149] it is shown, through statistical analysis of post-disturbance data, that there is seasonality to β.

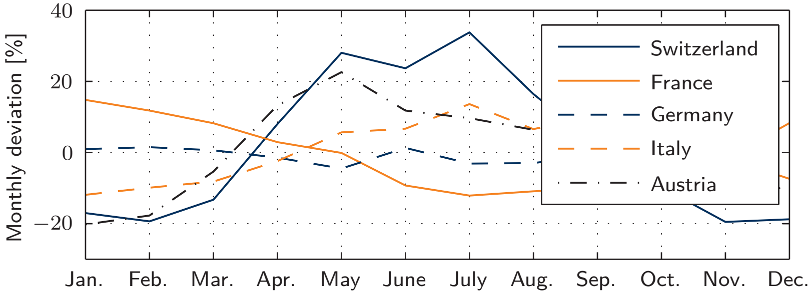


Figure 3.4.: Percentual deviation between monthly and annual calculations; contribution factor calculated for 2009.

The findings can be summarised as β exhibiting system load dependency, which is supported by [159].

Comparing the contribution factors for the RGCE control areas, it can further be shown that there are significant deviations between the calculated contribution factors depending on whether they are determined on an annual or on a monthly basis. Figure 3.4 clearly shows these differences for Switzerland and its neighbouring countries in 2009 [42]. It can be seen that while for Germany the deviation is relatively small, the deviation for Switzerland exceeds 20 % during a quarter of the year and 10 % during 11 of 12 months. This is mainly due to the low amount of electricity-intensive industries in Switzerland. Austria, France, and Italy show similar deviations, albeit not so large.

The size of self-regulation has been studied extensively in [161] and [69]. The results show seasonality similar to the load. Values in winter were roughly one third lower than during summer. Large differences are also exhibited between business hours, weekends, and evening and night hours.

Deterministic Semi-online Sizing

A number of shortcomings of the currently implemented FRR have been identified. A complete redesign of frequency control, could potentially address most of the drawbacks of the established system but entirely retrofitting a vast and complex system requires excessive investments and long-term planning. Therefore, solutions that can be implemented in the short-term have to build on the existing control infrastructure and make use of the research performed in the past. The presented approaches focus on deterministically estimating the current frequency-response characteristic

β_i of an area i in order to set the frequency bias factor K_i of the AGC as close to β_i as possible. In order to achieve this, the four following methods are proposed.

Regular Update

The simplest method of resizing K_i is the recalculation of an area's contribution factor g_i on an interval smaller than one year. The analysis performed above found differences of up to 30 % between annually and monthly calculated contribution factors. It is reasonable to assume that similar discrepancies can be found on shorter time frames as well. Especially for an area such as Switzerland, which has large pumped-storage power plants that act as generation during times of high load and as loads during times of low electricity prices, g_i can change considerably over short intervals.

In order to avoid interfering with the function of the AGC's integration component, an update interval considerably larger than the integration time-constant $T_{N,i}$ has to be selected. In addition to this restriction, market-induced imbalances regularly appearing around the clock mark further difficulties in the timing of updates.

It is thus proposed that update intervals coincide with peak and off-peak times. This results in three contribution factors for each day. One factor for the twelve hours of high generation and load between 8 a.m. and 8 p.m. and two factors for the times of low generation and increased pump-load between 12 p.m. and 8 a.m. and between 8 p.m. and 12 p.m. To avoid interferences with AGC operations around the full hour, the actual update of the K-factor should occur 30 minutes before the beginning of each period. The scheduled power generation levels $P^k_{G,j}$, for all areas j in the synchronous area over the hours k of the following day, are necessary for the calculation of the updated contribution factors $g_i^{l,m}$, where l and m stand for the first and last full hour covered by the factor; $g_i^{l,m}$ is calculated according to Formula 3.28 by dividing the generation of area i by the total generation of all areas over the hours l to m. The frequency bias factor $K_i^{l,m}$ results from the multiplication of $g_i^{l,m}$ with the frequency-response characteristic β determined by ENTSO-E, as shown in Formula 3.29.

$$g_i^{l,m} = \frac{\sum_{k=l}^{m} P^k_{G,i}}{\sum_{k=l}^{m} \sum_{j=1}^{N} P^k_{G,j}} \tag{3.28}$$

$$k_i^{l,m} = g_i^{l,m} \cdot \beta \tag{3.29}$$

The data necessary to perform the calculations to find these three factors are available to the TSOs and the BRPs after the closing of the spot market on the day before operation. These data, however, are subject to forecast errors by the BRPs and does not include intraday trading which occurs after closing of the spot market and during the day of operation until, for example, one hour prior to delivery.

Scaling with Generation

The method presented above uses β given by ENTSO-E. Based on [149, 159] it is evident, however, that β has an approximatively linear dependency on the total generation in the system. Therefore, an improvement on calculating K_i by simply updating g_i as shown in Formula 3.29 is to also scale β with the total load in the system at any point in time. In order to do this, β is divided by the average load of the year that was used as a base for its original calculation P_G^{base} and multiplied by the average load forecasted for the interval in question. Using the nomenclature introduced above, this is demonstrated in Formula 3.30.

$$\beta^{l,m} = \frac{\sum_{k=l}^{m} \sum_{j=1}^{N} P_{G,j}^{k}}{(m-l+1)} \cdot \frac{\beta}{P_G^{\text{base}}} \tag{3.30}$$

Combining Formula 3.29 and Formula 3.30 results in an updated K_i for the hours l to m.

$$K_i^{l,m} = \frac{\sum_{k=l}^{m} P_{G,i}^{k}}{(m-l+1) \cdot P_G^{\text{base}}} \cdot \beta \tag{3.31}$$

This method eliminates the need for the generation forecasts of all areas except for area i itself. This significantly reduces the sensitivity to forecast errors and also eliminates other risks associated with international forecast exchange, i.e. miscommunication, and strategic misinformation.

Construction by Parts

Instead of relying on an annually calculated β, which is commonly based on two-year-old measurements and yearly averages, an algorithm is proposed to determine β_i from its four parts explained above on a much shorter interval and for only one area instead of the entire synchronous area.

The specific values given for FCR, load self-regulation effect and surplus generation in the OpHB formulas stem from research and operating experience of the RGCE. Using these values for the calculation of the frequency-response characteristic of a single area should, therefore, only serve as a default value if more detailed analyses do not exist. The adaptation of

Formula 3.24 to 3.26 to a single area i for the hours l to m of one day, as shown in Formula 3.32 to 3.35, requires the hourly values of the area's forecasted load $P_i^{\text{load},k}$ and generation $P_i^{\text{gen},k}$ as well as the area's FCR $P_i^{\text{FCR},k}$ and results in $K_i^{l,m}$ according to Formula 3.36.

$$\frac{1}{S_i^{\text{FCR},l,m}} = \frac{\sum_{k=l}^{m} P_i^{\text{FCR},k}}{(m-l+1)\cdot 200\,\text{mHz}} \tag{3.32}$$

$$D_i^{l,m} = 1\frac{\%}{\text{Hz}} \cdot \frac{\sum_{k=l}^{m} P_i^{\text{load},k}}{(m-l+1)} \tag{3.33}$$

$$\frac{1}{S_i^{\text{add},l,m}} = 0.3\frac{1}{S_i^{\text{FCR},l,m}} \tag{3.34}$$

$$\frac{1}{S_i^{\text{surplus},l,m}} = 1\frac{\%}{\text{Hz}} \cdot \frac{\sum_{k=l}^{m} P^{\text{gen},k}}{(m-l+1)} \tag{3.35}$$

$$k_i^{l,m} = \frac{1}{(m-l+1)}\Big(1.3\sum_{k=l}^{m}\frac{P_i^{\text{FCR},k}}{200\,\text{mHz}} + 1\frac{\%}{\text{Hz}}\cdot\sum_{k=l}^{m}(P^{\text{load},k}+P^{\text{gen},k})\Big) \tag{3.36}$$

To improve on this adaptation, the specifics of area i have to be taken into consideration for all four contributing effects. In addition, non-linearities of the frequency-response characteristic can be incorporated into a frequency-dependent bias factor $K_i(f)$.

Non-Linear Speed Droop

Calculating FCR according to Formula 3.32 assumes that the activation of FCR occurs linearly in a way that releases the full reserves over the specified band of $\pm 200\,\text{mHz}$. However, all generators have an activation dead band which gives rise to a non-linearity. Additionally, the OpHB specification of speed droop control gives rise to a second non-linearity by requiring that the complete contracted FCR is deployed at $\pm 200\,\text{mHz}$. Therefore, a more realistic, stepwise speed droop integrating these factors is presented schematically in Figure 3.5.

Beyond $\pm 200\,\text{mHz}$ there is little experience in the RGCE. Especially FCR should not be limited to 200 mHz [143]. Additional uncertainty arises from the sometimes unknown behaviour of devices connected to the grid, an actual example being the disconnection of distributed solar generating units.

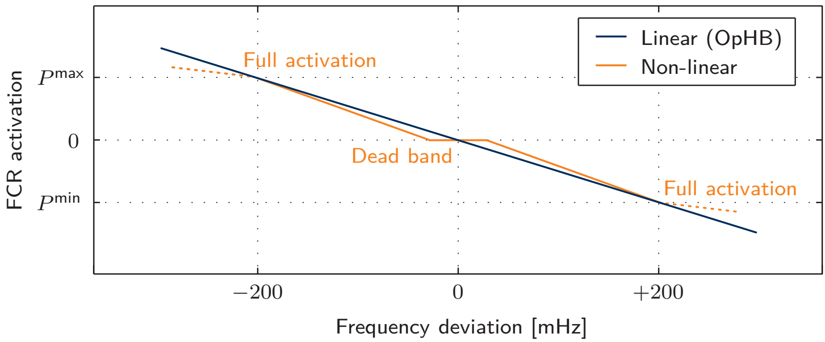


Figure 3.5.: Illustration of a non-linear speed droop model.

The dead band frequencies of most generating units participating in FCR should be known from pre-qualification tests [127] or from other sources such as the manufacturer of the turbine-controller assembly. Furthermore machine-specific non-linearities could be modelled in addition.

Formula 3.34 adds 30 % additional FCR to the auctioned reserves. For an area to improve this empirical value, knowledge of the speed droop controllers present in the system, as well as detailed measurements of their behaviour are needed. A non-linear factor for additional FCR could prove to be beneficial, especially when accounting for generating units which do not officially take part in the auctioned FCR.

The constant surplus generation factor of 1 %/Hz takes into account only the size of the generation in the RGCE grid, which is then split amongst its areas by the contribution factor g_i. It is reasonable to assume that the different types of power plants have different influences on the overall 1 %/Hz surplus generation. A further complication comes with the time-dependence of these shares.

As discussed above, the load self-regulation factor specified by the OpHB is not beyond doubt. For the lack of more current measurements, the following algorithm derived directly from the results of [161] to calculate the load self-regulation factor $D_i^{k,n}$ for the hour k on day n of the week is proposed: The base value $D_{l,i}^{\text{base}}$ is set to 1.8 % for May until September and to 1.2 % during October until April. In order to account for changes during the hours of the day and days of the week, a factor $\gamma_i^{k,n}$, defined in

Formula 3.37, can be used to determine $D_i^{k,n}$ according to Formula 3.38.

$$\gamma_i^{k,n} = \begin{cases} 1.11, & 0 \leq n \leq 5 \wedge 6 \leq k < 18 \\ 0.92, & 6 \leq n \leq 7 \wedge 6 \leq k < 18 \\ 0.92, & 0 \leq k < 6 \\ 0.98, & 18 \leq k < 24 \end{cases} \tag{3.37}$$

$$D_i^{k,n} = \gamma_i^{k,n} \cdot D_i^{\text{base}} \tag{3.38}$$

When constructing β_i the aforementioned four parts contribute different shares and depend on different quantities of the power system, namely load, generation, and FCR present in an area. It is clear that the major influence on recalculating β_i with the algorithms described previously is the modelling of FCR. However, the quality of forecasts concerning load and generation, as well as the load self-regulation factor, also has a considerable significance.

Reduced Power System Model

For the evaluation, the dynamic frequency control model elaborated in Section 3.2.2 is used, and the synchronous area of the RGCE is divided into three different areas (see Appendix B.1). The updating algorithms for the K-factor are implemented in the AGC of the first area. The second area designates the control area which sustains a stepwise discrepancy between its mechanical and its electrical power and the remainder of the RGCE load and generation is concentrated in the third area. The simulation is designed to calculate deviations from normal operation values such as frequency and tie-line power flows. The pre-disturbance properties of the power system are used to determine influences, namely the frequency-response characteristics of the individual areas.

Partitioning the synchronous area in such a way enables the simulation of the AGC reaction in the first area to an outside outage, while incorporating all of the load and generation present in the entire grid at the time of the incident. The ideal outcome for a K-factor calculation would be to have an exact match with β_i. In the simulation, this would equal a complete lack of AGC reaction in the first area to a disturbance in the second area.

The areas contain FCR as well as load self-regulation. These blocks also contain a first order delay modelling the FRR power plants. The system frequency deviation is computed as a result of one single system inertia block, which incorporates all inertial constants of the synchronous area, giving one shared frequency deviation. The mismatch between electrical and mechanical power, which defines the input of the system inertia block, is the difference of the power of the outage in the second area and the sum of the frequency dependent power change in all areas.

The tie-line power flows are calculated as the sum of the frequency dependent power production and consumption in areas one and three. This calculation assumes that during an incident in the second area, no other outages or similar phenomena occur. For the first area, FCR was modelled using different generators with individual, non-linear speed droops including additional FCR. All speed droops feature dead bands of different sizes as well as specific frequencies at which their reserves are fully activated. Therefore, the resulting speed droop differs from the classic assumption of a linear one, especially for small and large frequency deviations. The model parameters of the first area are selected to match the control area Switzerland, which has fast acting FRR. FRR are assumed to be unlimited in all three areas, as the focus is on the influence of the bias factors, i.e. the effect of saturated reserves on control quality is not taken into consideration in the first place. A comparison of the different approaches is given in Section 5.2.3.

3.4.2. Uniform Active Power Reserve Dimensioning

To quantify the economic benefit of a centralisation of frequency control either the total costs of frequency control or the required amount of active power reserves calculated on a common basis can be used as a measure. The latter is chosen in this thesis, as total costs are a monotonic function of the required amount apart from product design and cost structure. Subsequently, to evaluate the potential of an integrated market model, a unified sizing approach for the active power reserves is needed, as the dimensioning methodologies differ across Europe. So far, the UCTE OpHB has provided a framework for the operation of the synchronous area of Continental Europe. However, it does not provide an explicit method for the dimensioning of a control area's active power reserves, but rather standards and recommendations. These recommendations can be used to frame a simple deterministic approach, but cannot cope with a step-by-step centralisation of the pan-European frequency control structure. This is why a probabilistic method will be utilised in this thesis, which allows a transparent and quantitative analysis, whereas the UCTE standards will serve as a comparative reference.

Deterministic Approach

A typical deterministic approach can be framed based on the standards and recommendations given in the UCTE OpHB [104,106]. It is referred to as deterministic since predefined inputs are used and the probability of different system states is not taken into consideration. The UCTE OpHB recommends a minimum amount related to load and generation variations $P^{\text{AGC,min}}$ of automatic reserves for a control area i such that

$$P^{\text{AGC,min}} = \pm\sqrt{a \cdot P_i^{\text{peak}} + b^2} - b, \tag{3.39}$$

where P_i^{peak} is the maximum anticipated peak load of a control area; a and b are empirical parameters given as 10 MW and 150 MW, respectively. The formula is based on French research in 1990 and 1991 under monopolistic structures [93]. The formula points out a larger control area might be preferable as the amount of required reserves is disproportionately smaller to the peak load.

The UCTE OpHB remains vague about the overall amount of automatic and manual active power reserves, and different statements are given. All refer to the classic N-1 criterion, and it can be concluded that if no additional reserve contracts are available the sum of AGC resources and manual replacement reserves should cover the largest unit in the control area. This is not a system-specific requirement, as the probability of such a loss is not considered and as any number of large(st) units might be located in a control area of an arbitrary size. For further discussions of the limitations of deterministic methods and the stochastic nature of reserve dimensioning refer to the discussion of Voorspools and D'haeseleer [156].

Probabilistic Approach

In the following, a probabilistic sizing method for the active power reserves is derived which is similar to the one used by Brückl [17] or Maurer et al. [97]. The method is based on a defined sample, where chronological time-dependencies are not considered, which has the advantage that the method can be derived analytically. The influencing factors causing an imbalance in an area are associated with one or more particular types of active power reserves. Therefore, the deviation and duration need to be anticipated. Subsequently, influencing factors can be described by time-independent distribution functions:

Unit failures: Forced outages units can be modelled time-independently by approximating the unit's behaviour by a two-state Markov process [11,146]. The steady state availability, A^{uo}, of a unit, i, tripping out in the considered time span for the use of control power t_c can be described, as in Formula 3.40, by the expected value of the time span $E[t_c]$, the unit's Mean Time To Failure (MTTF), and Mean Time To Recover (MTTR).

$$A_i^{\text{uo}} = \frac{E[t_c]}{MTTF_i + MTTR_i} \tag{3.40}$$

Under the assumption that the concerned BRP makes use of the maximum allowed time before compensating the loss of power, $E[t_c]$ is t^{FRR} the time to restore frequency for FRR and $t^{\text{FRR+RR}}$ for the total amount of active power reserves, respectively. The maximum compensation time $t^{\text{FRR+RR}}$ is typically between one and two hours [21, 142]. Outages of different units are considered to be independent; the combined distribution function F^{uo} for the portfolio of n power plants is given as

$$F^{\text{uo}} = F_1^{\text{uo}} * F_2^{\text{uo}} * ... * F_n^{\text{uo}}. \tag{3.41}$$

Due to their flexibility[6] and their low number of Full Load Hours (FLH), hydroelectric generation units are often not neglected for active power reserve considerations [32, 65, 116]. Other conventional units are considered with their full nominal power.

Short-term variations: Short-term variations of load and wind are described by a static normal distribution with a standard deviation σ_i^{stv} and a mean μ_i^{stv}. Due to its stochastic nature and as RR have a minimum running time typically equal to or longer than an imbalance period, load variation can only be covered by FRR.

$$F^{\text{stv}} = \mathcal{N}\left(\sum_{i=1}^{n} \mu_i^{\text{stv}}, \sum_{i=1}^{n} {\sigma_i^{\text{stv}}}^2\right) \tag{3.42}$$

Forecast errors: Forecast errors can be described by a normal distribution with a mean μ_i^{fce} and a standard deviation σ_i^{fce}. As forecast errors

[6] Large hydro power plants that consist of several cascaded reservoirs and machine groups are typically operated using load-following to match their scheduled power production. An outage of a single machine is immediately compensated. Only rare cascaded outages such as penstock failures that cause several machine to trip lead to a significant imbalance.

describe the difference between scheduled and current mean value of load or production patterns, both are expected to be covered by RR. Based on the assumption of independence, a distribution function, F^{fce}, describing the sum of all forecast errors can be derived easily.

$$F^{\text{fce}} = \mathcal{N}\left(\sum_{i=1}^{n} \mu_i^{\text{fce}}, \sum_{i=1}^{n} {\sigma_i^{\text{fce}}}^2\right) \tag{3.43}$$

The deviation in power relevant to FRR and RR in a given area is the sum of all imbalances in the area. As the influencing factors described are assumed independent, a combined probability distribution can be derived for the different types of active power reserves. The combined probability distribution, F^{FRR} for AGC resources is given as

$$F^{\text{FRR}} = F^{\text{stv}} * F^{\text{uo}}\Big|_{t_c = t^{\text{FRR}}}. \tag{3.44}$$

Every imbalance that is designated to be compensated by RR may be balanced by FRR as well, but not vice versa. To consider this effect, not the combined probability function for RR (running time: t^{RR}) but that for the sum of FRR and RR is of interest such that

$$F^{\text{FRR+RR}} = F^{\text{fce}} * F^{\text{stv}} * F^{\text{uo}}\Big|_{t_c = t^{\text{FRR+RR}}}. \tag{3.45}$$

For the determination of the required amount of reserves an accepted deficit probability must be defined; for a given time window, for example, one year, this refers to the expected and accepted time the available amount of reserves is not sufficient to cover the imbalance in a given area. In such situations TSOs can rely on neighbouring areas or measures outside market activity such as load (under frequency) or production (over frequency) shedding.

The UCTE OpHB stipulates a deficit probability of $p^{\text{def}} = 0.1\,\%$ without dictating the precise interpretation of this number [106]. This value is read differently, either for each amount of negative and positive reserve (total deficit level of 0.4 %) or for each type of reserve (total deficit of 0.2 % [9, 74, 75, 77, 90, 132]. For computing the respective quantiles, the quantile function $F^{-1}(p)$ for a distribution function $F(x)$ is defined such that

$$F^{-1}(p) = \text{inf}\{x \mid F(x) \geq p\}. \tag{3.46}$$

Based on F^{FRR} and $F^{\text{FRR+RR}}$, the amounts of active power reserves are determined. This approach is subject to several simplifications that emphasise the difference between the time-independent active power reserve sizing and the time-dependent imbalance modelling as introduced in the first part of this chapter, namely:

- If only MTTF and MTTR are known, active power reserves are also dimensioning for times, when the unit has a planned down time, i.e. on average there are reserves available for this unit. This biases the sizing if the unit has a low number of FLH such as peaking units. In systems with a little amount of base load units or a significant amount of large peaking units, for example, Switzerland, this effect should be considered and the dimensioning of reserves should be done accordingly in a dynamic way, i.e. include the planned down times.

- The impact of load profiles and non-compliant schedule changes in combination with market products related to the imbalance period are generally not considered in practical reserve dimensioning that typically has to be approved by national regulatory authorities. And if, only the extent in which it has small impact on the overall amount of reserves [30,77].

- The control quality and the availability of the reserves are generally assumed to have no significant effect on the dimensioning. Minor influencing factors associated with the network topology and operational matters such as congestions, prediction of active losses, and rare operational conditions, for example, island operation, cannot be assumed to be independent and are generally not considered in the Continental European dimensioning, as the system is highly meshed.

- The time-independent approach for active power reserve dimensioning, even when applied to shorter time periods such as in Switzerland, makes it hard to comply with the dimensioning criterion, i.e.

the deficit probability[7]. The most obvious reason for this is the strict decoupling of automatic and manual reserves during dimensioning: it is not possible to flawlessly forecast the forecast errors of BRPs.

The reasoning for these simplifications can be found in the regulatory implications of active power reserve dimensioning, which can even exceed costs of transmission assets and operation [139]. National regulatory authorities focus on a standardised approach rather than on compliance with operational limits that are not obvious to monitor [133].

[7] To the author's knowledge, the Swiss TSO is the only one that validated and published the actual deficit level.

4. Scenario Definition and Imbalance Modelling

This chapter derives data input and scenarios to be used for the reduced synchronous area model and concepts elaborated in Section 3. First, scenarios for the future European development are outlined. Second, the different properties of imbalances causing a mismatch between generation and demand are elaborated. Finally, the handling of imbalance periods is described and the activation pattern for RR is derived. Together, they build the basis for Monte Carlo simulations, which will be conducted in Chapter 5, to compute imbalances relevant to frequency control.
Parts of this chapter have been published in [1,123,128,129].

4.1. Input Data

The objective is to investigate the frequency control structure and performance. Figure 4.1 outlines the detailed simulation framework, which will be elaborated step-by-step in this chapter. As shown in Figure 4.2, the geographical scope comprises the Continental European synchronous area consisting of 22 countries[1]. The simulation is based on a time-sequential model of imbalances from 2015 to 2030. Data from 2009 to 2014 are used for reasons of calibration and validation. Note that the model is run with a minute resolution, and a year always consists of 8760 h, 365 d, or 12 months with no extra or intercalary day in February.

[1] One half of Denmark belongs to the Nordic power system, while the other half is part of Germany. It is a small LFC subarea incorporated in the German LFC block. Denmark operates a AGC loop, but the imbalance is part of the German one. Due to its very small size, Denmark is not modelled separately in this thesis. Moreover, Luxembourg is part of the control area of Germany and Belgium; separate data were not available.

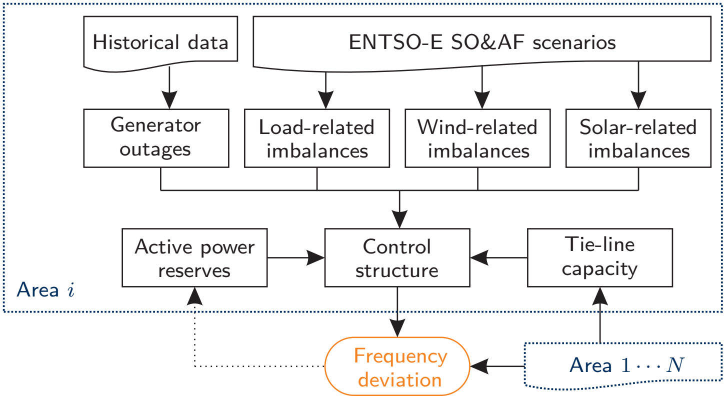


Figure 4.1.: Overview of the simulation framework for the Continental European power system.

4.1.1. Reference Profiles and Generation Portfolio

Scenarios

To define both future frequency behaviour and the range within which reserves will be required, two generation and demand scenarios are created, i.e. Scenario 1 and Scenario 2. They are based on the ENTSO-E SO&AF (see Section 2.3.1) and provide reference points for future load and wind as well as solar power production [46,48]. Scenario 1 assumes some rather reluctant investment behaviour and is based on the conservative bottom-up ENTSO-E Scenario A and Vision 1, whereas Scenario 2 is based on the optimistic top-down Scenario EU2020 and the ENTSO-E Vision 4 ("green vision").

Seasonality and Standard Profiles

The scenario data were reviewed to obtain reference points for each country which can be scaled with standard load profiles and typical load factors. Both have been determined based on historical data between 2009 and 2011. The standard load profiles of each of the 22 countries were obtained from the publicly shared "ENTSO-E Statistical Database" [52]. The load factors, i.e. degree of utilisation, for wind and solar power production have been determined from historical utilisation factors according to the Pan-European Climate Database (PECD). The resulting values serve as input for the imbalance modelling and ensure a realistic evolvement of both intermittent generation and demand, which inherently cover seasonality and daily patterns.

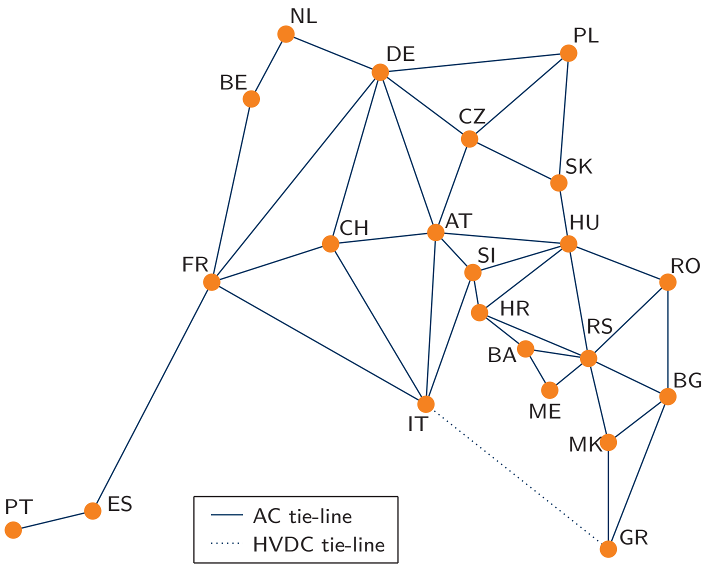


Figure 4.2.: Map of the ENTSO-E system of Continental Europe aggregated into 22 areas according to [107]; HVDC interconnections to adjacent synchronous areas are not considered.

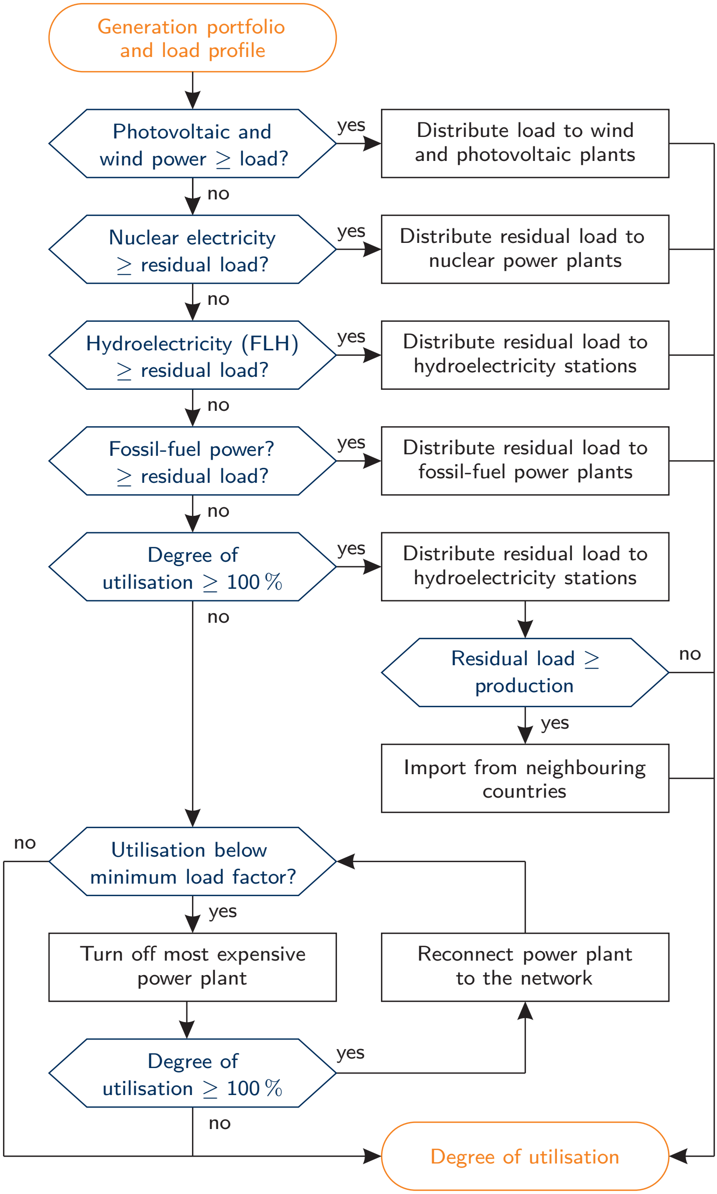


Figure 4.3.: Heuristic process to determine the degree of utilisation of the generation portfolio in an area and the cross-border schedules.

Degree of Utilisation

For the modelling of the reserve-related behaviour of the conventional generation portfolio, the currently installed power plants in the RGCE have been considered. The respective data were made available through ENTSO-E and the former UCTE, and the detailed modelling parameters can be found in Appendix B. The unit commitment in each area, i.e. the degree of utilisation for the generation portfolio, is calculated iteratively based on a generic merit order. This heuristic process is shown in Figure 4.3. Photovoltaic and wind power production is given precedence. Both are considered as must-run and are only limited if the demand is smaller than the total amount of photovoltaic and wind power production. As nuclear power plants are highly inflexible, it is assumed that they operate at nominal power, if the residual load is not below this nominal power. If it is, their actual power is decreased, and the residual load is distributed to the nuclear power plants. Otherwise, the residual load is distributed to the hydroelectricity power plants up to their average FLH share. By doing this, run-of-river power plants and must-run hydroelectric generation is considered, yet without daily or annual variations. Any residual load is further distributed to fossil-fuel power plants, namely gas, lignite, and oil. If the load is not yet covered, for example, during peaking power hours or in case of an outage of large nuclear power plants, the load factors of the hydroelectric power plants are gradually increased up to 100 %, if needed. This implies that pumped-storage hydroelectric stations will turbine their water reserves to cover the load. If there still is a residual load to be covered, albeit all power plants are operating at nominal power, the remaining power is imported from neighbouring countries. In this way, only a basic import and export behaviour is considered. This simplification can be made, as Continental Europe as a whole (the overall sum of production) is considered in this thesis. In reality, it might be cheaper to import from a neighbouring market instead of producing in the domestic area, for example, if the marginal prices differ. However, the unit physically producing the required energy could be of the same technology, and the only difference would be that in case of an outage, not the local TSO but the TSO in the neighbouring country would have to compensate for it.

Each type of power plant has a physical minimal load factor, which should not be undershot. This is also considered, as is shown in Figure 4.3. Generation is redirected step-by-step until the minimum load factors are met. To decide which generator type has to be turned off first, the merit order in reverse order is applied. It has to be mentioned that the different startup times of the generating units are not considered, as the focus is on a realistic outage behaviour, whereas the co-ordination and commitment of generating units to meet ramping requirements fall to the power plant operators and the respective BRP. Subsequently, the unit commitment is assumed to be done with the resolution of the imbalance period.

4.1.2. Access to Transfer Capacity

As mentioned in Section 2.2.2, the remaining transfer capacity after intraday trading is an obvious choice to be used for frequency control actions. However, this capacity is highly changeable and can hardly be predetermined due to market activity and the capacity assessment by the respective TSOs. Instead, three predetermined transfer capacity limits are evaluated:

Unlimited: To determine a reference for the maximum impact of sharing processes, the full NTC between the control areas can be used (see Section 2.2.2 for the capacity definition).

Reliability margin: The TRM is meant to cope with inadvertent deviations due to frequency-response reserves, AGC actions, and MEAS [57]. Sharing processes are not explicitly foreseen to be covered by the TRM, but the TRM sizing is a TSO responsibility and not necessarily related to market activity. Based on ENTSO-E recommendations, the TRM in megawatts between two neighbouring areas i and j is typically calculated such that

$$c_{ij}^{\mathsf{TRM}} = 100\sqrt{n}, \tag{4.1}$$

where n is the number of tie-lines between the areas [3,144]. If the TRM were also to be used for imbalance sharing, one could assume $c_{ij}^{\mathsf{TRM}} = c_{ij}$, and imbalance sharing would be treated in the same way as a frequency-response reserve activation. However, expanding the usage of the TRM to reserve sharing cannot be taken for granted, as reserve products compete with wholesale products, which will be discussed further in Section 5.3.

Unidirectional: Imbalance or reserve sharing is only allowed when it frees up congested borders. As this may differ due to seasonality, the generally congested direction according to [50] is set to zero, whereas the opposite direction is equal to the unlimited case. This approach is considered conservative, as it limits the possibility to use control areas as transshipment areas for sharing processes. It also means that sharing processes do not interfere with the market-related capacity allocation, as this capacity has neither been used by traders, nor is it part of an operational security or planning margin.

.

4.2. Modelling of Imbalances

In Section 2.3.3, the different types of imbalances and how they are distinguished by duration and influence time frame (see Figure 2.8) have been discussed. In the following, they are described mathematically. As literature offers little practical data to model imbalances for frequency control purposes, some empirical data from the Swiss power system are extrapolated for a European-wide usage. Appendix A discusses further to what extent Swiss data are universally applicable to other systems.

For load as well as wind and solar power production, the imbalance period divides into short-term variation and forecast error (also see Figure 2.8), as the legal unbundling implies the separation between energy balancing and frequency control. The extent to which the TSO can anticipate the forecast error of BRPs is decisive for the possibility to activate manual reserves, i.e. RR. For the BRP, the shorter the imbalance period, the higher the resolution of the schedule that can be announced, and subsequently, the smaller the forecast error. This deduction is based on the assumption that market products are aligned to the imbalance period. In cases of low market liquidity and low imbalance prices, a BRP may favour the cheapest standard product which currently is the hourly product on the day-ahead markets. This similarly applies to forced power plant outages; spot trading can only compensate for such a loss at short notice if respective products are available. Due to a low market activity[2] BRPs did not make use of quarter-hourly products on the intraday market in the first years after their introduction [29]. Therefore, the following aspects need to be considered

[2] Instead, the main market players in the first years were the four German TSOs, which used quarter-hourly products to balance wind and solar power infeed, as these TSOs also act as a BRP and participate in energy balancing.

for the modelling of short-term variations, forecast errors, and the compensation of forced power plant outages:

Imbalance pricing incentivation: The imbalance period defines the shortest possible standard products, but the imbalance pricing system needs to set proper incentives for BRPs to rely on these. Basically, the price for the predictable imbalance created by not utilising the shortest available product always has to be higher than the costs of that product. For example, quarter-hourly intraday products often feature a higher price volatility than hourly day-ahead products (see Appendix A for a discussion of the experience in the Swiss system). Therefore, forecast errors can be characterised by standard products of different duration. As a result, the forecast error becomes a function of the imbalance period of the respective standard product.

Load-following: A certain amount of the BRPs comprising load and production apply short-term unit commitment, and therefore, operate using load-following[3]. In particular in regions with an imbalance period of 60 minutes, BRPs trade OTC and feature intra-hour scheduling [80]. The rest of the BRPs will rely on schedule-based operation; for them, the imbalance period is the defining factor.

TSO forecast capability: To anticipate imbalances and proactively activate power reserves, the TSO needs to perform short-term (error) forecasting. Typically, the TSO receives, if any, load and production planning data of the BRPs as schedule notification before real-time, i.e. at the same resolution as the imbalance period; thus, the possibilities to do any short-term forecasting in order to plan the active power reserve activation are very limited if no further data are supplied to the TSO. The general exception is intermittent generation, as TSOs or an associated legal entity usually manage the share of the nationally subsidised intermittent generation by managing a respective BRP. The imbalances of this BRP are equal to the control area's forecast error that the TSO has to compensate.

[3] Load-following also covers production-following, i.e. the concept of adjusting loads in order to compensate for fluctuations in the production portfolio.

4.2.1. Forced Outage Rates

The determination of the degree of utilisation of each unit in Section 4.1.1 allows modelling realistic outage behaviour. Forced outages of generating units can be modelled using a two-state model [11]. The expected number of trips per year is used to calculate the probability for each unit to trip at a certain minute. It is assumed that the probability for a certain unit to trip is constant in time. Therefore, a Poisson distribution is used to determine the probability for each unit to trip at a certain minute such that

$$f(\lambda) = 1 - \exp\left(\frac{-\lambda}{525600}\right), \tag{4.2}$$

where $f(\lambda)$ is the probability for the unit to trip within a certain number of minutes and λ is the number of trips per year for the unit. The number of trips per year must be divided by the number of minutes in a year (525 600 h for a non-leap year), as the probability to be calculated is the probability within each minute. When a unit trips, the BRP experiences an imbalance for a time span t_c (typically $t^{\mathsf{FRR+RR}}$) for which the TSO has to compensate (see Section 3.4.2). After that time, the unit is considered to have a planned outage and is not available in the scope of the unit commitment. After the time to repair, the unit is available again in the process for determining the degree of utilisation according to Figure 4.3.

Reliability Parameters

Literature indicates a wide range of statistics for the purpose of failure modelling. Roggenbau [116] presented an overview of German statistics from the late 1990s which has also been used in follow-up work and recent international studies [17,32,75,132]. Billinton and Li [12] presented detailed statistics which also consider the unit's nominal power. The data were gathered from the Equipment Reliability Information System (ERIS) of the Canadian Electrical Association (CEA) based on recordings between January 1986 and December 1990. Both Billinton and Li [12] as well as Roggenbau [116] do not thoroughly differentiate between planned and forced outages, and their values cannot be used for active power reserve studies without vastly overestimating the impact of power plant outages.

Typically, plant-specific failure statistics are not centrally collected in Europe. Therefore, forced outage rates were collected for Belgium, Croatia, the Czech Republic, France, Germany, the Netherlands, Poland, Spain, and Switzerland in the course of this thesis. Concerning the generating units, the basic technologies were distinguished, and the respective manufacturer as well as the commissioning date were assumed to be identical. Based on these numbers, generally applicable weighted average values were calculated. Subsequently, these numbers do not take into account country-specific variations and any possible dependency on the unit's nominal power. Failures caused by system components such as bus bars and transformers are not considered, as the network topology is not explicitly taken into consideration.

For the detailed reliability parameters and the evaluation of the forced unit outage rates see in Appendix B.2. Conventional power plants have a typical lifespan of decades, and regular retrofits usually have little impact on the nominal power. Therefore, the most important changes until 2030 are caused by the decommissioning of large power plants, namely Belgian, German and Swiss nuclear power plants, which is discussed in Appendix B.4.

4.2.2. Load-Related Imbalances

Load Forecasting

In the scope of load forecasting, a distinction is drawn between Short-Term Load Forecasting (STLF) and Very Short-Time Load Forecasts (VSTLF). Both terms were characterised in pre-liberalisation times. STLF referred to the prediction of the hourly or half-hourly load for up to one week to ensure efficient operation and economic dispatch, whereas VSTLF was used by the utilities to relieve AGC and to ensure generation matched load close to real-time [27,71]. In liberalised market structures, STLF is used by BRPs for load scheduling, and its error defines the load forecast error. VSTLF can be used for BRP's load-following and for a TSO's active power reserve activation planning.

Load forecasting has been well studied. Its error shows similar patterns in largely different systems, namely the United States [94], Northern Europe [38,135], or Germany [17,39]. Due to the highly repetitive nature of the daily load profile, load forecast errors are not particularly sensitive to the forecast horizon and are usually proportional to the size of the load at any given hour. Thus, seasonality and daily profile are imposed by the system load[4].

Both the load forecast error and the spontaneous load variation can be modelled as a normally distributed stochastic variable with a mean

[4]This statement is limited to sufficiently large areas, local demand such as distribution systems can be vastly influenced by local patterns [19].

μ of zero and a standard deviation σ [17, 38, 39, 94, 135]. For practical application and to exclude computational errors, the distribution should be doubly truncated, as values of a normally distributed random variable can, in theory, assume any value (see Appendix D.3). Let the total load error $\boldsymbol{P}_i^{\mathsf{L}}$ for each area $i \in A$ be normally distributed with a density function f_i^{L} such that

$$\boldsymbol{P}_i^{\mathsf{L}} \sim \mathcal{N}(\mu_i^{\mathsf{L}}, (\sigma_i^{\mathsf{L}})^2). \tag{4.3}$$

Load Forecast Error

The total load error can be decomposed into load forecast error $f_i^{\mathsf{L,lfe}}$ and load short-term variations $f_i^{\mathsf{L,stv}}$, which are stochastically independent. For the standard deviation this yields

$$\sigma_i^{\mathsf{L}} = \sqrt{(\sigma_i^{\mathsf{L,lfe}})^2 + (\sigma_i^{\mathsf{L,stv}})^2}. \tag{4.4}$$

As mentioned before, the standard deviation is a function of the actual load $\boldsymbol{P}_i^{\mathsf{L}}$ and the imbalance period T^{ibp} to which the error corresponds. To omit the time dependency, the peak load $P_i^{\mathsf{L,max}}$ is often used instead of the actual system load. This simplification has frequently been used for active power reserve dimensioning [17,38]. For the peak load related standard deviation, Brückl [17] proposes values between 2.0 % (peak load of 27 GW) and 2.8 % (peak load of 10 GW) for an hourly forecasting basis, but without specifying its dependence on the imbalance period. Doherty and O'Malley [38] stipulate an hourly load forecast error of 75 MW for the 7.5 GW system of Ireland. Makarov et al. [96] derived detailed hourly load forecast statistics for all four seasons for the California Power System resulting in a standard deviation of 1.41 % of the yearly peak load.

To obtain the load forecast error as a function of the system load, empirical data from the Swiss power system were analysed between the beginning of 2013 and the first quarter of 2015. The years 2009 to 2012 turned out to be potentially biased by strategic market behaviour, as investigated in Appendix A. In Switzerland, the market is only partially liberalised, and only end-consumers with a yearly consumption of more than 100 MWh have free market access. Most end-consumers receive full service provision from BRPs which replaced the utilities that formerly operated under monopolistic structures. There were three BRPs managing a contiguous geographical area that covers roughly 50 % of Switzerland, so that their load forecasting represents a largely ideal behaviour. Two more BRPs managing a contiguous geographical area of roughly 35 % are operated using load-following. In the following, the results of the analysis of empirical Swiss data are presented; also see Appendix A for a detailed discussion of the representability of Swiss BRPs.

Figure 4.4 illustrates the extrapolation of the standard deviation of the load forecast error. Figure 4.4a shows the relative standard deviation of the three BRPs as a function of the system load for all three years. Neither do the years significantly differ, nor could a significant seasonality or linear correlation be found. To extend the data set, the information can be used that any combination of the BRPs is also a possible realisation for which the load forecast error needs to be described. According to the binomial theorem, the number of all possible combinations for n time series is calculated as

$$\sum_{k=1}^{n} \binom{n}{k} - 1 = 2^n - 1. \tag{4.5}$$

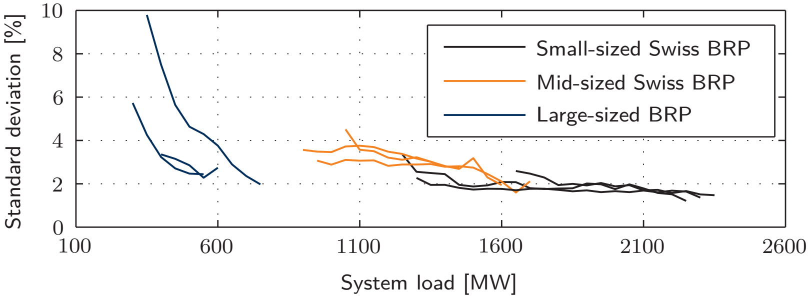
This provides an additional four combinations which are shown in Figure 4.4b. The combined forecast error decreases further and confirms the stipulated assumption that the areas make forecasts independently of each other. Their errors do not correlate significantly. Figure 4.4c demonstrates the extrapolation of both a single and a combined forecast error. The error can be split into a size-dependent share $\sigma^{\mathsf{L,lfe,d}}$ and a size-independent share $\sigma^{\mathsf{L,lfe,i}}$ such that

$$\lim_{P^{\mathsf{L}} \to \infty} \sigma^{\mathsf{L,lfe}} = \sigma^{\mathsf{L,lfe,i}}. \tag{4.6}$$

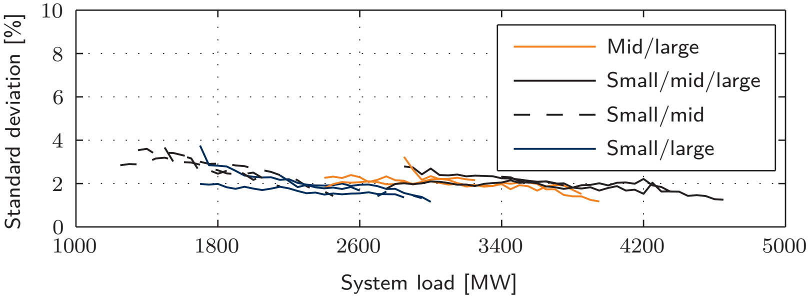
The dependent share decreases disproportionately with the system size. Given that the shares are independent of each other, the extrapolation can be done by fitting the empirical data to

$$\sigma^{\mathsf{L,lfe}} = \sqrt{(\varsigma^{\mathsf{lfe,i}})^2 + \frac{(\varsigma^{\mathsf{lfe,d}})^2}{P^{\mathsf{L}}}}, \tag{4.7}$$

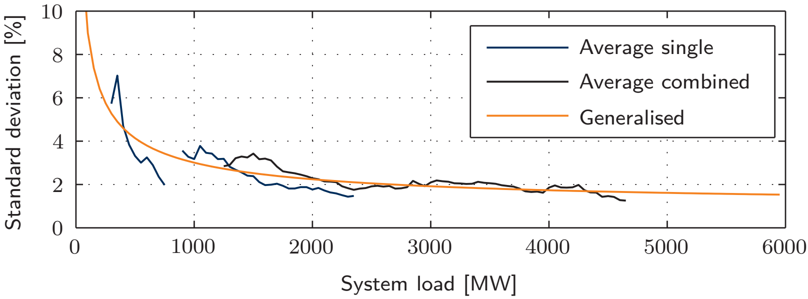
where ς^{i} can be seen as the proportion to which the load forecast error depends on the system size. Generalisation of the Swiss data between 2013



(a) The relative quarter-hourly standard deviation of Swiss BRPs.



(b) The relative quarter-hourly standard deviation of all possible BRP combinations.



(c) Generalisation of the relative quarter-hourly standard deviation.

Figure 4.4.: Derivation of a generalised relative standard deviation of the quarter-hourly load forecast error by fitting empirical data of BRPs which cover a contiguous geographical area in the Swiss power system.

and 2015 as shown in Figure 4.4c results in $\varsigma^{\mathsf{L,lfe,i}} = 0.00995$ and $\varsigma^{\mathsf{lfe,d}} = 0.8973$. This value for the dependent share is supported by Brückl [17] who proposed $1\,\%$ of independent error. Edwin et al. [39] performed evaluations in the 1990s and proposed an independent share between $3\,\%$ and $4\,\%$. To match this with Formula 4.7, this means $\varsigma^{\mathsf{lfe,d}} = 1$ and $P^{\mathsf{L}} = P^{\mathsf{L,max}}$. The reason for this high value might be less advanced forecasting techniques, the fact that this value was meant for an hourly forecast error for pre-liberalisation system operation, or the nature of their conservative system modelling.

Zero Crossing

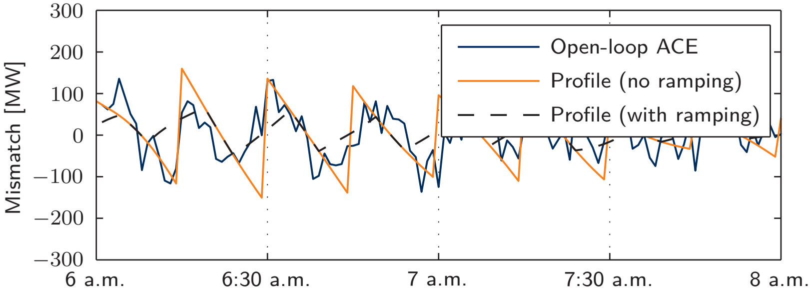
For the load forecast error, the mean time and the median time to zero crossing is around 2 h and 1.5 h, respectively, according to Brückl [17]. Swiss data between 2011 and 2013 indicate that the zero crossing of the load forecast error has a median of 2 h. In general, the net forecast typically changes $96\,\%$ of time within 4 h [20]. This behaviour can be captured by assuming the distribution to zero crossing to be a Poisson distribution (see Appendix D.3). This can be interpreted as a first order, i.e. memoryless, Markov process.

Schedule-Based Operation

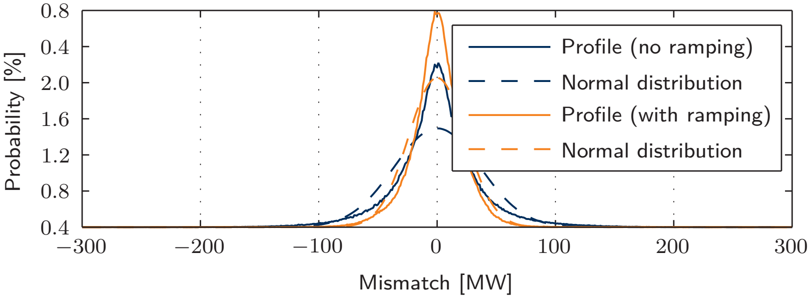
In order to determine the effect of schedule-based operation and respective ramping conditions, the load curve needs to be described. The resolution of the time series on which the forecast error is based, i.e. 15 minutes in Switzerland, is too low. Neither TSO nor DSOs have high frequency load metering for their geographical area, as industrial state-of-the-art meters generally operate at a resolution of 15 minutes[5] [154]. Empirical data need to be interpolated into compatible higher frequency data. This is done in two steps. First, the basic load profile is determined by means of temporal disaggregation (see Section D.2). Second, spontaneous load variations are added to incorporate the short-term high frequency deviations in the load profile.

Independent of the ramping restrictions, BRPs usually forecast their load as mean value per imbalance period. The load profile determines the major share of the short-term variations during times of constantly increasing (morning hours) or decreasing load. At a constant load level, this share is zero. Figure 4.5 summarises investigations of Swiss data. Figure 4.5a shows a random example from December 2011 which compares the open-loop ACE and load profile with and without a schedule ramping period of 10 min-

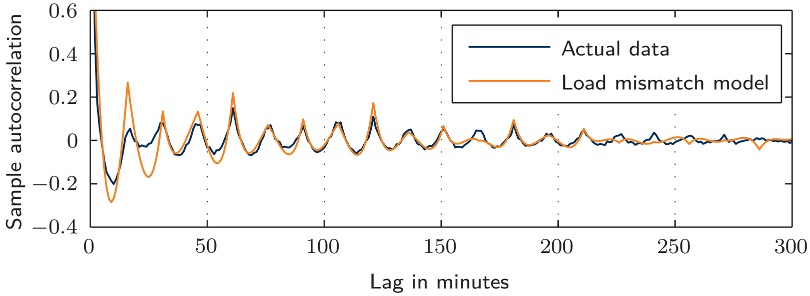
[5] Not to be confused with portable or permanently installed measuring devices, which are typically used for monitoring, for example, substations or demand-side management controlled households.



(a) Example of a comparison between open-loop ACE and load profile in Switzerland (dated December 2011).



(b) Distribution of the load profile model with and without ramping.



(c) Autocorrelation of Swiss load profile.

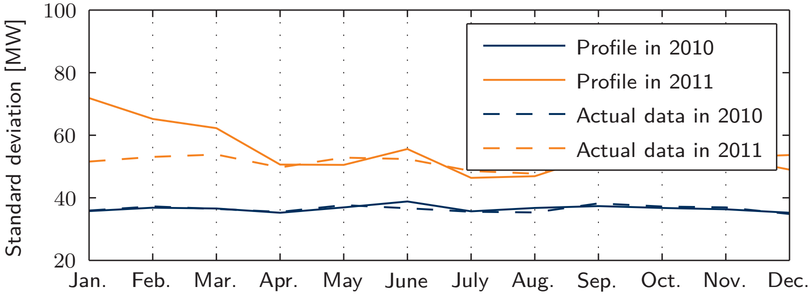
Figure 4.5.: Summary of the load profile model validation based on the example of the Swiss power system for the year 2011.

utes. It can be seen that some Swiss BRPs have properly implemented the ramping, whereas others have not; thus, the actual behaviour is between the two load profile trends. Figure 4.5b shows the yearly distribution of the modelled zigzag-shaped load profile to a normal distribution with ($\mu = 0$ and $\sigma = 24$ MW) and without ($\mu = 0$ and $\sigma = 36$ MW) ramping: A normal distribution cannot sufficiently capture the heavy-tailed behaviour of the load profiles. Figure 4.5c shows the autocorrelation of the mean adjusted open-loop ACE and the load profile model. A comparison of the autocorrelation of the load profile with the mean adjusted open-loop ACE shows good overall matching. Mismatches occur in the small and high lag range. There are several reasons for these differences: It is not known which BRPs actually apply the ramping period and which do not. Only the call for activation of manual reserves is recorded; neither the actual delivery nor the ramping of the delivery is monitored, i.e. manual reserves can be activated at any time independent of the schedule interval. On top of that, the dynamics of the BRPs, which operated using load-following, are not known (see Section 4.2.3). As a consequence, the Swiss open-loop ACE signal also exhibits low frequency components which cannot be taken as a common pattern for European countries [26].

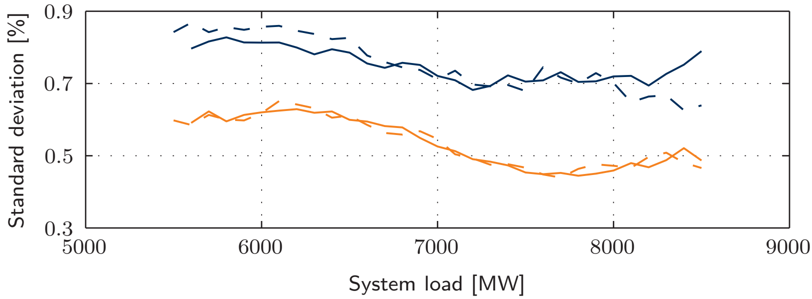
Spontaneous Load Variation

To complete the load behaviour modelling, the spontaneous load variation that adds to the load profile has to be determined. Similar to the load forecast error, the spontaneous load variation is a function of the actual load. Little information can be found in literature. Several studies assume that the total short-term load variation within a quarter of an hour depends on the peak load; and a standard deviation of 0.5 % or scaling a 10 GW reference system are two common proposals [9,77,116]. For Germany, empirical one-minute data indicated a standard deviation of 0.26 % of the peak load at the beginning of 2010 [30]. These measurements were carried out the beginning of 2010, but peak load usually occurs in December, and is around 84 GW for Germany at this time, which is why this approach does not seem to make much sense.

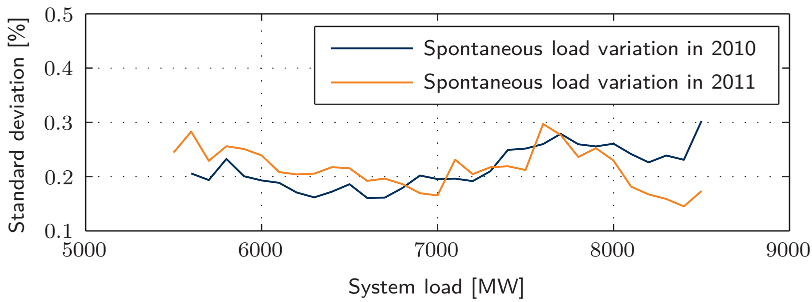
Due to a lack of information, extracting spontaneous load variations from empirical Swiss data has turned out to be quite difficult. This is why calculating the difference between load profile and mean adjusted open-loop ACE is an approach with limited information, but the Swiss data can be used as an indication. It is assumed that the remaining spontaneous load variation adds to the load profile, and the empirical Swiss mismatch can serve as a reference for modelling. For this reason, the load dependence



(a) Monthly comparison between load profile model (without ramping) and historical open-loop ACE; seasonality is well-captured.



(b) Comparison between load profile model (without ramping) and historical open-loop ACE as a function of the total system load; the load-dependence is also well-captured (same legend as in Figure 4.6a).



(c) The relative spontaneous load variation as a function of the system load.

Figure 4.6.: Derivation of the spontaneous load variation model.

of the spontaneous load variation has been investigated. The investigation showed that the relative spontaneous load variation is size-independent and can be well modelled with 0.3 % of the actual load. Figure 4.6 illustrates the derivation of the spontaneous load variation. Figure 4.6b shows the seasonal conformity between short-term load variation and load profile model, whereas Figure 4.6c depicts the size-independence of the relative standard deviation of the spontaneous load variation.

4.2.3. Load-Following Operation

Two large Swiss BRPs that operate using load-following[6] exhibit a yearly mean load of 500 MW and 2000 MW, respectively. The Swiss data indicate that load-following is mostly used to minimise the load forecast error. An analysis showed that their load forecast error is size-independent, i.e. $\varsigma^{\mathrm{lfe,d}} = 0$, and does not show a significant load profile: The average standard deviation showed a rather constant variation, it was 0.9185 %, 1.0005 %, and 1.1958 % for 2013, 2014, and 2015, respectively. These values can be well-modelled with a load forecast error without size-dependence (see Figure 4.4c). It can be assumed that any load covering that is performed with load-following does not contribute to the load profile mismatches. It only contributes to the spontaneous load variation and the size-independent forecast error of an area.

Little can be said about the general implementation of load-following. Typically, AGC infrastructures[7] stemming from the former vertically integrated utilities are used to minimise the forecast error instead of putting any effort into forecasting techniques. As a consequence, the forecast error can deteriorate after abandoning load-following, for example, due to a loss the territorial sovereignty. The German BRP energy supply company *E.ON SE*,

[6] No intermittent generation which could add wind or significant solar power forecast errors.

[7] Although, AGC infrastructure can be used to implement load-following, it is not to be confused with real-time control, where a BRP uses real-time measurements to compensate for short-term forecast errors. This takes place if a BRP sets up a control structure to operate its individual load-frequency control, which is actually part of the TSO's responsibility. Thus, real-time control interferes with the TSO's responsibility, as the BRP exceeds its balancing responsibility. From a legal point of view, the precise demarcation between load-following and real-time control also depends on the real-time data a BRP uses, i.e. whether it is in line with the regulatory unbundling requirements.

which operated using load-following, had a deviation of roughly 1.1 % of the peak load of roughly 20 GW in 2003 [17]. After switching to schedule-based operation mid-2009, the German ACE quality instantaneously decreased.

4.2.4. Wind-Related Imbalances

A wind power forecast error depends not only on the weather forecast but also on the geographical dispersion and the number of wind turbines. Its forecast errors, in particular for non-specific locations, are often assumed to be normally distributed [17,32,94,95,135]. Lately, more sophisticated distributions such as beta, hyperbolic or Weibull distributions have been proposed to more accurately model the semi-heavy tails observed with typical statistical data [13,83]. In this thesis, a (generalised) hyperbolic distribution is assumed which does not only allow for a mean value and a standard deviation, but also for a skewness as well as a kurtosis (see Appendix D.3 for the mathematical derivation).

To obtain a general model, a given data set of standardised hour-ahead wind forecasting errors from six countries across Europe, including Germany and Spain, is analysed [83]. The investigation showed a good linear fit, which can be described by a regression coefficient and an intercept, of installed wind capacity $P_i^{\text{wind,tot}}$ to mean value μ^{wind}, standard deviation σ^{wind}, and kurtosis κ^{wind}, as illustrated in Figure 4.7. No significant relationship could be found for the skewness, which is assumed to be zero.

These standardised moments can be used to calculate the actual forecasting mismatch. For each country i, μ_i^{wind}, σ_i^{wind}, and κ_i^{wind} are a function of the actual wind production P_i^{wind} and the total installed capacity $P_i^{\text{wind,tot}}$ such that

$$f_i^{\mu,\sigma,\kappa}(P_i^{\text{wind}}, P_i^{\text{wind,tot}}) = \frac{a^{\mu,\sigma,\kappa} \cdot P_i^{\text{wind,tot}} + b^{\mu,\sigma,\kappa}}{P_i^{\text{wind,tot}}} \cdot P_i^{\text{wind}}. \tag{4.8}$$

In order to calculate P_i^{wind}, typical seasonal profiles are used, which were determined using historical load factors between 2009 and 2011 according to the PECD (see Section 4.1.1).

Such generalisation is subject to uncertainty: Notwithstanding the political ambition of the European Union as to the promotion of renewable energy, the national strategic and political endeavours vary: To what extent

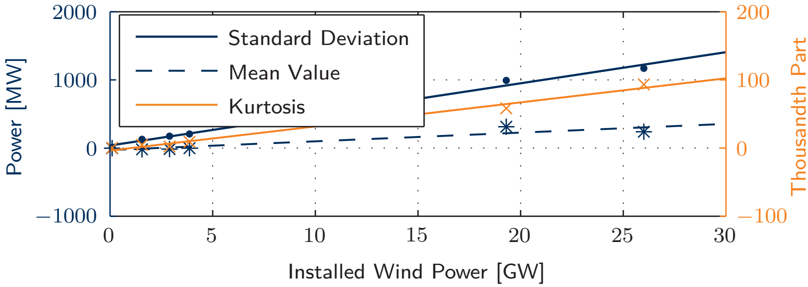


Figure 4.7.: Linear extrapolation to determine mean value, standard deviation and kurtosis of the hour-ahead wind forecast error as a function of the installed wind power capacity.

does this approach encompass changes in the forecasting quality? Spain and Germany are the countries with the largest share of wind power generation in Continental Europe, and they are considered to have assumed a vanguard role in dealing with the challenges associated with a high penetration of intermittent generation, which includes advanced forecasting experience and techniques. Therefore, the linearisation presented in Figure 4.7 is assumed to consider the increasing relative forecasting quality in a rudimentary way: The relative quality improves the more wind power generation is installed.

Wind Short-Term Variations

Brückl [17] and Dany [32] both stipulate that wind production in large areas does not significantly contribute to short-term variations, which are dominated by load behaviour. However, this assumption must be taken with caution. It implies wind-related imbalances do not occur spontaneously, which again does not mean that there is no impact on the frequency. The share of the wind forecast error that cannot be compensated by RR must be compensated by AGC resources. This is linked to the imbalance period as elaborated in Section 4.3.

4.2.5. Solar-Related Imbalances

The characteristics of solar power forecast errors have not been sufficiently studied yet, and they are neither completely random nor completely deterministic [95]. For the short-term variations, conformities to wind power forecasts exist during daytime. Under the assumption of the absence of heat storage for solar thermal power, solar power is negligible during the night, or, if such devices are present, they are perfectly controllable; therefore, the forecast error is assumed to be zero. Unlike for wind power, the degree of utilisation of solar power exhibits a distinctive daily and annual pattern: The solar power forecast error during daytime is assumed to be normally distributed as a function of the degree of utilisation. The mean value is zero. The scaling of the standard deviation is similar to that of wind power. For each country i, the standard deviation σ of the solar forecast error is a function of the solar power production P_i^{PV} and the total installed capacity $P_i^{\mathsf{PV,tot}}$ such that

$$f_i^{\sigma}(P_i^{\mathsf{PV}}, P_i^{\mathsf{PV,tot}}) = \frac{a^{\sigma} \cdot P_i^{\mathsf{PV,tot}} + b^{\sigma}}{P_i^{\mathsf{PV,tot}}} \cdot P_i^{\mathsf{PV}}. \tag{4.9}$$

Similar to the wind forecast error, typical seasonal profiles are used which were determined for each country from historical load factors between 2009 and 2011 according to the PECD in order to calculate P_i^{PV}.

4.2.6. Water-Related Imbalances

Water is also considered as a supply-dependent energy carrier. Theoretically, the forecast error from hydroelectric generation units can be modelled similarly to a (one-sided) wind forecast error. Usually only run-of-river power plants can be affected to any significant degree, as those units have very limited possibilities of storing water (hydropeaking), and therefore, of controlling the flow of water in an ideal way. Pumped-storage hydroelectric stations with a must-run inflow can also be affected to a minor degree, particularly in times of a high initial water stage and a continuing water inflow. Both can be solved by either an adjustment of the unit commitment of the respective BRP or by water overrun, i.e. letting the water pass by without producing electricity[8]. Both options offer the possibility of avoiding any overproduction, which is why in the literature the water-related forecast error of electricity production is assumed to be zero [32,116]. Also no relevant contribution to the net forecast error could be identified in Switzerland [10].

[8] Such behaviour generally conflicts with time-honoured operational practice of power plant operators and would not have been permissible under old concessions that did not foresee the possibility of an overproduction and negative prices of electricity.

4.3. Imbalance Period Assimilation

Up to now, imbalance modelling was based on historical values in systems which have a fixed imbalance period. But how can the behaviour be adjusted if the length of the imbalance period changes? Frunt et al. [67] as well as van der Veen and Hakvoort [151] discussed the imbalance settlement period as a design variable for market design. But for imbalance modelling a change in the imbalance period must be described in order to make it possible to adapt the energy balancing and frequency control responsibility. The impact on unit commitment of BRPs and outage behaviour can be considered a priori, as the imbalance period is a design variable for the decision process (see Section 4.1.1). But any impact on forecast errors must be considered a posteriori to general modelling, which means the model, which is based on historical data, must be adapted. In other words, the share of the imbalance that will be compensated (created) additionally by those BRPs with a shorter (longer) imbalance period needs to be described.

To evaluate the range of ancillary service impact of wind power plants, Parsons et al. [111] analysed wind power plant output fluctuations in the order of seconds to minutes. They concluded that shorter periods had a disproportional effect. Doherty and O'Malley [38] generalised these findings and concluded that for time periods less than one hour, the forecast error over minutes ($t^{\text{ibp}} = t$ minutes) is related to the standard deviation of the forecast error for a one-hour ($t^{\text{ibp}} = 60$ minutes) forecast horizon such that

$$\sigma_t = \sqrt{\frac{t}{60}}\sigma_{60}. \tag{4.10}$$

Under the assumption, that the share by which the forecast error is decreased or increased with a change in the imbalance period is fully covered by the BRPs, all forecast errors can be scaled according to Formula 4.10 such that

$$\sigma_t = \sqrt{\frac{t}{t^{\text{ibp}}}}\sigma_{t^{\text{ibp}}}. \tag{4.11}$$

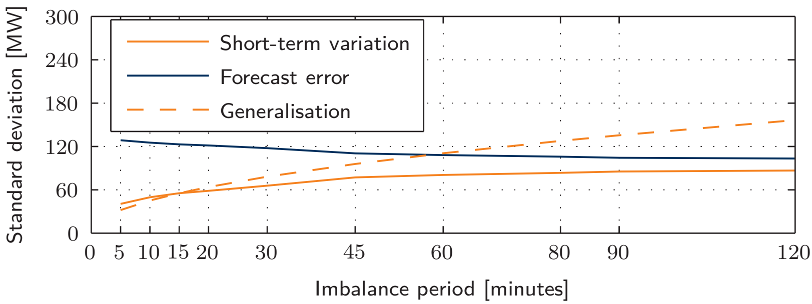
However, data required for a credible validation have not been available, but actual data did not falsify the assumption: Figure 4.8 summarises the findings. Figure 4.8a shows an analysis of Swiss data from 2010. The net imbalance is recalculated for different imbalance periods and split into forecast errors and short-term variations. This matches well for up to 20 minutes, which shows that the Swiss system is not consistently operated on a 15-minute basis (this is also related to reserve activation, see Section 4.4), otherwise both lines would be straight. They only straighten out after roughly 1 h, which proves again that the Swiss system has been dominated by an hour-based market design (in particular, before the introduction of the intraday market, see Figure A.3 on Page 176). Finally, Figure 4.8b plots the forecast error modelling not only against the actual load but also against the imbalance period; obviously the same can be done for the hour-ahead solar and wind power forecast error.

4.4. Activation Pattern of Replacement Reserves

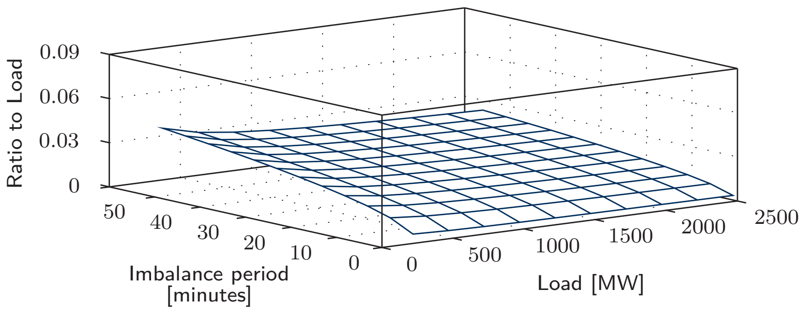
The ability to activate and the actual activation of RR determine to which extent expensive AGC resources can be substituted by usually cheaper manual reserves, as sharing the control task of FRR with RR changes the control resources and also the procurement costs[9]. From an operational point of view, the main advantage is associated with the deficit rate. A decrease in the deficit level means more security of supply, as the availability of fast automatic reserves is increased and the inadvertent exchange is lowered for the TSO, which translates into economic savings.

To activate RR, the TSO dispatcher has to take into account that manual reserves are only available with a time-delay, known as activation or reaction time, and are delivered to the power system for a certain duration called operating time. Operating time describes the minimum time that a generating unit must feed power into the system; thus, a reserve cannot be requested for a time interval that is shorter than its operating time. Obviously, the minimum operating time should not be shorter than the imbalance period (see Figure 2.8). If a TSO aims at compensating imbalances by RR, the interval over which the forecast error is calculated cannot be shorter than the total of the operating and activation time of the reserves

[9] The frequent activation of manual reserves might influence the market prices. Note that the energy price not only is a function of demand, but is also affected by other factors such as operational limits and generation fixed costs.



(a) An estimation of how net forecast errors and short-term variations change as a function of the imbalance period in Switzerland (dated 2010).



(b) The load forecast error as a function of the instantaneous demand and the length of the imbalance period.

Figure 4.8.: Summary of the impact of changes in the imbalance period.

called upon. However, there is no common framework for the activation of manual reserves in Europe. Current TSO regulations only recommend using manual reserves [104,106].

The most effective way to facilitate the frequent activation of manual reserves turned out to be a moving average-based approach using historical data. This was tested for both Switzerland and Continental European countries as shown in Figure 4.9.

Swiss control area: The best results could be obtained by activating RR based on the vertical median value of the last ten days. Applying this activation pattern consistently reduced the deficit rate by 45 % for the time considered, i.e. the months between October 2010 and March 2011 (a more comprehensive overview of the Swiss deficit level evolvement is presented by the author in [121]). Furthermore, the proposed pattern decreased control energy costs by about 30 %. Figure 4.9a illustrates the density function of AGC resources with and without the activation pattern. One can infer that any occurrence of positive AGC saturation, namely 400 MW, is significantly reduced. If FRR had been dimensioned based on the new deficit rate, the Swiss TSO could have reduced the FRR provision by up to 70 MW while maintaining the same deficit rate during the aforementioned months[10].

Continental Europe: Recordings of historical imbalances were not available for Continental Europe; however, the activation pattern could be evaluated for the ACE on a 15-minute resolution of several countries at LFC block level [29]. Figure 4.9b shows the results of a data analysis for 2012 which indicate a high potential, if the RR were to be used to avoid the occurrence of deterministic imbalance patterns, and load profiles in particular. The left and right ordinates refer to the optimum forecast horizon in days for each control block and the energy by which the ACE could have been improved for the optimum forecast horizon, respectively. This was done under the assumption that each control block had covered the forecasted amount by using 15-minute RR products. A negative difference in the net ACE energy

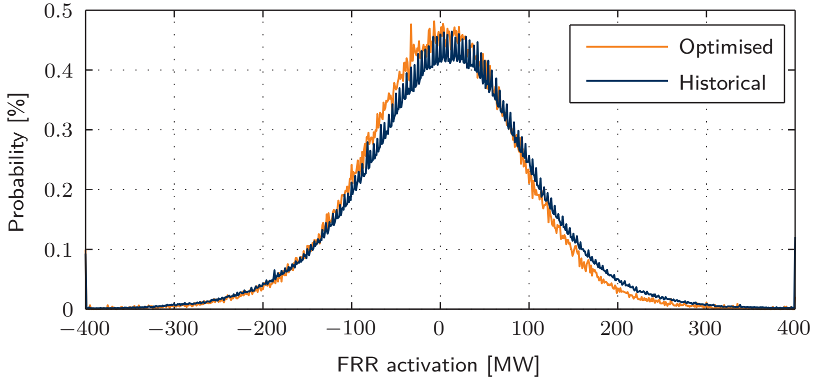
[10] The power provision of negative FRR is not affected since the negative saturations result mostly from re-dispatch procedures with neighbouring TSOs. Since it occurs randomly, the location estimator cannot predict it.

means an improvement, i.e. a reduction of the net ACE, whereas a zero or positive amount means a deterioration. For most of the control blocks, the best forecast is based on an 8 d to 15 d window. Note that an ACE forecast for Greece and Romania could worsen the ACE performance, as both do not exhibit predictable shares in their ACE behaviour. The results for Bulgaria as well as the SHB indicate a low potential for an additional forecast, i.e. these LFC blocks either have a low predictable share or an already efficient activation pattern for manual reserves. Covering the forecasted ACE shares in advance would reduce the ACE by approximately 15 % on average.

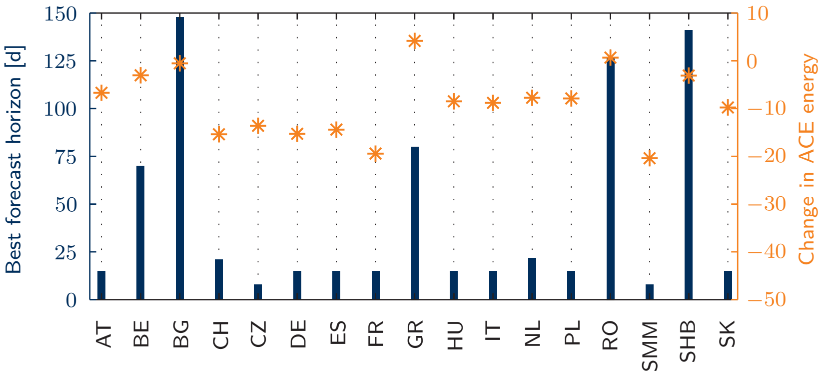
.

4.5. Overview of Imbalance Parameters

The above sections elaborated on the influencing factors that can cause a mismatch between demand and load. They all show a specific time-dependency and change over time. This behaviour can be captured by using Monte Carlo simulations. The scenarios discussed in Section 4.1.1 serve as input for generating random input from the probability distribution functions assessed in Section 4.2. These imbalances are aggregated to a net imbalance per area to which the concepts outlined in Section 3 are applied in the next chapter. Table 4.1 gives an overview of the influence factors that are described by statistical means. The impact of market-induced imbalances is determined based on the load profiles in each country. Its share depends on the deterministic degree of schedule-based operation of BRPs.



(a) Results of a Swiss AGC signal analysis between October 2010 and March 2011.



(b) Results of a Continental European ACE data analysis for 2012.

Figure 4.9.: Summary of forecasting market-induced imbalances based on ensemble-averaged profiles of the previous days of the AGC signal and ACE data of Switzerland and Continental Europe, respectively.

	Time-dependencey of error	Error distribution
Unit outages	Power plant portfolio, degree of utilisation	Poisson distribution
Load forecast error	Load profile	Normal distribution
Spontaneous load variation	Load profile	Normal distribution
Wind forecast error	Installed capacity, degree of utilisation	Hyperbolic distribution
Solar forecast error	Installed capacity, degree of utilisation	Normal distribution

Table 4.1.: Summary of the influencing factors discussed in the previous sections and described by statistical means.

5. Simulation and Analysis of Frequency Control Schemes

Based on the steps towards the centralisation of the frequency control framework outlined in Chapter 3 and the imbalance modelling elaborated in Chapter 4, the evolvement of frequency control by 2030 is simulated and discussed.
Parts of this chapter have been published in [123,124,128,130].

5.1. Initial Active Power Reserve Obligation

As this thesis aims at comparing the impact of different degrees of frequency control centralisation, a given degree of operational equity has to be assumed. Especially gate closure, the point in time where balancing responsibility passes over to the TSO, differs in various control areas. Therefore, typical parameters for dimensioning active power reserves are considered, which are power plant failure, short-term variations and forecast errors. To obtain a reference point for the amount of active power reserves available to the TSOs, the probabilistic dimensioning approach outlined in Section 3.4.2 is applied to each control area in order to determine the amount of FRR and RR. The distribution functions for describing the influencing factors are based on the imbalance modelling in Chapter 4, but only consider any time-independent information:

Unit failures: The statistics for unit outages can be found in Appendix B.2. Unit failures are calculated on the assumption that RR take over after $t^{\mathsf{FRR}} = 15$ minutes and that the BRPs compensate for the loss of power after $t^{\mathsf{FRR+RR}} = 1$ h on average, for example, by re-powering the lost unit or purchasing electricity from other available sources.

Spontaneous load variation: As discussed in Section 4.2.2, the spontaneous load variation relevant to reserve dimensioning can be linked to a reference load such as the peak load to omit time-dependency.

Load, wind, and solar forecast errors: According to the load characteristics, the load forecast error is split into a dependent and an independent share. For the wind and solar power forecast error, the standard deviation can be derived directly from the installed capacity to omit time-dependency [33,38]. This results in an average standard deviation of 3.7 % for the wind forecast error. The solar forecast error is described in the same way, but with the difference that a solar forecast error is zero at night-time; on average, it can only occur 50 % of the time. As the dimensioning is done for a steady state consideration, all forecast errors are modelled by normal distributions. Under the assumption that RR is regularly activated on a 15-minute basis, the real-time share of the forecast errors in the scope of FRR is 50 % (see Formula 4.10).

The standardised winter measurements from the ENTSO-E Statistical Yearbook 2011 [45] serve as a reference for parameterising the model in Section 5.2.1. These values are also high load values, but not necessarily peak loads. Based on F^{FRR} and $F^{\mathsf{FRR+RR}}$, the required amount of active power reserves is determined. A symmetric deficit probability is assumed for negative and positive reserves so that $p^{\mathsf{def+}} = p^{\mathsf{def-}} = 0.05\,\%$, i.e. $p^{\mathsf{def}} = 0.1\,\%$. The results of active power reserve dimensioning are shown in Figure 5.1. Note that this approach is in line with practical reserve dimensioning approaches that actually are approved by national regulatory authorities [9,10,30,77].

Values for positive reserves, mainly RR, are higher, as unit failures lead to negative imbalances only. This effect is more significant in areas with a high amount of large units. Nonetheless, the difference between negative and positive reserves in each area is quite small, which emphasises the fact that active power reserves are mainly used for continuously occurring imbalances as elaborated in Section 2.3.3. The larger the area, the lesser the influence of unit outages, as the overall amount of reserves exceeds the largest unit many times over; whereas in case of a small area the maximum amount of positive reserves is mostly determined by the largest unit.

It is worth pointing out that in some areas the calculated values are significantly higher than the amount actually purchased; this is true for FRR in particular, although very optimistic values with regard to forecast errors and variations were taken into account. This is because a probabilistic approach

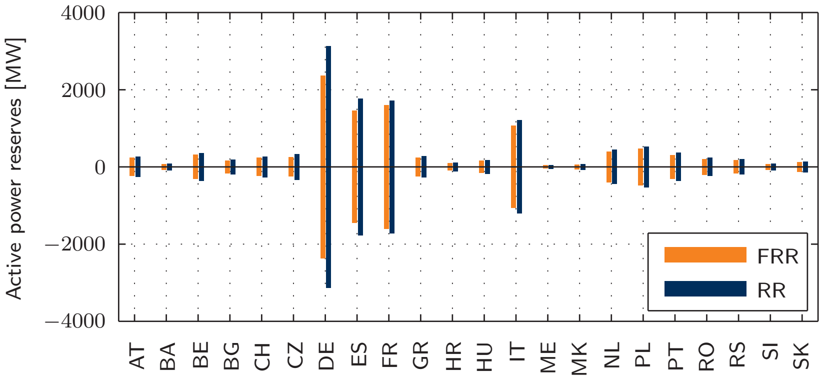


Figure 5.1.: Amount of positive and negative values of FRR and RR required per country for a decentralised structure in Continental Europe based on a total deficit probability of $p^{\text{def}} = 0.1\,\%$.

aiming at a total deficit probability of $0.1\,\%$ is not applied. These areas generally rely on the square-root formula (see Formula 3.39). For investigating the difference between a probabilistic approach and the square-root formula for determining the required amount of FRR, the amount of reserves as a function of peak load is of interest. Figure 5.2 shows the symmetric share (probabilistic calculation without unit failures) of FRR for both approaches.

The results of the probabilistic calculation partly correspond well to those arrived at by the square-root formula; the difference exhibits a standard deviation of 401 MW where the square-root formula always results in lower values. Subsequently, the square-root formula can be used to estimate the results of the probabilistic calculations for the current situation by updating its parameters. Hence load predominantly defines the required amount of reserves. The outliers Germany and Italy in Figure 5.2 are due to a high penetration of intermittent sources. In these countries, it is not load, but the share of intermittent sources that is the main driver for the required amount of reserves, an effect that will also apply to other countries in future. The square-root formula is not a future-proof dimensioning requirement, despite the fact that it is used by most countries. This confirms earlier studies that investigated the limitations of load-related and deterministic reserve dimensioning approaches [156].

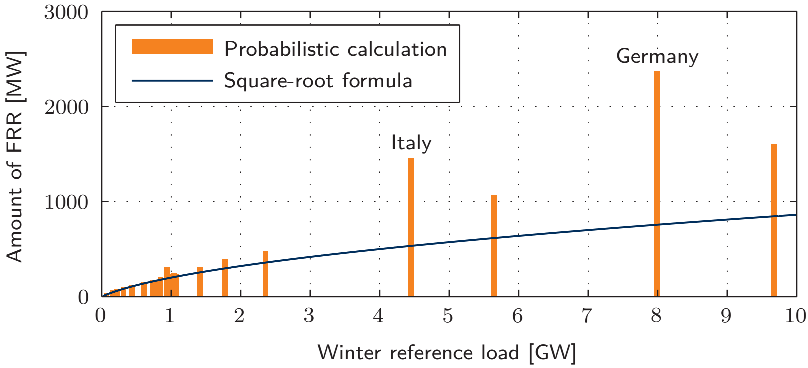


Figure 5.2.: Comparison between probabilistic approach and square-root formula for 2011.

5.2. Status Quo Analysis

In the following, the model introduced in Section 4 is validated and, in order to determine the initial amount of active power reserves, parameterised. Furthermore, the improvements of the K-factor calculation presented in Section 3.4.1 are evaluated. The latter allow a better determination of an area's imbalance and can also be implemented in the current framework without centralisation.

5.2.1. Model Validation

First of all, the model is parameterised to ensure results of practical significance. Based on the initial dimensioning done for 2011, the validation focuses on the years 2012 to 2014. As discussed in Section 3.4.2, countries are free to dimension their reserves according to national and non-standardised rules. The deficit level can be chosen individually by each TSO, and the amount of reserves as proposed in the previous section will not necessarily represent actual dimensioning practices. This leaves two main degrees of freedom: The overall amount of local active power reserves as well as their division into FRR and RR. To adapt the overall amount determined in Section 5.1, the frequency distribution within the time frame for which the sum of RR and FRR was dimensioned is matched against the estimated

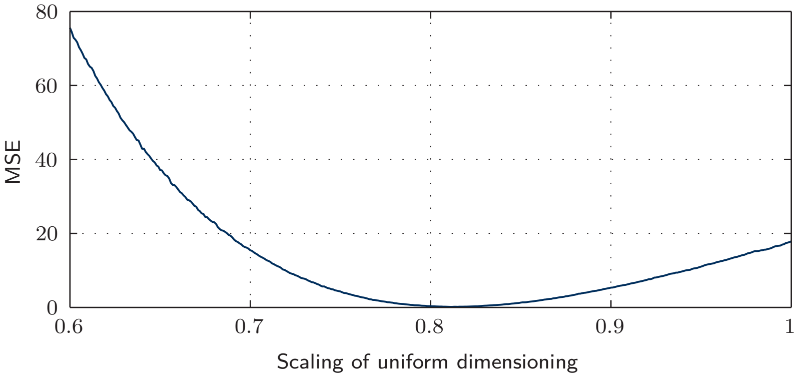


Figure 5.3.: The MSE as a function of the scaled total reserves based on an hourly matching of modelled and historical frequency measurements between 2012 and 2014.

frequency. Figure 5.3 shows the Mean Squared Error (MSE) as a function of the scaled total reserves based on an hourly matching of modelled and historical frequency measurements between 2012 and 2014. The total amount of the uniformly dimensioned reserves needs to be scaled using a factor of 0.81 to obtain the best match. In other words, scaling the sum total of RR and FRR ensures that the amount of reserves is adequate for matching the frequency behaviour. The dimensioning assumes a symmetric deficit for FRR and total reserves; thus, both are equally downsized, which results in a sum total of FRR for all 22 countries of ±7.2 GW, which is an amount comparable to the actual dimensioning.

Share of Market-Induced Imbalances

Intra-hour imbalances are characterised by spontaneous load variations and the stepwise matching of load profiles. The latter is defined by the share of schedule-based operation of BRPs, which creates a highly predictable imbalance pattern. To investigate the extent to which system operation is exposed to schedule-based operation, two scenarios are analysed:

Adherence to local imbalance period: As depicted in Figure 2.5, imbalance periods differ across Continental Europe. This defines the shortest standard product in each country. Assuming sufficient market liquidity, some BRPs manage their load coverage strictly according to the imbalance period. Besides short-term variations and forecast errors, they will also cause market-induced imbalances. All other BRPs operate in a load-following mode and only contribute to short-term variations and forecast errors. This is a best-case scenario.

Domination of hourly products: As discussed in Section 2.3.3, the European market is dominated by hourly standard products. As shown in Appendix A.4, intraday markets currently have a low liquidity of 10 % of the day-ahead volume at most, and today's day-ahead markets only offer hourly products[1] [29,55]. It can be assumed that 90 % of schedule-based operation is done on an hourly basis, whereas load-following BRPs behave as in the best-case scenario. This is a conservative-case scenario.

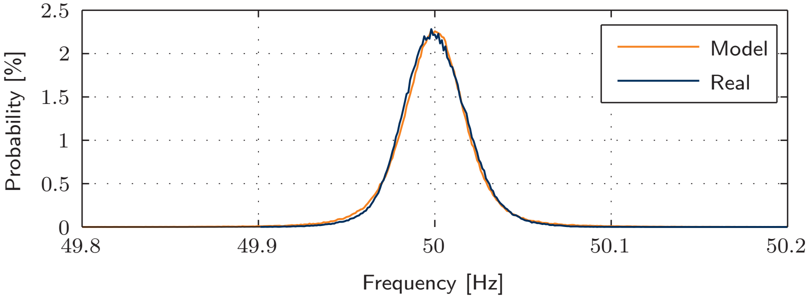
The model matches both scenarios. The degree of schedule-based operation is used as the fitting objective. In this way, the range of schedule-based operation can be estimated (see Appendix C.1). The results are summarised in Table 5.1. The resulting frequency distributions for 2014, as shown in Figure 5.4, indicate a good match between model and reality. The share of schedule-based operation that affects frequency quality is estimated to have been between 0.17 % and 0.25 % in recent years. The decrease does not mean that schedule-based operation decreased, but that measures to cope with these deterministic imbalances have been taken (see Section 5.2.2). The values for both scenarios are close together, i.e. hourly schedule-based operation vastly dominated frequency quality, and a small share of quarter-hourly schedule-based operation has only minor impact. These observations are in accordance with previous discussions: For the European system, Weißbach and Welfonder [160] estimated that roughly 20 % of energy balancing during the years 2006 and 2007 was conducted on an hourly basis.

But how well does the model fit the historical temporal evolvement and the pattern of market-induced imbalances? The extent to which TSOs incentivise BRPs to properly implement the operational rules for schedule changes is limited, as discussed in Section 2.3.3. The operational implementation is up to the BRP and the respective operators intending to reduce the deterioration of their units. The actual behaviour is a mixture of both the adherence to operational rules and the physical limitation of

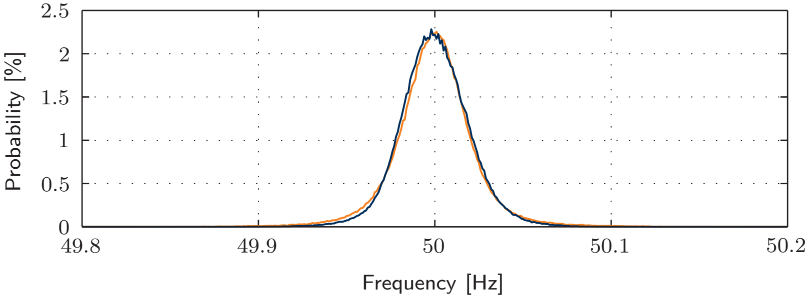
[1] Also see the discussion of the Swiss system and the trading opportunity of adjacent markets in Appendix A.2.

	2012	2013	2014
Best-case scenario	23 %	24 %	17 %
Conservative-case scenario	25 %	25 %	18 %

Table 5.1.: Resulting share of scheduled-based operation for fitting modelled and historical frequency distributions between 2012 and 2014.



(a) Distribution of yearly frequency in a best-case scenario with an 18 % share of schedule-based operation in 2014.



(b) Distribution of yearly frequency in a conservative-case scenario with an 17 % share of schedule-based operation in 2014 (same legend as in Figure 5.4a).

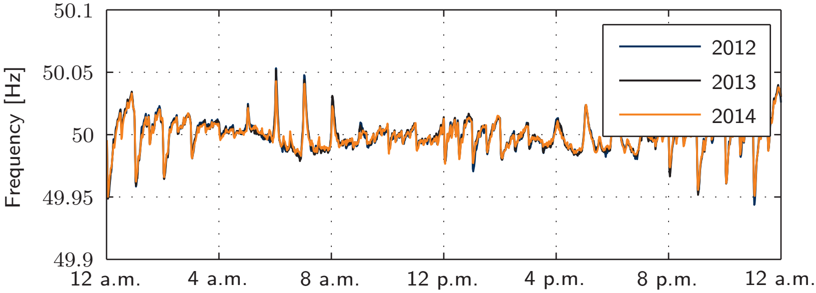
Figure 5.4.: Frequency validation for 2014.

the power plants involved. However, the physical limitation of the current total generation portfolio does not limit the ability to instantaneously, i.e. within one minute, follow discrete schedule changes instead of linearly adjusting power output (see Table C.1 and Table C.2 in Appendix C.3). The real behaviour is in-between no ramping and ramping according to the ramping period. Figure 5.5 shows the resulting behaviour in 2014. Figure 5.5b and Figure 5.5c show the ensemble-averaged daily frequencies of both scenarios. Without ramping both scenarios overestimate the peaks in the morning hours, but underestimate the same with ideal ramping. The underestimation demonstrates that a large amount of providers and BRPs do not implement operational ramping according to the stipulated European-wide ramping period. The reasons for the overestimation, on the other hand, can be threefold. First, several TSOs have additional measures in place to limit the magnitude of hourly schedule changes, for example, the Italian TSO can split hourly schedules into quarter-hourly steps to limit the discrete changes in the morning and evening. Second, the modelling of the load profiles assumes perfect synchronisation of ramping and load behaviour; in reality, the peaks can slightly differ from day to day, which can result in a lower average yearly peak. Third, the use of RR has not been considered yet. This is in accordance with the observations made in Section 4.4, i.e. TSOs seem to have a limited awareness of the deterministic nature of load profiles and do not proactively activate manual reserves; however, this cannot necessarily be taken for granted in extreme morning hours.

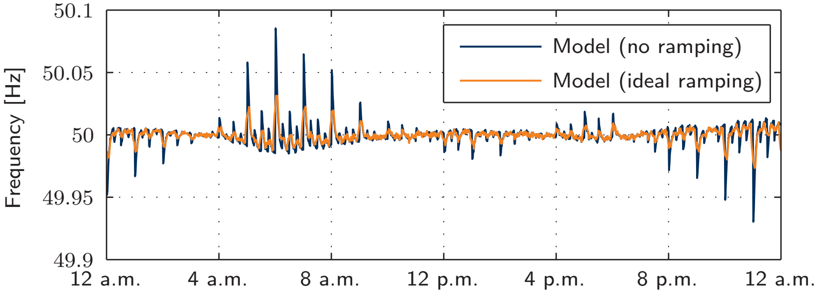
To summarise, the results demonstrate a very good match between simulated and historical frequency behaviour. Notwithstanding any country-specific differences in market structures and ancillary service products, the imbalances that Continental European TSOs need to compensate for can be well-identified and modelled in a way that highly corresponds to reality.

5.2.2. Potential of Proactive Manual Reserve Activation

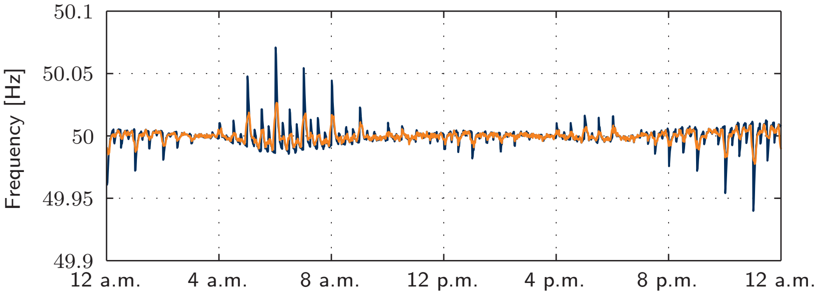
In the section above, it was assumed that RR are only used to cover forecast errors and unit outages. Often additional reserves are available, but are not used to anticipate market-induced imbalances. Can frequency quality be improved by progressively activating manual reserves? In the following, it is assumed that whenever RR are available, they are used to compensate the market-induced load profile. The challenge is that TSOs need information



(a) Ensemble-averaged daily frequency of 2012, 2013, and 2014, which are all very close together.



(b) Ensemble-averaged daily frequency modelled for 2014 in a conservative-case scenario.



(c) Ensemble-averaged daily frequency modelled for 2014 in a best-case scenario (same legend as in Figure 5.5b).

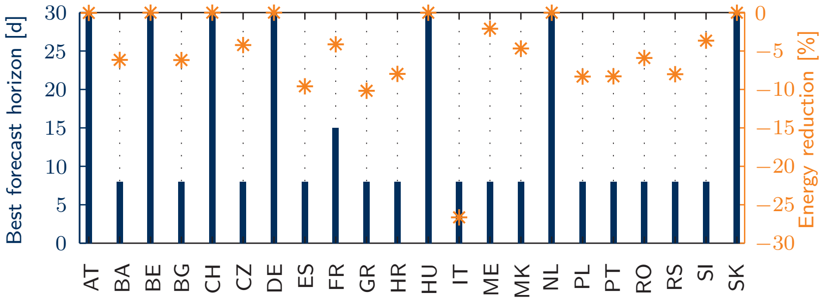
Figure 5.5.: Evaluation of matching of conservative and best schedule-based operation.

on the origin of the imbalance; if they cannot differentiate between load-related imbalances and generation-related imbalances, their forecasting is vastly biased. Typically forecast errors caused by intermittent generation can be isolated, as its sources are equipped with metering devices and often assigned to a designated BRP. It can be assumed that TSOs can perform forecasting based on short-term historical load variations. Figure 5.6 shows the potential improvement achieved by proactive activation of manual 15-minute reserves, i.e. RR. Figure 5.6a explicates the prediction of short-term variations in a best-case scenario (see Section 5.2.1), which reveals no improvement for countries with an imbalance period of 15 minutes, as the deterministic share in these countries has a higher resolution and cannot be covered by 15-minute RR. The forecast horizon could be reduced if the historical load profile was known (which is not realistic). The relative share of the total imbalance is small, but impact on the deterministic share of frequency quality is significant, as illustrated by Figure 5.6b. The deterministic pattern persists, but in a range that is roughly 10 times smaller: Market-induced imbalances that cannot be covered with the help of manual reserves have to be compensated using AGC actions, which are reactive, and thus will not cover the full imbalance.

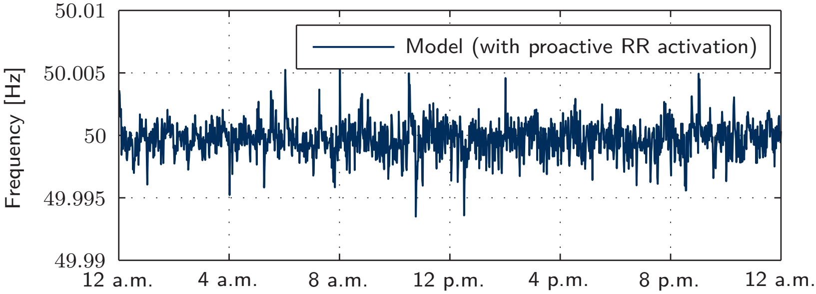
The observations on proactive manual reserve activation confirm the observations made in Section 4.4. Most TSOs cover market-induced imbalances with (limited) AGC resources, although a prediction is possible. The longer the imbalance period, the easier it is to predict the resulting zigzag-shaped mismatch; however, two aspects need to be noted:

- The design of the RR market should match the BRP's ramping behaviour. For example, in Switzerland, RR have an activation time of 15 minutes, but the ramping is up to the service provider. This does not match the incentives given for a linear progression of schedule changes. This leads to an additional imbalance in case RR are activated, as AGC interprets an RR activation as an imbalance (part of P^{phys}, see Section 3.2.2). If the BRP's adherence to linear ramping is taken for granted, schedule-based activation is the straightforward solution to avoid additional triggering of AGC: The additional power is equal to an intentional change in power (part of P^{phys} and P^{set}).

- The use of manual reserves can only disaggregate the zigzag-shaped mismatch into smaller zigzag-shaped mismatches, and no improvement is possible if the minimum duration of an RR activation is



(a) Results based on historical short-term variations, i.e. the load profile is not known.



(b) Ensemble-averaged daily frequency if RR are activated based on the ensemble-averaged profiles of the previous days according to the numbers in Figure 5.6a.

Figure 5.6.: Summary of forecasting market-induced imbalances based on ensemble-averaged profiles of the short-term imbalance of the RGCE of the previous days (best-case scenario).

shorter or equal to the imbalance period on basis of which market-induced imbalances occur. RR have been designed to compensate large and persistent mismatches. Profile-shaped reserve products ("ramping products") are not an appropriate option, as long as the market products remain discrete; however, the imbalance period can be reduced in order to shift more responsibility to the BRPs and their market activity (see Section 5.3.1).

5.2.3. Evaluation of Bias Factor Calculation

Implementation of Bias Factor Algorithms

In the following, the influence on Switzerland of a specific outage in the RGCE of around 1200 MW that happened in 2010 is evaluated. The proposed sizing methods in Section 3.4.1 as well as the standard OpHB values are applied in the reduced power system model (see Appendix B.1):

OpHB definition: In order to have a baseline for measuring any improvement, K-factors as well as FCR and β were taken directly from ENTSO-E instructions.

Updating c_i and scaling β: The algorithms described on Page 77 were implemented for time intervals of 12 a.m. to 8 a.m., 8 a.m. to 8 p.m., and 8 p.m. to 12 a.m. The amount of generation during these time intervals was calculated by adding each area's export power flow to its load, since detailed generation data are not published by the ENTSO-E.

Simple construction by parts: Simple construction by parts refers to the calculations presented on Page 78. It involves applying the definition of β to a single area of the same time-intervals as were used for the calculations of c_i and β above.

Non-linear construction by parts: Using non-linear speed droop as proposed on Page 79 differs from simple construction by parts through the consideration of more accurate load self-regulation measurements and non-linear FCR speed droops. For the latter, it is assumed that the specifics of the dead bands and the full activations are known for FCR providers.

Comparisons of the effect of the different K-factor calculation methods are shown in Figure 5.7. The summary of the performance of the different

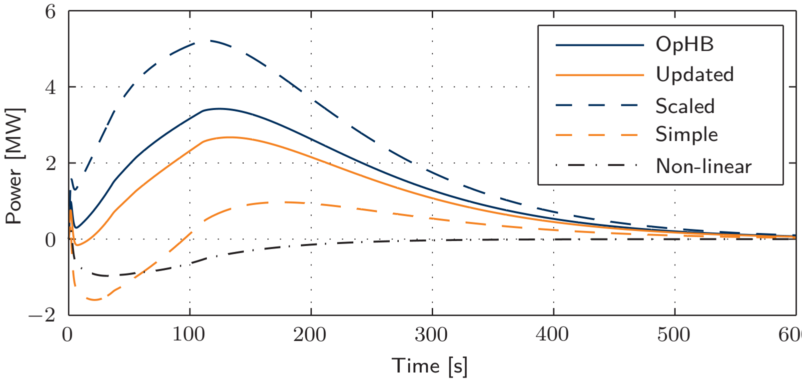
K-factor calculation methods is shown in Figure 5.8. The size of the area spanned is inversely proportional to the performance of the corresponding algorithm. The values of interfering and supporting AGC serve as an indication as to how much FRR was triggered as a result of the disturbance. The maximum value of the ACE and its integration over time are measurements for the mismatch between the area's actual β_i and the AGC's bias factor.

Discussion of Algorithms

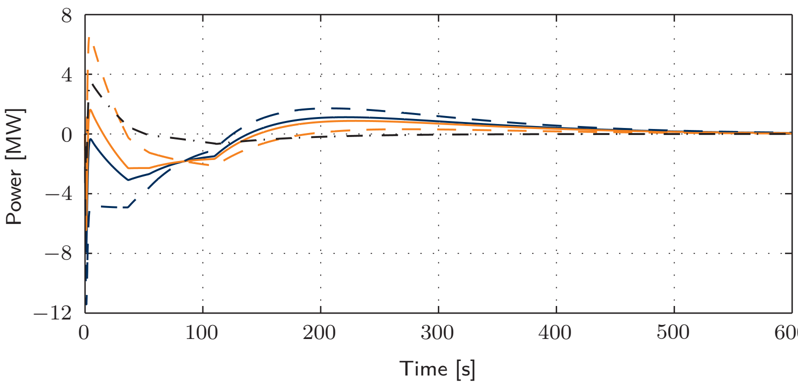
It can be seen that more sophisticated algorithms lead to better overall performance, which is clearly desirable from an economic point of view, as inadvertent exchange can be reduced and the principle of non-interactive control can be adhered to more closely. However, single disturbances such as outages have a comparatively small effect. The updated c_i method is closest to the OpHB method; it behaves very similarly, but achieves less activation of active power reserves. The best performance is achieved by the non-linear methods. These more complicated methods reflect the underlying properties of the system more closely. Due to progress in computation power and communication, the tools for implementing such improved algorithms already exist. The outlined methods can be used as a basis for an in-depth investigation of the differences between the methods proposed. Without further studies based on a more detailed assessment of data available to the different TSOs, it does not seem prudent to suggest a final choice as to which method could replace the current one. To apply the benchmarking simulation model, points in time for which the system's frequency-response characteristic is known must be found. This is becoming increasingly difficult due to the vast degree of interconnections in the RGCE. And yet the AGC scheme as well as its coupling will function even if the K-factor settings are not accurate. However, an accurate determination of an area's frequency-response is desirable for AGC couplings: In this thesis, the imbalance modelling is idealised, i.e. the imbalance is fully known, but in reality, it is necessary to have information on an areas's frequency characteristic in order to determine the local imbalance.

5.3. Potential of Centralisation and Harmonisation

This section discusses the steps towards a centralised frequency control setup. In this context, the effect of harmonising the imbalance period, which is a major driver of imbalances, is also briefly discussed.



(a) AGC output for different frequency bias factor algorithms.



(b) ACE output for different frequency bias factor algorithms (same legend as in Figure 5.7a).

Figure 5.7.: ACE and AGC output for different frequency bias factor algorithms.

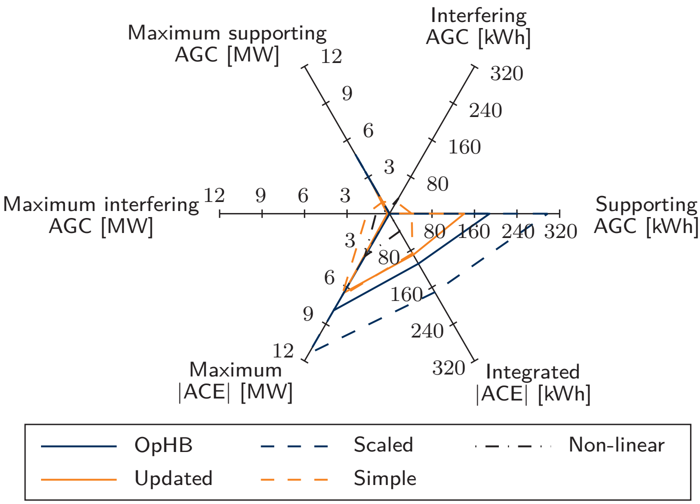


Figure 5.8.: Comparison of the performance of the different frequency bias factor algorithms.

5.3.1. Impact of Reducing the Imbalance Period

After validating the model (see Section 5.2.1) and discussing the challenges presented by market-induced imbalances and non-harmonised imbalance periods (see Section 5.2.2), the impact of changing the imbalance period is discussed. A harmonisation of the imbalance period offers several advantages. For example, system-destabilising trading loopholes between adjacent markets with different imbalance periods can be avoided and markets can be harmonised. In the scope of frequency control, two main opportunities are provided if the imbalance period is shortened:

- The impact of market-induced imbalances can be reduced or the share of schedule-based operation can be increased without decreasing frequency quality.

- With shorter forecasting intervals, more balancing responsibility is given to the BRPs. Together with financial incentives that lead to a high liquidity of standard products of a duration equal to the imbalance period, schedule-based operated BRPs will have less of a

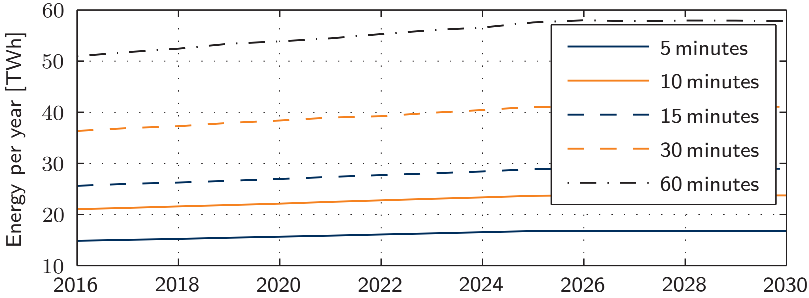


Figure 5.9.: The net absolute energy between 2016 and 2030 that will need to be compensated as a function of the imbalance period in the scope of frequency control; under the assumption that BRPs make use of the shortest standard products available.

deteriorating impact on frequency quality.

The assumption of the latter aspect needs to be addressed in market design: If BRPs do not make use of shorter products for load covering, there will be no improvement in terms of frequency quality, as this will not bring about a change in today's dominance of hourly products. A harmonisation of the imbalance periods in Continental Europe is currently the subject of political discussion in the course of drafting the Network Codes; periods of 30 and 15 minutes are currently considered [2]. Harmonisation across Europe is mainly a matter of costs for upgrading scheduling and accounting systems as well as new metering devices. In the case that cross-border capacity is auctioned explicitly, the available products have to be adapted accordingly (in case of market coupling this is done implicitly). As standardisation rollout is likely to take place step-by-step, market compatibility can be granted if the harmonised imbalance period is a divider of 60, i.e. 30, 15, 10, or 5 minutes. The current ramping period can be applied up to an imbalance period of 10 minutes. In this case, a transition takes place and operational schedule changes will turn into continuous ramping. Note that for any length of imbalance period, the above-mentioned aspects for ramping restrictions should be considered (see Section 2.3.3).

Figure 5.9 illustrates the evolvement of the absolute energy that needs to be compensated by Continental European TSOs up to 2030. In particular, the increasing level of intermittent generation will inherently lead to

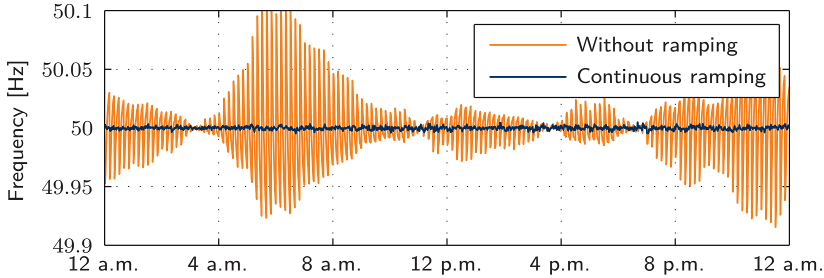


Figure 5.10.: Extreme situation of a 100 % share of schedule-based operation with an imbalance period of 10 minutes using 2016 as an example (no changes in the amount of reserves).

larger deviations. Although forecasting techniques could improve disproportionally, the advantage for TSOs is obvious. A European-wide harmonisation to 30 minutes has only minor impact, but a reduction to 15 minutes could largely reduce the energy that needs to be compensated by frequency control actions. From a load point of view, 10 minutes best matches with the current ramping period, which is also 10 minutes. This can be shown by a sensitivity analysis of a situation involving extreme values. Figure 5.10 shows the ensemble-averaged daily frequency of a 100 % schedule-based operation with $T^{\text{ibp}} = 10$ minutes and both $T^{\text{ram}} = T^{\text{ibp}}$ as well as $T^{\text{ram}} = 0$ minutes. The latter is obviously provoking high frequency deviations, whereas with continuous ramping commitment, deterministic frequency deviations can be avoided. Note that the shorter the imbalance period, the higher the energy difference between schedule value and real power profile, and therefore, the more important to consider this in the imbalance energy reference calculation (see Formula 2.6 on Page 42).

By shortening the imbalance period and combining it with proper ramping incentives, the highly correlated[2] deterministic imbalances in a synchronous area can be reduced. For stochastic imbalances, AGC coupling is an effective measure to reduce frequency control resources.

[2] This correlation could only be weakened if control areas with different load profiles or in different time zones are located in the same synchronous area. In the RGCE, only Portugal has a time shift of one hour, which is not enough to make a significant difference when it comes to market-induced imbalances.

5.3.2. Potential of Imbalance Sharing

In the following, the potential of imbalance sharing in the Continental European transmission system is evaluated.

Transfer Capacity Assessment

Figure 5.11 presents some performance indicators for the imbalance sharing process in 2015 and 2030 (the commissioning of new tie-lines is not considered). The general behaviour does not change for either small (peak load below 10 GW) or large (peak load above 10 GW) areas. The sharing effect will increase in 2030 due to the penetration of intermittent generation. In both years, the conservative unidirectional transfer capacity represents the greatest limitation. Expanding the use of the TRM for imbalance sharing, on the other hand, allows profiting from 94 % of the full imbalance sharing potential in 2015 and 92 % in 2030. This number needs to be viewed with caution, as the TRM is not necessarily sized according to Formula 4.1 on Page 94 in reality.

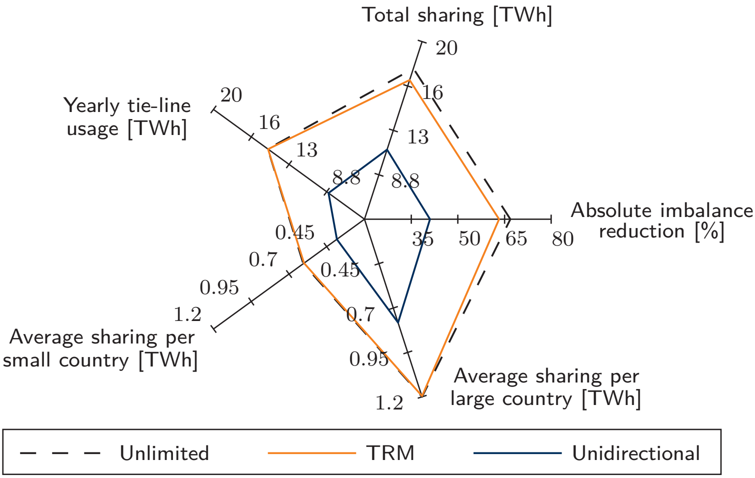
Comparing Distribution Rules

In Section 3.3.1, three distribution rules for imbalance sharing, i.e. uniform pro-rata, inverse proportional, and proportional, were introduced. Figure 5.12 compares these rules; and their behaviour confirms the results of the qualitative evaluation (see Table 3.1 on Page 67). The difference between uniform pro rata and inverse ratio is small. Small areas have smaller imbalances which can often be fully balanced by the imbalance sharing process with any remaining shares being used by large countries. The results for a distribution proportional to the imbalance differ significantly, as large areas have a larger potential; the chance of fully balancing large areas and having a remaining share for small areas is comparatively small.

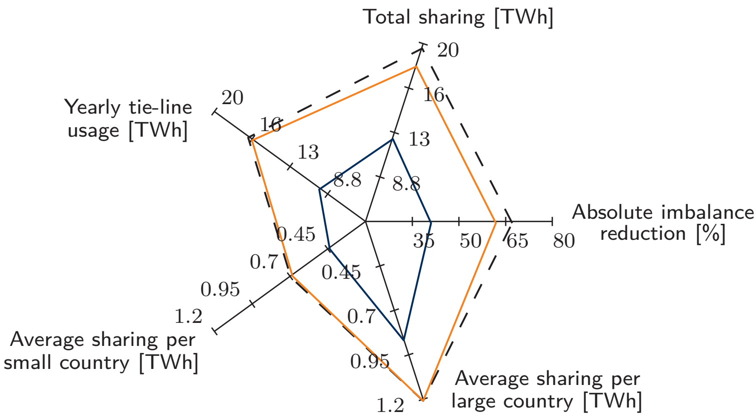
As mentioned above, imbalance sharing is most effective if the imbalances in the participating areas do not strongly correlate; however, market-induced imbalances typically occur simultaneously in different areas. These rather deterministic shares can basically only be shared by way of large stochastic imbalances, i.e. intermittent generation. In times where imbalances have the same sign, reserve sharing can assist TSOs.

5.3.3. Potential of Reserve Sharing

In the following, the potential for reserve sharing in the Continental European transmission system is evaluated. Reserve sharing is applied together with imbalance sharing. Imbalance sharing reduces the available transfer capacity, which limits the possibility to share reserves; and the same trans-



(a) Imbalance sharing process evaluation for 2015.



(b) Imbalance sharing process evaluation for 2030 (same legend as in Figure 5.11a).

Figure 5.11.: Yearly results of the imbalance sharing process in the RGCE with different transfer capacity limits ($t^{\text{ibp}} = 15$ minutes in all areas).

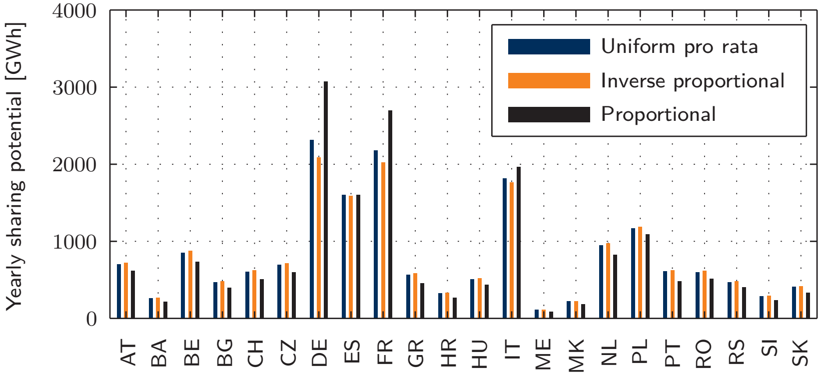


Figure 5.12.: Comparison of the three distribution rules for an evaluation of 2014.

fer capacity assessment is used for imbalance and reserve sharing, although reserve sharing can only use the capacity that has not been used for imbalance sharing. Note that both kinds of sharing need capacity in the same direction, i.e. imbalance and reserve sharing cannot cancel each other out.

Figure 5.13 presents some performance indicators for the reserve sharing process in 2015 and 2030 (for illustration purposes the same characteristics apply in 2030 as in 2015). Unlike imbalance sharing, there is no imbalance reduction (the absolute imbalance stays the same). Instead, the reduction in the deficit level, i.e. time of depleted FRR, is evaluated. Albeit the total reserve sharing is small compared to the imbalance sharing, the deficit level can be significantly reduced for both small and large areas (same distinction as in Section 5.3.2). Moreover, the sharing effect increases in 2030 due to the penetration of intermittent generation. Notwithstanding the limitations of the conservative unidirectional transfer capacity assessment, the total reserve sharings in the different capacity availability scenarios are of comparable size. This is due to the fact that the higher the capacity limitations for imbalance sharing, the higher the potential for reserve sharing, i.e. imbalance sharing relies on opposing imbalances, whereas reserve sharing can access the available reserves in all areas.

As with imbalance sharing, the absolute numbers are significantly smaller, since reserve sharing is only used to increase the control resources in case a TSO's local reserves are exhausted. Note that expanding the use of the TRM for reserve sharing cannot be taken for granted: Reserves are a procured product and compete with wholesale products for which transfer capacity needs to be (implicitly or explicitly) auctioned. In this context, reserve sharing can be seen as a MEAS. This does not apply if reserve sharing is used to find and activate the cheapest reserve in a synchronous area (see Section 3.3.2) or in case of common reserve dimensioning, which is discussed in the next section.

5.4. Long-Term Frequency Quality Evolution

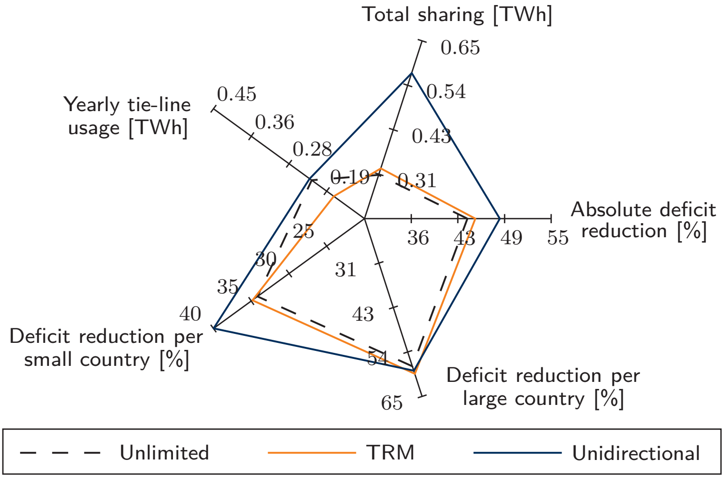
In the following, the impact and the evolution of long-term frequency control quality of the RGCE is investigated. In this section, preference is given to a simulation with an hourly time resolution in order to investigate the sensitivity of the total amount of active power reserves and the performance of the time control process. With this approach, the division between manual and automatic reserves as well as the degree of liberalisation is decoupled from long-term frequency control quality, i.e. the ability of the entire system to compensate for an imbalance.

Steady State Consideration

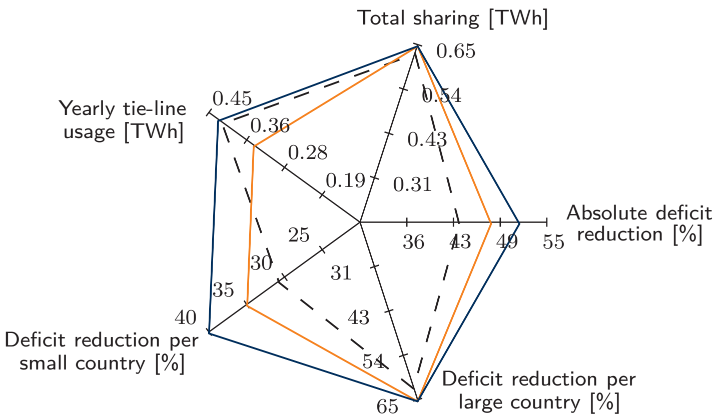
5.4.1. Effect on Time Error Correction

The electrical time deviation is a robust indicator for the overall trend of the frequency quality: One might speculate that the accumulated time error should oscillate within certain boundaries with a mean value close to zero. However, the results illustrated in Figure 5.14 show a different trend. A clear negative drift of the accumulated time error is observable for both scenarios. A significant time difference is expected for Scenario 2 with a time error of 5.4 h by the end of 2030. The negative time drift implies an average frequency below the nominal value, which is mainly caused by an overestimation of wind and solar power production. Until 2020, both scenarios exhibit a similar time difference. After that, the scenarios start to drift apart. It can be concluded that the time difference will increase with the expansion of wind and solar power capacity if the reserve resources are not adjusted accordingly.

As a consequence, one needs to investigate the extent to which time control is able to avoid such a long-term energy mismatch within the system. Figure 5.15 summarises the resulting performance of time control by end



(a) Reserve sharing process evaluation for 2015.



(b) Reserve sharing process evaluation for 2030 (same legend as in Figure 5.13a).

Figure 5.13.: Yearly results of the reserve sharing process in the RGCE with different transfer capacity limits (parameters according to the best-case scenario without any future changes).

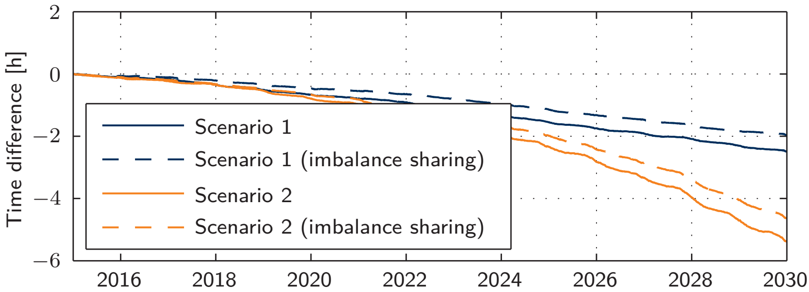


Figure 5.14.: Time error analysis (without the activation of time control and without changes in the reserve procurement).

of 2030. Both scenarios exhibit a comparable and low average time error, which indicates a stable average frequency. However, staying under the maximum target discrepancy cannot always be ensured. Scenarios 1 and 2 exceed the limit of $\pm 30\,\mathrm{s}$ for 48 and 411 days, respectively. Obviously, Scenario 2 challenges time control the most; negative time correction in particular increases significantly.

5.4.2. Active Power Reserve Sensitivity

So far, no changes in the amount of active power reserves were assumed, as the dimensioning typically is static. As shown above, the frequency quality will change significantly in the coming years if the amount of active power reserves is not adjusted. The necessary increase in active power reserves to ensure a stable standard frequency deviation of 10 mHz, i.e. the hourly standard frequency range, is shown in Figure 5.16. Only the assessment of the unidirectional transfer capacity scenario is considered, as this is the only approach which does not interfere with market-related capacity allocation (see Section 4.1.2). In Scenarios 1 and 2, the active power reserves need to be increased by 1.2 % and 6.0 % a year on average, respectively, if there are no sharing processes. To cope with Scenario 2, the active power reserves need to be increased by 83 % by 2030. Imbalance sharing can help reduce the increase in reserves; Scenario 2 profits slightly more from imbalance sharing. With reserve sharing, the required amount of reserves decreases significantly; however, these numbers need to be viewed with caution; as it

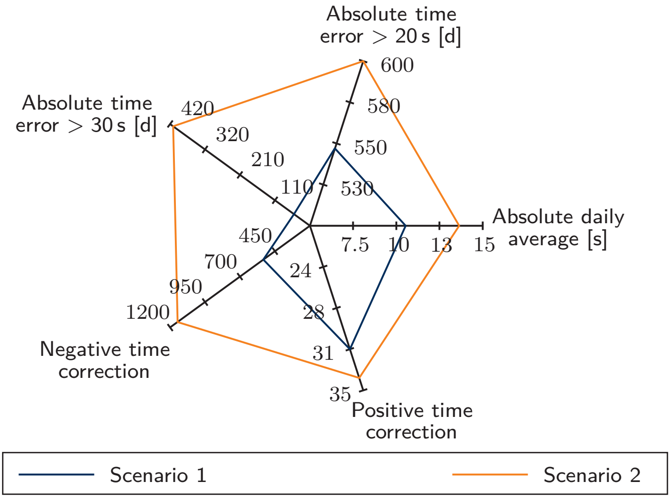


Figure 5.15.: Time control performance by end-2030.

is assumed that the system is in normal state, the transfer capacity available without limitation and the reserve dimensioning is done on a common basis (see Section 5.1).

The growing share of intermittent generation obviously causes an increasing need for active power reserves in Scenario 2: Figure 5.17 shows the weekly maximum and minimum of the load, wind power, and solar power forecast errors for 2015 as well as for 2030 summing up the total of all imbalances for all European countries. For the sake of clarity, forced unit outages are not plotted; the likelihood of their occurrence stays the same. In 2015, load is the predominant factor in the overall imbalance, and only a very minor seasonal pattern can be observed for wind and solar power forecast errors. In 2030, it is mainly wind and solar power that determine the overall imbalance. A seasonal pattern can be spotted for wind and solar power forecast errors. The latter has a remarkable impact in the summer season; sometimes it even transcends the load forecast error. Thus, load is changing from being the predominant influencing factor in the need for active power reserves to a minor but stable one. Note that this reaffirms the limitations of load-related dimensioning approaches.

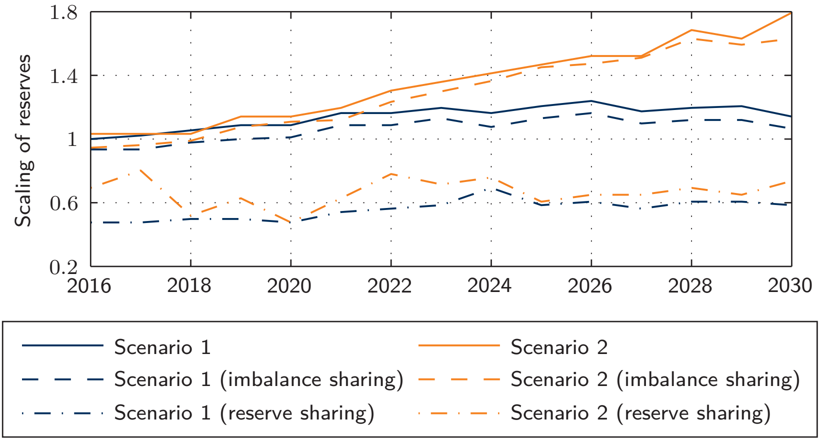


Figure 5.16.: Increasing reserve requirements for a constant hourly frequency standard deviation of 10 mHz; Scenario 1 in 2016 serves as a reference point (uni-directional transfer capacity assessment).

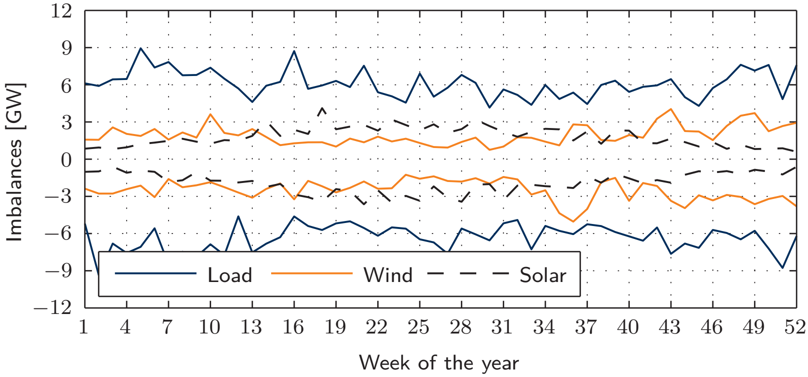
5.5. Challenges and Implementation Issues

The main objective of centralising frequency control in order to facilitate a single-area approach is to maximise synergy effects, and thus minimise the amount of active power reserves across the RGCE. However, consideration should be given to the fact that current system operation and the experience gained are based on decentralised frequency control.

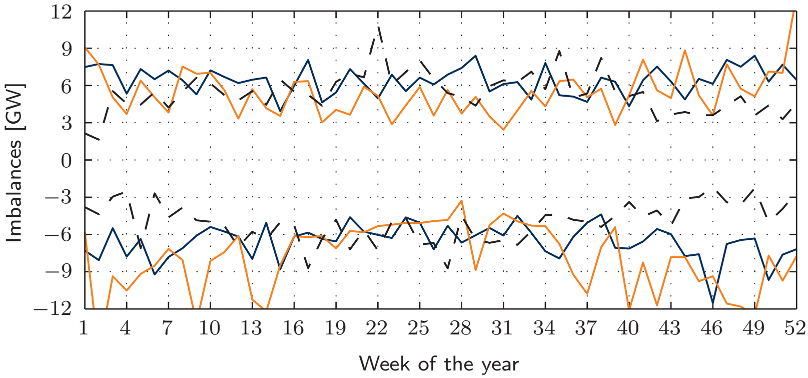
5.5.1. Changes in System Operation

Large-scale implementation of AGC coupling such as imbalance sharing or reserve sharing may give rise to implementation challenges:

Operational experience: The extensive operational experience gained so far is based on operational rules currently aligned to the classic load-frequency control structure described in Section 2.3.3. These rules will need to be aligned to a single-area control scheme in order to guarantee operational security, as a common control structure will add operational complexity to the system; subsequently, this requires gaining new operational experience to cope with normal operation as



(a) Maximum and minimum weekly imbalances in 2015.



(b) Maximum and minimum weekly imbalances in 2030 (same legend as in Figure 5.17a).

Figure 5.17.: Load, wind power and solar power forecast errors (Scenario B).

well as emergency situations that are the result of abnormal operation.

IT implementation: At present, procurement mechanisms, market designs, and system operation all vary across Europe and so do the IT solutions and software tools currently in use. A common reserve sharing approach calls for the alignment of software and uniformly defined data and communication interfaces. Both measures carry high costs.

Vulnerability: A centralisation of IT infrastructure and control technology carries the risk of increased susceptibility. Redundancy and fallback scenarios are crucial in preparing for natural disasters, terrorist threats, IT failures, and cyber-attacks.

In addition to the implementation challenges above, there are some other limitations arising from network topology which have not been tackled in this thesis, but must not be underestimated in order to ensure system security:

Congestion management: The process of determination and allocation of transmission capacity and reliability margins needs to be redefined in a common control setup for Continental Europe. Pertinent tools such as the day-ahead or intraday congestion forecast need to be updated, new operational patterns handled, and responsibilities assigned.

Network splitting: The chosen deficit probability guarantees having sufficient reserves most of the time: only few additional measures beyond market activity are necessary, for example, load or production shedding. This does not take into consideration a possible split of the network. In case of island operation, the geographical distribution of reserves is crucial.

5.5.2. Market Characteristics and Design

Regarding legal and political aspects, reference is made to the discussion and developments related to the topic of the "3rd energy package" (see Section 2.2.1). Imbalance sharing can generally be implemented without further harmonisation, as every TSO is free to choose its control loop parametrisation. In the case of European-wide reserve sharing, the political ambition to embark upon a common market model and a legal framework, which would allow the transnational exchange of ancillary services, are the prerequisites for realising a centralisation of frequency control in Europe. Apart from the above, the following issues need to be addressed regarding its practical implementation:

Framework agreement: The contractual and organisational framework regarding the procurement of active power reserves has to define rules which must be applicable to different kinds of providers in different countries in line with European legislation. An entity responsible for the co-ordination of the processes and contractual affairs may be set up, in a way similar to the setup of current so-called co-ordination centres, which are responsible for the European-wide matching of schedule notifications [43,107].

Pre-qualification requirements: The requirements concerning reserve delivery performance differ across Europe and so do the pre-qualification test procedures. For a pan-European reserve sharing process, the technical requirements and the procedures for testing them have to be defined and co-ordinated throughout the synchronous area to ensure equality for providers: Otherwise, reserve deliveries from two different countries will not be of the same quality. However, harmonised minimum requirements and standard products should not lower the established frequency quality by accepting the lowest performance of current providers for all providers.

Monitoring and ex post audit: For all providers and units, control mechanisms must be established at a comparable level by means of ex post audits and monitoring. The latter can be used in addition to ensure the secure real-time operation of the units and the power system.

This list is non-exhaustive. The aspects above are prerequisites for a non-discriminatory and non-hierarchical reserve sharing process. As mentioned before, they are not necessarily needed for a pan-European imbalance sharing process,but will support stepwise centralisation if already addressed at an early stage.

6. Closing Remarks

This chapter draws conclusions, discusses basic policy implications, and provides an outlook on possible future research.

6.1. Conclusion

Although European legislation, driven in particular by the vision of a pan-European market and a high share of intermittent generation, is pushing towards a consolidation of the European electricity sector, the supervision structure for system operation has been kept in its original form, where national system operators supervise their part of the system and manage frequency control locally. In this context, the main findings of this thesis are as follows:

- Historical frequency behaviour can be described well with the help of a simplified frequency control model. The imbalances TSOs need to compensate for in the scope of frequency control are not too dependent on country-specific market structures and ancillary service products. The main influencing factors can be described on a common basis.
- Current load-related and deterministic dimensioning methods are of limited use for future application. The need for active power reserves will increase in the coming years. As the crucial factor driving reserve dimensioning, load will be superseded by intermittent generation. However, the extrapolation of European scenarios showed some uncertainty concerning the future trend: A conservative scenario will not have a severe impact on the required amount, whereas a progressive scenario will quickly challenge the current decentralised AGC approach in the RGCE.
- The current frequency control setup can gradually be centralised. Imbalance and reserve sharing can be implemented between control

areas, which are operated under a decentralised load-frequency control structure, and congestions managed. Imbalance sharing does not require additional harmonisation of active power reserve processes and products. On the contrary, reserve sharing can only be managed on a non-discriminatory and fair basis if basic AGC properties, such as active power reserve dimensioning and activation rules, are harmonised in order to deliver comparable performance.

For the integration of sharing processes into the local AGC loops, virtual tie-lines are needed to enable communication between the TSOs. The optimisation logic can be implemented by multi-objective programming and is subject to linear constraints on its variables. The proposed approach is transparent from a regulatory point of view in order to grant model conformability and traceability.

- Concepts of AGC coupling can ensure an efficient and effective frequency quality in the European interconnected power system. A probabilistic dimensioning method, which takes into account relevant influencing factors, allows quantifying and evaluating the benefits of steps towards a centralised frequency control setup, as the required amount of active power reserves can be used as a criterion. The necessary amount of FRR and RR can be determined using current operational practices and generation portfolios as a baseline. The results indicate that current dimensioning recommendations are not always realised. Subsequently, the insights gained in this thesis may serve as a basis for further discussions on recent "green visions" and their operational challenges.

- Market-induced imbalances have a severe impact on frequency quality. The domination of hourly imbalance periods and respective hourly products impose a highly predictable frequency pattern. The effects of hourly market-induced imbalances can be anticipated and controlled with the help of manual reserves, whereas AGC resources are inadequate due to their slow and reactive control behaviour. Little effort is needed to practically implement a proactive activation pattern, and there is no need for additional reserves. This implies that TSOs and national regulatory authorities should properly consider the dependency between schedule-based operation and market activity in the drafting of upcoming regulations: Market-induced imbalances are the result of an inappropriate market design. An increasing share of market-induced imbalances will either jeopardise security of supply (no manual reserve activation) or lead to a vast increase in cost (more reserves needed). The latter can be seen as a vicious circle, as ancillary service providers are paid to compensate for a deterministic system-destabilising behaviour shown by producers.

- A reduction of the imbalance period can be beneficial for frequency control by reducing both total energy and the impact of market-induced imbalances. For shorter imbalance periods, the current RR products will not be an adequate means and they will eventually become obsolete. Manual reserves with a minimum duration time close to the imbalance period lose their operational flexibility.

- The choice of a common ramping period is crucial for the functioning of AGC. Today, frequency control fundamentals and energy balancing incentives in the RGCE are not well-aligned. Because of ramping constraints, market-related schedule notifications cannot be used as a direct reference for the calculation of imbalance energy; instead, energy correction on the basis of ramping should be considered. This becomes more important as the imbalance period gets shorter. In general, the design of the market should be adjusted as the imbalance period changes. Quarter-hourly products only hold a minor share in current wholesale market activity, as hourly day-ahead markets prevail over short-term trading.

- Time control as a common control process, whose raison d'être has been called into question in recent years, will gain in importance, especially if active power reserves are not increased accordingly. If this is so, there will be a shift from nationally compensating for imbalances in real-time to retrospectively averaging frequency deviations by means of time control, which would imply a change in the European frequency control policy. In simple terms, the granularity of the adherence to the nominal frequency will diminish.

- For any practical implementations of sharing processes, local imbalances need to be properly determined. The analysis of current and past frequency control regulations of the RGCE identified possibilities for improving the sizing of the bias factor in order to align it more closely to the system's actual frequency characteristic. Best performance is achieved by non-linear methods. These more complicated methods reflect the underlying properties of the system more accurately. The methods outlined in this thesis can be used as a basis for an in-depth investigation into the differences between the methods proposed. Without further studies based on a more detailed assessment of data available to the different TSOs, it does not seem prudent to suggest a final choice regarding the method which could replace the current one. To apply the benchmarking simulation model, points in time when the system's frequency-response characteristic is known must be found. It is up to future work to find new ways of measuring the systems actual frequency-response characteristic so that new sizing algorithms can successfully be compared and implemented using the available tools.

6.2. Outlook

In the future, TSOs must reach a decision on the trade-off between operational sovereignty and cost efficiency. Currently, operational responsibilities are assigned to national TSOs and their respective national regulatory authorities (for example, operational security and planning, ancillary services). Consolidating existing control areas is an obvious technical solution for lowering the increasing demand for active power reserves, since a centralised approach will lead to a reduction of reserves and ancillary service procurement costs. Despite these obvious advantages, the difficulty of implementing such an international distribution of operational responsibilities should not be underestimated. A common understanding of operational matters will have to be developed, contracts will have to be written, rules defined, and processes adjusted. In particular, aspects related to network topology (for example, congestion management, distribution of reserves) will require careful attention.

To implement sharing concepts on a large scale, technical, organisational, and financial details need to be agreed upon by TSOs and their respective national regulatory authorities. The energy exchange due to imbalance sharing has so far been treated similar to the inadvertent energy exchange between areas ("unintentional deviations"). In the future, a financial model could be established that would allow real-time pricing of imbalance exchanges within the framework of sharing processes. These issues have to be tackled in future work.

The European legal framework currently being developed around the proposed Framework Guidelines and Network Codes will support these propositions. This fact is underlined by concepts such as standard products and common merit order lists. In this context, intermittent generation providers should be incentivised to gain operational flexibility or, at the least, precedence should be limited in order to bound respective forecast errors.

Furthermore, the legal framework will have to find a balance between market-related and operational requirements. Sharing processes allow a reduction of ancillary service resources, but a fixed capacity allocation for this purpose is not being considered. Future efforts should also focus on the interaction between day-ahead and intraday congestion forecasting on the one hand and real-time use of transfer capacity for frequency control purposes on the other. For practical implementation, there are various possibilities to assess transfer capacities and determine the underlying distribution rule. The choice of the amount of transfer capacity between countries that is allowed to be used for sharing processes mostly determines the extent to which the TSOs can benefit from AGC coupling. The choice of the distribution rule should depend on the frequency control and balancing performance indicators used in the areas and on the national imbalance energy pricing for avoiding distorted incentives for advertent imbalances.

In this thesis, all considerations and coupling concepts assumed normal operation. Both states of alert (for example, local disturbances, persisting frequency deviations above the standard frequency range) and states of emergency (for example, partial blackouts, frequency deviations above the ancillary service range) were not discussed. While AGC coupling can increase security of supply and reduce costs in normal operation, it may also reduce the amount of local reserves available in case of system disturbances adversely affecting system security and stability. This can be counteracted, for example, by extended TSO intervention in power plant operation in case of an alert or a state of emergency or by similar non-market procedures.

Future work should also focus on the practical alignment of the order of the different markets. Today, day-ahead markets are operated on an hourly basis, and it is only the continuous trading carried out on intraday markets that is sometimes done on a quarter-hourly basis, i.e. with quarter-hourly products. To motivate BRPs to manage their portfolio at the resolution of the imbalance period, all standard products should have the same duration.

If this is combined with a reduction and harmonisation of the imbalance period, markets can be merged to avoid a decline in market liquidity.

7. References

[1] F. Abbaspourtorbati, M. Scherer, A. Ulbig, and G. Andersson. **Towards an Optimal Activation Pattern of Tertiary Control Reserves in the Power System of Switzerland**. In *American Control Conference (ACC)*, pages 3629–3636, June 2012.

[2] ACER. **Framework Guidelines on Electricity Balancing (FG-2012-E-009)**, September 2012.

[3] ADMIE S.A. **Methodology for the Evaluation of the NTC Values at the Greek Interconnections**, 2010.

[4] J. Albrecht and R. Laleman. **Policy Trade-Offs for the Belgian Electricity System**. Technical report, Universiteit Gent, September 2014.

[5] G. Andersson. **Dynamics and Control of Electric Power Systems (Lecture 227-0528-00)**. Technical report, ETH Zurich, February 2011.

[6] G. Andersson and M. Höckel. **Second Opinion zur "Bestimmung des Bedarfes an Regelreserve für die Regelzone Schweiz"**. Technical report, ETH Zurich, Bern University of Applied Sciences, September 2008.

[7] H. P. Asal, P. Barth, E. Grebe, and D. Quadflieg. **Dynamic System Studies of New Requirements and Strategies for the Primary Control in the UCPTE/CENTREL Power System**. In *Cigré 1998 Session*, 39-106, 1998.

[8] A. Baranzini, S. Weber, M. Bareit, and N. A. Mathys. **The Causal Relationship Between Energy Use and Economic Growth in Switzerland**. *Energy Economics*, 36:464–470, 2013. ISSN 0140-9883.

[9] J. Büchner, T. Türkucar, W. Nick, F.-R. Graf, E. Handschin, W. Horenkamp, D. König, D. Waniek, and W. Schulz. **Gutachten "Bestimmung des regelzoneninternen Regelleistungsbedarfs für Sekundärregelung und Minutenreserve"**. Technical report, E-Bridge Consulting GmbH, TU Dortmund University, September 2006.

[10] M. Beck. **Netzregelung in der Schweiz – Von sieben zu einer Regelzone mit grenzüberschreitender Leistungsvorhaltung**. In *10. ETG/GMM-Fachtagung – Die Dynamik des Netzes*, March 2011.

[11] F. E. Beichelt and L. P. Fatti. **Stochastic Processes and Their Applications**. CRC Press, 2001.

[12] R. Billinton and W. Li. **Reliability Assessment of Electric Power Systems Using Monte Carlo Methods**. Plenum Press, New York, 1st edition, 1994.

[13] H. Bludszuweit, J. Dominguez-Navarro, and A. Llombart. **Statistical Analysis of Wind Power Forecast Error**. *IEEE Transactions on Power Systems*, 23(3):983–991, August 2008. ISSN 0885-8950.

[14] W. Bönte, S. Nielen, N. Valitov, and T. Engelmeyer. **Price Elasticity of Demand in the EPEX Spot Market for Electricity – New Empirical Evidence**. *Economics Letters*, 135:5–8, 2015. ISSN 0165-1765.

[15] J. C. G. Boot, W. Feibes, and J. H. C. Lisman. **Further Methods of Derivation of Quarterly Figures from Annual Data**. *Journal of the Royal Statistical Society – Series C (Applied Statistics)*, 16 (1):65–75, 1967. ISSN 00359254, 14679876.

[16] S. Boyd and L. Vandenberghe. **Convex Optimization**. Cambridge University Press, 2009.

[17] O. Brückl. **Wahrscheinlichkeitstheoretische Bestimmung des Regel- und Reserveleistungsbedarfs in der Elektrizitätswirtschaft**. PhD thesis, Technische Universität München, 2006.

[18] K. Bruninx, D. Madzharov, E. Delarue, and W. D'haeseleer. **Impact of the German Nuclear Phase-Out on Europe's Electricity**

Generation. In *9th International Conference on the European Energy Market (EEM)*, pages 1–10, May 2012.

[19] C. Bucher. **Analysis and Simulation of Distribution Grids with Photovoltaics**. PhD thesis, ETH Zurich, 2014.

[20] M. Bucksteeg, L. Niesen, P. Himmes, D. Schober, C. Weber, B. Baumgart, T. Plöger, D. Willemsen, D. Nailis, L. Schuffelen, and M. Bittner. **Marktdesign für zukunftsfähige Elektrizitätsmärkte unter besonderer Berücksichtigung der vermehrten Einspeisung von erneuerbaren Energien (DESIRE)**. Technical report, Universität Duisburg-Essen, Trianel GmbH, BET Büro für Energiewirtschaft und technische Planung GmbH, September 2014.

[21] Bundesministerium der Justiz (BMJ). **Verordnung über den Zugang zu Elektrizitätsversorgungsnetzen (Stromnetzzugangsverordnung – StromNZV)**. In *Bundesgesetzblatt*, volume 1, pages 2185–2264, July 2005.

[22] A. Burger, M. Scherer, M. Buser, and P. Wenk. **Kooperationsszenarien für Bahnstrom- und Landesversorgungsnetz – Eine Analyse des technischen Potenzials**. *Bulletin SEV/VSE*, 12: 12–15, 2012.

[23] B. Burstedde. **From Nodal to Zonal Pricing: A Bottom-Up Approach to the Second-Best**. In *European Energy Market (EEM), 2012 9th International Conference on the*, pages 1–8, May 2012.

[24] P. D. Cameron. **Competition in Energy Markets – Law and Regulation in the European Union**. Oxford University Press, 2nd edition, 2007.

[25] J. Campillo, F. Wallin, I. Vassileva, and E. Dahlquist. **Electricity Demand Impact from Increased Use of Ground Sourced Heat Pumps**. In *2012 3rd IEEE PES International Conference and Exhibition on Innovative Smart Grid Technologies (ISGT Europe)*, pages 1–7, 2012.

[26] ČEPS, Elia System Operator S.A., Energinet.dk, Swissgrid Ltd., TenneT TSO B.V., and Tennet TSO GmbH. **Comparison of System Balancing Management for Six Electricity Transmission System**

Operators. Technical report, GEN and E-Bridge Consulting GmbH, September 2013.

[27] W. Christiaanse. **Short-Term Load Forecasting Using General Exponential Smoothing**. *IEEE Transactions on Power Apparatus and Systems*, PAS-90(2):900–911, March 1971. ISSN 0018-9510.

[28] A. Ciarreta and A. Zarraga. **Economic Growth and Electricity Consumption in 12 European Countries: A Causality Analysis Using Panel Data**. In *6th International Conference on the European Energy Market (EEM)*, pages 1–8, 2009.

[29] J. Cimadevila García, F. Heus, E. M. Kurscheid, A. Mondovic, K. Rubiolo, and M. Scherer. **Technical Benefits of Quarter-Hourly Products to Reduce Deterministic Frequency Deviations**. Technical report, ENTSO-E, April 2014.

[30] Consentec GmbH. **Gutachten zur Dimensionierung des Regelleistungsbedarfs unter dem NRV**. Technical report, Consentec GmbH, December 2010.

[31] E. Cuthill and J. McKee. **Reducing the Bandwidth of Sparse Symmetric Matrices**. In *24th ACM National Conference*, pages 157–172, 1969.

[32] G. Dany. **Kraftwerksreserve in elektrischen Verbundsystemen mit hohem Windenergieanteil**. PhD thesis, RWTH Aachen University, 2000.

[33] G. Dany. **Power Reserve in Interconnected Systems with High Wind Power Production**. In *IEEE PowerTech Porto*, volume 4, pages 1–6, 2001.

[34] M. Davies, A. Kölz, M. Kuhn, D. Monkhouse, and J. Strauss. **Latest Control and Protection Innovations Applied to the Basslink HVDC Interconnector**. In *The 8th IEE International Conference on AC and DC Power Transmission (ACDC 2006)*, pages 30–35, March 2006.

[35] M. de la Torre Rodríguez, M. Scherer, D. Whitley, and F. Reyer. **Frequency Containment Reserves Dimensioning and Target Performance in the European Power System**. In *2014 IEEE PES General Meeting — Conference Exposition*, pages 1–5, July 2014.

[36] P. Díaz Redondo and O. van Vliet. **Modelling the Energy Future of Switzerland After the Phase out of Nuclear Power Plants**. *Energy Procedia*, 76:49–58, 2015. ISSN 1876-6102.

[37] B. Dieckmann. **Engpassmanagement im Europäischen Strommarkt**. PhD thesis, Westfälische Wilhelms-Universität Münster, 2008.

[38] R. Doherty and M. O'Malley. **A New Approach to Quantify Reserve Demand in Systems with Significant Installed Wind Capacity**. *IEEE Transactions on Power Systems*, 20(2):587–595, May 2005. ISSN 0885-8950.

[39] K. W. Edwin et al. **Zuverlässigkeitsberechnung elektrischer Energieversorgungssysteme**. Technical report, RWTH Aachen University, 1986.

[40] M. Ehrgott. **Multicriteria Optimization**. Springer-Verlag Berlin Heidelberg, 2nd edition, 2005.

[41] C. Elberg, C. Growitsch, F. Höffler, J. Richter, and A. Wambach. **Untersuchungen zu einem zukunftsfähigen Strommarktdesign**. Technical report, Energiewirtschaftliches Institut an der Universität zu Köln (EWI), March 2012.

[42] ENTSO-E. **Statistical Yearbook 2009**, November 2010. URL www.entsoe.eu.

[43] ENTSO-E. **The ENTSO-E Scheduling System (ESS) Implementation Guide**, November 2012. URL www.entsoe.eu.

[44] ENTSO-E. **Network Code on Capacity Allocation and Congestion Management**, September 2012. URL www.entsoe.eu.

[45] ENTSO-E. **Statistical Yearbook 2011**, November 2012. URL www.entsoe.eu.

[46] ENTSO-E. **Scenario Outlook and Adequacy Forecast 2013-2030**, April 2013. URL www.entsoe.eu.

[47] ENTSO-E. **Network Code on Load-Frequency Control and Reserves**, June 2013. URL www.entsoe.eu.

[48] ENTSO-E. **Scenario Outlook and Adequacy Forecast 2014-2030**, October 2014. URL www.entsoe.eu.

[49] ENTSO-E. **Network Code on Electricity Balancing**, Version 3.0, August 2014. URL www.entsoe.eu.

[50] ENTSO-E. **Statistical Factsheet 2014**, April 2015. URL www.entsoe.eu.

[51] ENTSO-E. **Scenario Outlook and Adequacy Forecast 2015**, June 2015. URL www.entsoe.eu.

[52] ENTSO-E. **Statistical Database**, Website accessed on 11 November 2014. URL www.entsoe.eu.

[53] ENTSO-E. **ENTSO-E Member Companies**, Website accessed on 16 January 2014. URL www.entsoe.eu.

[54] EPEX SPOT SE. **2012 Volumes on European Power Exchange EPEX SPOT Hit New Record**, January 2013.

[55] EPEX SPOT SE. **EPEX SPOT Operational Rules**. In *EPEX SPOT Market Rules and Regulation*, December 2015.

[56] EPEX SPOT SE. **2014 Power Trading Volumes Grow by 10.4 %**, January 2015.

[57] ETSO. **Procedures for Cross-Border Transmission Capacity Assessments**, October 2001.

[58] European Climate Foundation (ECF). **A Practical Guide to a Prosperous, Low-Carbon Europe**. Technical Report 1, Roadmap 2050, April 2010. URL www.roadmap2050.eu.

[59] European Commission. **Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 Concerning Common Rules for the Internal Market in Electricity**. *Official Journal of the European Union*, 40(L27):20–29, January 1997. ISSN 0378-6978.

[60] European Commission. **Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 Concerning Common Rules for the Internal Market in Electricity and Repealing Directive 96/92/EC**. *Official Journal of the European Union*, 46(L176):37–55, July 2003. ISSN 1725-2555.

[61] European Commission. **Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC**. *Official Journal of the European Union*, 52(L140): 16–32, June 2009. ISSN 1725-2555.

[62] European Commission. **Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on Conditions for Access to the Network for Cross-Border Exchanges in Electricity and Repealing Regulation (EC) No 1228/2003**. *Official Journal of the European Union*, 52(L211):15–35, August 2009. ISSN 1725-2555.

[63] European Commission. **Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 Establishing an Agency for the Cooperation of Energy Regulators**. *Official Journal of the European Union*, 52(L211):1–14, August 2009. ISSN 1725-2555.

[64] J. Fajardo and A. Farias. **Generalized Hyperbolic Distributions and Brazilian Data**. *Brazilian Review of Econometrics*, 24(2):249–271, November 2004.

[65] B. Flechner. **Die notwendige Modellierungsgenauigkeit bei der Energieeinsatzplanung in hydrothermischen Kraftwerkssystemen**. PhD thesis, RWTH Aachen University, 1995.

[66] K. Flinkerbusch and M. Heuterkes. **Cost Reduction Potentials in the German Market for Balancing Power**. *Energy Policy*, 38(8): 4712–4718, 2010. ISSN 0301-4215.

[67] J. Frunt, W. Kling, R. Hermans, F. Nobel, and W. de Boer. **Impact of Design Variables on Balancing Markets**. In *7th International Conference on the European Energy Market (EEM)*, pages 1–6, June 2010.

[68] M. D. Galus. **Agent-Based Modeling and Simulation of Large Scale Electric Mobility in Power Systems**. PhD thesis, ETH Zurich, 2012.

[69] W. Glaunsinger, R. Heueck, E. Welfonder, and B. Hall. **Study of the Dependence of Consumer Subsystems on Frequency and Voltage**. In *Cigré 1994 Session*, 39/11-04, 1994.

[70] Global Wind Energy Council (GWEC). **Global statistics**. Website accessed on 25 June 2013. URL www.gwec.net.

[71] G. Gross and F. Galiana. **Short-Term Load Forecasting**. *Proceedings of the IEEE*, 75(12):1558–1573, December 1987. ISSN 0018-9219.

[72] M. Haller, M. Scherer, and B. Geissler. **Erfahrungen im deutschen Netzregelverbund – Eine erste Bilanz nach einem Jahr operativen Betriebs**. *Bulletin SEV/VSE*, 8:17–19, August 2013.

[73] J. Han and A. Papavasiliou. **Congestion Management Through Topological Corrections: A Case Study of Central Western Europe**. *Energy Policy*, 86:470–482, 2015. ISSN 0301-4215.

[74] E. Handschin, U. Häger, W. Horenkamp, W. Schulz, and D. Waniek. **Abschätzung der EEG-bedingten Kosten aus Sicht eines Übertragungsnetzbetreibers**. *ew – Magazin für die Energiewirtschaft*, 106(5):22–30, 2007.

[75] E. Handschin, C. Rehtanz, W. Horenkamp, J. Schwippe, and D. Waniek. **Ermittlung des Regelleistungsbedarfs der Regelzone Schweiz ab 01.01.2009**. Technical report, TU Dortmund University, December 2008.

[76] N. Hatziargyriou and A. Zervos. **Wind Power Development in Europe**. *Proceedings of the IEEE*, 89(12):1765–1782, 2001. ISSN 0018-9219.

[77] H.-J. Haubrich and Consentec GmbH. **Gutachten zur Höhe des Regelenergiebedarfs**. Technical report, Consentec GmbH, December 2008.

[78] Hauptabteilung für die Sicherheit der Kernanlagen (HSK). **Aufsichtsbericht 2005 über die nukleare Sicherheit in den schweizerischen Kernanlagen**. Technical report, HSK-AN-5800, 2005.

[79] M. Hübler and A. Löschel. **The EU Decarbonisation Roadmap 2050 – What way to walk?** *Energy Policy*, 55:190–207, 2013. ISSN 0301-4215.

[80] E. Hirst and B. Kirby. **Defining Intra- and Interhour Load Swings**. *IEEE Transactions on Power Systems*, 13(4):1379–1385, November 1998. ISSN 0885-8950.

[81] E. Hirst and B. Kirby. **Electric-Power Ancillary Services**. Technical report, Oak Ridge National Laboratory, February 1996.

[82] J. Hobohm. **More Natural Gas for Climate Protection?** Technical report, Stiftung Wissenschaft und Politik (SWP), January 2009. URL www.swp-berlin.org.

[83] B.-M. Hodge, D. Lew, M. Milligan, H. Holttinen, S. Sillanpää, E. Gómez-Lázaro, R. Scharff, L. Söder, X. Larsén, G. Giebel, D. Flynn, and J. Dobschinski. **Wind Power Forecasting Error Distributions: An International Comparison**. In *The 11th Annual International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants*, November 2012.

[84] S. Hunt. **Making Competition Work in Electricity**. Wiley Finance Editions Series. John Wiley & Sons, Inc., New York, 1st edition, March 2002.

[85] N. Jaleeli, L. S. VanSlyck, D. Ewart, L. Fink, and A. Hoffmann. **Understanding Automatic Generation Control**. *IEEE Transactions on Power Systems*, 7(3):1106–1122, August 1992. ISSN 0885-8950.

[86] P. L. Joskow. **Introducing Competition into Regulated Network Industries: From Hierarchies to Markets in Electricity**. *Industrial and Corporate Change*, 2(5):341–382, 1996.

[87] J. L. Jurewitz. **California's Electricity Debacle: A Guided Tour**. *The Electricity Journal*, 15(4):10–29, 2002. ISSN 1040-6190.

[88] B. Kirby and E. Hirst. **Unbundling Electricity: Ancillary Services**. *IEEE Power Engineering Review*, 16(6):5–6, June 1996. ISSN 0272-1724.

[89] B. Kirby, E. Hirst, and J. Vancoevering. **Identification and Definition of Unbundled Electric Generation and Transmission Services**. Technical report, Oak Ridge National Laboratory, 1995.

[90] S. Krahl, C. Maurer, and T. Tarnowski. **Bestimmung des Bedarfs an Regelreserve für die Regelzone Schweiz**. In *Jahresbericht 2008 der Forschungsgesellschaft Energie an der RWTH Aachen e. V.*, June 2008.

[91] P. Kundur. **Power System Stability and Control**. McGraw-Hill, Inc., 1994.

[92] I. Kuzle, D. Bosnjak, and S. Tesnjak. **An Overview of Ancillary Services in an Open Market Environment**. In *Mediterranean Conference on Control Automation (MED)*, pages 1–6, June 2007.

[93] M. Lambert and D. Imbert. **Proposition de Dimensionnement de la Reserve Secondaire du Réglage Fréquence Puissance**. Technical report, Électricité de France SA (EDF), July 1991.

[94] Y. V. Makarov, P. V. Etingov, N. Zhou, J. Ma, N. A. Samaan, R. Diao, S. V. Malhara, R. T. Guttromson, P. Du, and C. Sastry. **Analysis Methodology for Balancing Authority Cooperation in High Penetration of Variable Generation**. Technical report, Pacific Northwest National Laboratory (PNNL), February 2010.

[95] Y. V. Makarov, S. Lu, N. Samaan, Z. Huang, K. Subbarao, P. V. Etingov, J. Ma, R. P. Hafen, R. Diao, and N. Lu. **Integration of Uncertainty Information into Power System Operations**. In *IEEE Power and Energy Society General Meeting*, pages 1–13, July 2011.

[96] Y. Makarov, C. Loutan, J. Ma, and P. de Mello. **Operational Impacts of Wind Generation on California Power Systems**. *Power Systems, IEEE Transactions on*, 24(2):1039–1050, May 2009. ISSN 0885-8950.

[97] C. Maurer, S. Krahl, and H. Weber. **Dimensioning of Secondary and Tertiary Control Reserve by Probabilistic Methods**. *European Transactions on Electrical Power*, 19:544–552, January 2009.

[98] K. M. Miettinen. **Nonlinear Multiobjective Optimization**. Springer Science+Business Media, 1st edition, 1998.

[99] C. Monteiro, R. Bessa, V. Miranda, A. Botterud, J. Wang, and G. Conzelmann. **Wind Power Forecasting: State-of-the-Art 2009**. Technical Report ANL/DIS-10-1, Argonne National Laboratory, November 2009.

[100] G. Neidhöfer. **50-Hz Frequency – How the Standard Emerged from a European Jumble**. *IEEE Power and Energy Magazine*, 9 (4):66–81, 2011. ISSN 1540-7977.

[101] K. Neuhoff, J. Barquin, J. W. Bialek, R. Boyd, C. J. Dent, F. Echavarren, T. Grau, C. von Hirschhausen, B. F. Hobbs, F. Kunz, C. Nabe, G. Papaefthymiou, C. Weber, and H. Weigt. **Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity**. *Energy Economics*, 40:760–772, 2013. ISSN 0140-9883.

[102] Nordel. **AGREEMENT (Translation) Regarding Operation of the Interconnected Nordic Power System (System Operation Agreement)**, December 2008. URL www.entsoe.eu.

[103] A. R. Oneal. **A Simple Method for Improving Control Area Performance: Area Control Error (ACE) Diversity Interchange ADI**. *IEEE Transactions on Power Systems*, 10(2):1071–1076, May 1995. ISSN 0885-8950.

[104] OpHB-Team. **Appendix 1: Load-Frequency Control and Performance**. In *UCTE Operation Handbook*, Version 1.9, June 2004.

[105] OpHB-Team. **Policy 1: Load-Frequency Control and Performance**. In *UCTE Operation Handbook*. ENTSO-E, Version 2.2, July 2004.

[106] OpHB-Team. **Policy 1: Load-Frequency Control and Performance**. In *UCTE Operation Handbook*. ENTSO-E, Version 3.0, March 2009.

[107] OpHB-Team. **Appendix 2: Scheduling and Accounting**. In *UCTE Operation Handbook*, June 2009.

[108] OpHB-Team. **Policy 5: Emergency Operations**. In *UCTE Operation Handbook*. ENTSO-E, Version 3.0, August 2010.

[109] OpHB-Team. **Policy 4: Co-Ordinated Operational Planning**. In *UCTE Operation Handbook*. ENTSO-E, Version 2.7, December 2014.

[110] Parlamentsdienste. **Bundesversammlung 50. Legislatur – Ausblick**, October 2015.

[111] B. K. Parsons, Y.-h. Wan, and B. Kirby. **Wind Farm Power Fluctuations, Ancillary Services and System Operating Impact Analysis Activities in the United States**. Technical report, National Renewable Energy Laboratory (NREL), Oak Ridge National Laboratory (ORNL), July 2001. URL www.nrel.gov.

[112] K. Prause. **The Generalized Hyperbolic Model: Estimation, Financial Derivatives, and Risk Measures**. PhD thesis, Albert-Ludwigs-Universität Freiburg i. Br., 1999.

[113] PricewaterhouseCoopers LLP (PwC), Potsdam Institute for Climate Impact Research (PIK), International Institute for Applied Systems Analysis (IIASA), and European Climate Forum (ECF). **100 % Renewable Electricity – A Roadmap to 2050 for Europe and North Africa**. Technical report, PricewaterhouseCoopers LLP (PwC), March 2010. URL www.supersmartgrid.net.

[114] Y. G. Rebours, D. S. Kirschen, M. Trotignon, and S. Rossignol. **A Survey of Frequency and Voltage Control Ancillary Services – Part I: Technical Features**. *IEEE Transactions on Power Systems*, 22(1):350–357, February 2007a. ISSN 0885-8950.

[115] Y. G. Rebours, D. S. Kirschen, M. Trotignon, and S. Rossignol. **A Survey of Frequency and Voltage Control Ancillary Services – Part II: Economic Features**. *IEEE Transactions on Power Systems*, 22(1):358–366, February 2007b. ISSN 0885-8950.

[116] M. Roggenbau. **Kooperation der Übertragungsnetzbetreiber zur Minutenreservehaltung in elektrischen Verbundsystemen**. PhD thesis, RWTH Aachen University, 1999.

[117] P. Schavemaker and R. Beune. **Flow-Based Market Coupling and Bidding Zone Delimitation: Key Ingredients for an Efficient Capacity Allocation in a Zonal System**. In *10th International Conference on the European Energy Market (EEM)*, pages 1–6, May 2013.

[118] P. Schavemaker, M. Aguado, R. Bourgeois, J. Bourmaud, M. Ceratto, M. Jäkel, C. Mestdag, M. Pool, M. Rohleder, S. Scolari, W. Van Den Reek, J. Van Casteren, O. Weiss, and J. Wolpert. **Flow-Based Market Coupling in the Central Western European Region – on the Eve of Implementation**. In *Cigré 2012 Session*, C5-204, 2012.

[119] M. Scherer. **Frequenzschwankungen durch nicht konforme Fahrplanwechsel – Ein verbundweites Problem und die Schweizer Lösung**. *Bulletin SEV/VSE*, 3:16–19, March 2011.

[120] M. Scherer. **Fahrpläne müssen eingehalten werden**. *ENERGY.NOW!*, 4:18–19, August 2011.

[121] M. Scherer. **Richtige Regelreservedimensionierung – Validierung und kontinuierliche Anpassung**. *ew – Magazin für die Energiewirtschaft*, 110(24):62–65, November 2011.

[122] M. Scherer. **Anreizbasierte Berechnung der Ausgleichsenergie – Verbesserung der Frequenzstabilität**. *ew – Magazin für die Energiewirtschaft*, 110(12):32–35, May 2011.

[123] M. Scherer and G. Andersson. **How Future-Proof Is the Continental European Frequency Control Structure?** In *IEEE PowerTech Eindhoven*, pages 1–6, June 2015.

[124] M. Scherer and G. Andersson. **A Blueprint for the European Imbalance Netting Process Using Multi-Objective Optimization**. In *IEEE Energycon 2016*, pages 1–6, April 2016.

[125] M. Scherer and B. Geissler. **Das Konzept Netzregelverbund – Hintergründe der Kooperation von Übertragungsnetzbetreibern**. *Bulletin SEV/VSE*, 5:27–29, May 2012.

[126] M. Scherer and P. Zolotarev. **Frequency-Response Coupling Between Synchronous Areas in Europe**. In *IEEE PowerTech Eindhoven*, pages 1–6, June 2015.

[127] M. Scherer, D. Schlipf, and W. Sattinger. **Test for Primary Control Capability**. Technical report, Version 1.1, April 2011.

[128] M. Scherer, M. Zima, and G. Andersson. **An Integrated Pan-European Ancillary Services Market for Frequency Control**. *Energy Policy*, 62:292–300, 2013. ISSN 0301-4215.

[129] M. Scherer, O. Haubensak, and T. Staake. **Assessing Distorted Trading Incentives of Balance Responsible Parties Based on the Example of the Swiss Power System**. *Energy Policy*, 86: 792–801, 2015. ISSN 0301-4215.

[130] M. Scherer, E. Iggland, A. Ritter, and G. Andersson. **Improved Frequency Bias Factor Sizing for Non-Interactive Control**. In *Cigré 2012 Session*, C2-113, 2012.

[131] D. Schlipf, M. Scherer, and M. Haller. **Test for Secondary Control Capability**. Technical report, Version 2.1, April 2013. URL www.swissgrid.ch.

[132] W. Schulz. **Strategien zur effizienten Integration der Windenergie in den deutschen Elektrizitätsmarkt**. PhD thesis, TU Dortmund University, September 2007.

[133] Schweizerische Eidgenossenschaft. **Die im StromVG stipulierte Reservehaltung – Bericht des Bundesrates in Beantwortung des Postulates 08.3757 der UREK-N vom 10. November 2008**, June 2009.

[134] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R. E. Bohn. **Spot Pricing of Electricity**. Springer Science+Business Media, 2013.

[135] L. Söder. **Reserve Margin Planning in a Wind-Hydro-Thermal Power System**. *IEEE Transactions on Power Systems*, 8(2):564–571, May 1993. ISSN 0885-8950.

[136] H. Singh and A. Papalexopoulos. **Competitive Procurement of Ancillary Services by an Independent System Operator**. *Power Systems, IEEE Transactions on*, 14(2):498 –504, May 1999. ISSN 0885-8950.

[137] J. Stoffel. **Hierarchische Netzregelung**. PhD thesis, ETH Zurich, 1983.

[138] S. Stoft. **Power System Economics: Designing Markets for Electricity**. John Wiley & Sons, Inc., New York, 1st edition, 2002.

[139] Swissgrid Ltd. **Annual Report 2009**, May 2010.

[140] Swissgrid Ltd. **Balance Group Model (BGM) Introduction**. Technical report, Version 1.3, December 2012. URL www.swissgrid.ch.

[141] Swissgrid Ltd. **Netzdaten 2012 – Daten und Fakten zum Schweizer Stromübertragungsnetz**, May 2013.

[142] Swissgrid Ltd. **General Balance Group Regulations – General Regulations Relating to the Balance Group Contract**. Version 1.8, September 2015.

[143] Swissgrid Ltd. and Verband Schweizerischer Elektrizitätsunternehmen (VSE). **Transmission Code 2013**. Branchenempfehlung Strommarkt Schweiz, December 2013.

[144] TenneT TSO GmbH. **Determination of Transfer Capacity at Trade Relevant Cross-Border Interconnections of TenneT TSO GmbH**, July 2012.

[145] T. Traber and C. Kemfert. **German Nuclear Phase-Out Policy: Effects on European Electricity Wholesale Prices, Emission Prices, Conventional Power Plant Investments and Electricity**

Trade. Technical report, Deutsches Institut für Wirtschaftsforschung (DIW), 2012. URL www.diw.de.

[146] K. Trautmann. **Wahrscheinlichkeitstheoretische Modelle zur Bestimmung der Verfügbarkeit von Kraftwerksanlagen**. *Elektrizitätswirtschaft*, 73(1):3–8, 1974.

[147] UCPTE. **Rapport Annuel 1957-1958**. Heidelberg, Germany, 1958.

[148] UCPTE. **Rapport Annuel 1958-1959**. Heidelberg, Germany, 1959.

[149] UCPTE. **Rapport Annuel 1981-1982**. Rhode-St. Genèse, Belgium, November 1982.

[150] U.S. Energy Information Administration (EIA). **International Energy Statistics**. Website accessed on 21 May 2013. URL www.eia.gov.

[151] R. van der Veen and R. Hakvoort. **Balance Responsibility and Imbalance Settlement in Northern Europe – An Evaluation**. In *6th International Conference on the European Energy Market (EEM)*, pages 1–6, May 2009.

[152] Verband Schweizerischer Elektrizitätsunternehmen (VSE). **Anbindung von Regelpools an den Schweizer SDL-Markt**. Branchenempfehlung Strommarkt Schweiz, October 2013.

[153] Verband Schweizerischer Elektrizitätsunternehmen (VSE). **Netznutzungsmodell für das Schweizerische Verteilnetz – Grundlagen zur Netznutzung und Netznutzungsentschädigung in den Verteilnetzen der Schweiz**. Branchenempfehlung Strommarkt Schweiz, July 2014.

[154] Verband Schweizerischer Elektrizitätsunternehmen (VSE). **Standardisierter Datenaustausch für den Strommarkt Schweiz – Umsetzungsdokument für die standardisierten Datenaustauschprozesse im Strommarkt Schweiz**. Branchenempfehlung Strommarkt Schweiz, December 2014.

[155] M. Vogel, U. Ziegler, T. Hauri, M. Scherer, H. Feger, and M. Beck. **BGM User Group Meeting**. Swissgrid Ltd., November 2010.

[156] K. R. Voorspools and W. D. D'haeseleer. **Are Deterministic Methods Suitable for Short Term Reserve Planning?** *Energy Conversion and Management*, 46(13-14):2042–2052, 2005. ISSN 0196-8904.

[157] P. Wang, L. Goel, X. Liu, and F. H. Choo. **Harmonizing AC and DC – A Hybrid AC/DC Future Grid Solution**. *IEEE Power and Energy Magazine*, 11(3):76–83, May 2013. ISSN 1540-7977.

[158] H. W. Weber, M. Hladky, T. Haase, S. Spreng, and C. N. Moser. **High Quality Modelling of Hydro Power Plants for Restoration Studies**. In *15th IFAC World Congress*, 2002.

[159] H. W. Weber, H. P. Asal, and E. Grebe. **Characteristic Numbers of Primary Control in the UCPTE Power System and Future Requirements**. In *ETG '97 Summer Meeting*, pages 395–405, July 1997.

[160] T. Weißbach and E. Welfonder. **High Frequency Deviations Within the European Power System – Origins and Proposals for Improvement**. *ELECTRA*, 242:9–15, 2009.

[161] E. Welfonder, B. Hall, W. Glaunsinger, and R. Heueck. **Untersuchung der frequenz- und spannungsabhangigen Leistungsaufnahme von Verbraucherteilnetzen – Ergebnisse und Folgerungen fur den Verbundbetrieb**. *Elektrizitatswirtschaft*, 93(3):81–87, 1994.

[162] N. Zhou, P. Etingov, Y. Makarov, R. Guttromson, and B. McManus. **Improving Area Control Error Diversity Interchange (ADI) Program by Incorporating Congestion Constraints**. In *2010 IEEE PES Transmission and Distribution Conference and Exposition*, pages 1–8, April 2010.

[163] P. Zolotarev, M. Gökeler, M. Kuring, H. Neumann, and E.-M. Kurscheid. **Grid Control Cooperation – A Framework for Technical and Economical Cross-Border Optimization for Load-Frequency Control**. In *Cigré 2012 Session*, C2-107, 2012.

A. Effects of Distorting Trading on Frequency Control

This appendix investigates distorted incentives that stem from imperfections in the market design which BRPs can use to undermine energy balancing principles in favour of gaming opportunities between the domestic imbalance energy pricing and international wholesale markets. These incentives are evaluated using historical data from the Swiss power system which features a typical European imbalance pricing mechanism. The results imply that between 2009 and 2012, little effort would have been needed to achieve a large profit at the expense of system security. This major loophole arose from the interdependence of cross-border trading and national imbalance energy pricing. As a consequence, only historical data from the Swiss power system between 2013 and 2015 were used for the imbalance modelling in Chapter 4.
Parts and results of this appendix have been published in [72, 125, 129].

A.1. Motivation and Switzerland as Modelling Basis

In Switzerland, the market is only partially liberalised. Most end-consumers receive full service provision from BRPs which replaced the utilities that formerly operated under monopolistic structures. There were three BRPs managing a contiguous geographical area, which makes their load forecasting represent a largely ideal behaviour, which resembles the load forecasting behaviour of a TSO for two reasons:

1. Swiss BRPs, which replaced integrated utilities, do not rely on standard load profiles but perform an actual load forecasting or load-

following [10]. As a consequence, Switzerland features low load forecast error in comparison to, for example, Germany where BRPs largely rely on standard load profiles. This was also reflected in the overestimation of the manual reserves dimensionality to compensate for load forecast errors [6,75].

2. The Swiss TSO does not publish the imbalance in real-time. Therefore, BRPs are not aware of the current imbalance situation in Switzerland; their objective is zero imbalance. Countries such as Austria, Germany, and the Netherlands publish the control area's imbalance close to real-time, which motivates BRPs to support the TSO in balancing the system by provoking an imbalance that supports the active power reserve activation of the TSO; however, this leads to a vastly different kind of behaviour, which would not allow the use of BRP behaviour to model residual load behaviour of a TSO.

To validate the working assumption that the large Swiss BRPs can serve as input for calibrating the imbalance modelling, the distorted incentives of BRPs were examined in the course of this thesis. The term "distorted incentives" encompasses all BRP motives for intentionally breaking or exceeding their energy balancing responsibility. The imbalance pricing mechanism between 2009 and 2012 turned out to have some design flaws. The respective loopholes are examined, and the following questions will be answered:

1. What are possible distorted profit strategies for BRPs to exploit imbalance energy pricing?

2. What is the maximum impact in quantities of money that these distorted profit strategies of BRPs had?

3. What are the appropriate remedies against trading strategies that undermine balancing principles?

First, the questions are discussed in terms of general application, i.e. from a European perspective. Second, historical data of the Swiss power system from 2011 and 2012 are analysed.

A.2. The Swiss Imbalance Pricing Mechanism

Until the end of 2012, the Swiss imbalance pricing mechanism was a dual-price system in which the price of imbalance energy was classified according to the direction of a BRP's discrepancy; the price paid by BRPs with a shortage was higher than the one the Swiss TSO paid to the BRP for a surplus within the same time period. In addition, the pricing mechanism took into account the effect the BRP had on the control area: It rewarded BRPs with a stabilising imbalance on the system and punished BRPs with a destabilising imbalance. Figure A.1 outlines the Swiss imbalance pricing mechanism.

The following example illustrates this principle: In the case that the control area is short and simultaneously a BRP's infeed is lower than its scheduled energy, the BRP has a destabilising imbalance. Due to this behaviour, the TSO has to activate control power, for example, AGC. The price the BRP has to pay for its imbalance afterwards is based on the price of the deployed control energy (ϕ^{cp}) affected by the lever α_1. As the BRP is short of energy, $\alpha_1 > 1$, implying that BRP always pays more for imbalance energy than it might have received in advance for the provision of control power. Until the end of 2012, there were no negative prices in Switzerland and the price for AGC energy was calculated to be the Swiss day-ahead spot price $\phi^{\text{spot}}\pm 20\,\%$. Therefore, Swiss BRPs generally have a financial incentive to keep their portfolio balanced as well as possible, i.e. not to have any open positions, as they pay at least $20\,\%$ times α_1 more for imbalance energy than for the same amount on the domestic spot market: The imbalance pricing mechanism is meant to inherently motivate a BRP to support the Swiss TSO in balancing the system. This principle can be transferred to other imbalance situations accordingly: If the BRP's behaviour is increasing the overall imbalance, the imbalance price is based on control energy prizes and, furthermore, if the BRP is short (long), the respective lever is $\alpha_1 = \alpha_4 > 1$ ($\alpha_2 = \alpha_3 < 1$). The four levers have been changed only once since the pricing mechanism was introduced. Between 1 January 2009 and 30 June 2009 $\alpha_1 = \alpha_4 = 1.01$ and $\alpha_2 = \alpha_3 = 0.99$. Between 1 July 2009 and 30 November 2012 $\alpha_1 = \alpha_4 = 1.3$ and $\alpha_2 = \alpha_3 = 0.7$.

As far as gaming is concerned, one aspect has to be considered: Spot market prices result from the day-ahead trading, and thus are known to all market parties the evening before the day of delivery. For this reason, the imbalance energy price is determined by the spot price as long as it is only

		Control area	
		Shortage	Surplus
BRP	Shortage	BRP pays[1] $\phi^{\text{cp}} \cdot \alpha_1$ $(\approx 1.2 \cdot \phi^{\text{spot}} \cdot 1.3)$	BRP pays[2] $\phi^{\text{spot}} \cdot \alpha_4$ $(= \phi^{\text{spot}} \cdot 1.3)$
	Surplus	BRP receives[2] $\phi^{\text{spot}} \cdot \alpha_2$ $(= 0.7 \cdot \phi^{\text{spot}})$	BRP receives[1] $\phi^{\text{cp}} \cdot \alpha_3$ $(\approx 0.8 \cdot \phi^{\text{spot}} \cdot 0.7)$

[1]destabilising effect [2]stabilising effect

Figure A.1.: The Swiss imbalance energy mechanism between 2009 and 2012 (numbers and approximations in brackets for 2011 and 2012).

AGC that is activated. Therefore, the imbalance energy price is known at the same time the spot prices are known. In contrast to this, manual reserve energy is auctioned separately by the Swiss TSO according to a merit order. The prices are published the week after delivery. Neither price curve nor time and amount of activated RR are known before real-time. However, as the proportion of time during which manual reserves are activated is comparatively small, BRPs often have a good guess at imbalance energy prices after gate closure of the Swiss day-ahead market. But to what extent can this setup be used to create gaming opportunities on foreign wholesale markets?

A.3. Identifying Distorted Incentives

Figure A.2 classifies distorted strategies of BRPs related to the imbalance pricing mechanism: This is a non-exhaustive classification and the application of such a strategy may depend on the regional market design. There are four fields of distorted incentives that a market design may reveal. All but risky arbitrage require a BRP to have access to a production or load portfolio, and all can be related to an intentional surplus ("over-supply") or shortage ("under-supply") position of a BRP. Such behaviour is generally not in line with current abuse-clauses, as BRPs should not be allowed to financially optimise in favour of an intentional imbalance. But in reality

Trading, demand, production

Trading

- Risky arbitrage

Demand, production

- Ancillary services
- System-destabilising unit commitment
- Real-time control

Figure A.2.: Classification of fields of distorted strategies that can facilitate gaming opportunities for BRPs in the imbalance pricing mechanism.

it is not easy to distinguish, whether a BRP is intentionally provoking an energy surplus (or shortage) or inadvertently deviating from the scheduled net energy balance. The only setup in which this can clearly be identified is one where BRPs have no metering points, but only trade, i.e. are mere traders. In theory, their net energy balance must always be zero, as elaborated in Section 2.3.2.

Risky Arbitrage

Arbitrage is the practice of taking advantage of price spreads between two or more markets. Textbook arbitrage is self-financing trading that has a positive current payoff and a zero payoff at a known future point in time, i.e. arbitrage is meant to be riskless. In practice, risky arbitrage is more common; it is self-financing trading with a positive current payoff but a zero payoff at an unknown future point in time. Within the scope of distorted incentives in energy balancing, arbitrage is possible between wholesale market trading and the imbalance energy pricing if the price for imbalance energy is known: Market participants can have open positions and accept to pay for imbalance energy. Obviously, this is not the intention of an imbalance pricing scheme, as it is supposed to incentivise BRPs not to have any open positions. Hence the wholesale energy price is generally higher than the imbalance energy price; however, arbitrage is possible if markets with energy prices below the domestic imbalance energy can be accessed. As imbalance energy prices are mostly settled after real-time, a BRP will not know the precise amount of energy that can be traded before the imbalance energy price converges, and therefore, inherently only risky arbitrage is possible.

Different strategies with different levels of complexity related to imbalance energy can be identified: Not all countries have negative prices for energy, i.e. delivering energy may cost money. This may lead to situations in which energy can be purchased in one country for a negative price, and an intentional surplus position of a BRP in a neighbouring country does not get priced or even results in additional winnings. The same can apply to the price difference between imbalance energy and intraday prices, as pricing mechanisms differ from country to country. In any case, a market participant has to have access to BRPs in different countries.

Ancillary Services

With regard to ancillary services, manual active power reserves in particular, i.e. RR, can be subject to distorted trading. The activated amounts are generally higher compared to automatic reserves, and their deployment time is longer. A market participant managing a BRP and also offering ancillary services with the same power plant portfolio is a prerequisite: A BRP may trigger an activation of reserves by creating an intentional shortage, for which an incentive would be an imbalance energy price that is below the control energy price. Furthermore, there is an incentive not to deliver requested reserves if the penalty for a non-delivery is below the imbalance energy caused by this additional deviation.

System-Destabilising Unit Commitment

A BRP which does not offer ancillary services can nonetheless be the source of a system-destabilising unit commitment: A power plant portfolio allows BRPs to have flexible production and non-standardised products; however, this flexibility can also cause imbalances. In this context, system-destabilising unit commitment refers to the capability of triggering imbalances that require the activation of active power reserves by TSOs. A common example are imbalances induced by the market at the full hour in order to minimise the imbalance energy. The results are very fast ramping gradients that cannot be compensated by active power reserves (see Section 2.3.3).

Flexible hydropower in particular is predestined to encourage gaming with price correlations. For example, if the wholesale energy price drops below the forecasted production price, power plants stop producing. A pump-storage hydro power plant could switch from turbine to pump mode without buying energy for this change in demand, which creates a shortage for the BRP. Another opportunity arises if there is no market liquidity or incentive for a BRP to compensate a loss of load or production within the requested time frame. In this case it will intentionally not take any measures to compensate the loss but cover it with imbalance energy.

Real-Time Control

The following approach is different from the ones explained above. So far all outlined approaches aim at intentionally breaking the balancing responsibility. In addition, the balancing responsibility could be exceeded, which is referred to as real-time control. It takes place if a BRP sets up a control structure for operating its individual load-frequency control, which is actually part of the TSO's responsibility. Real-time control is not to be confused with load-following operation, where a BRP uses real-time measurements to compensate for short-term forecast errors. The precise demarcation depends on the real-time data a BRP uses and the control structure it implements. However, real-time control is considered a distorted incentive, as it interferes with the TSO's responsibility.

A.4. Results of Evaluating Distorted Incentives

After a general classification of possible distorted behaviour, specific strategies for the Swiss power system will be evaluated and it will be shown which of these could have been profitable in the past. This will be done with the help of historical data from 2011 and 2012 including Swiss day-ahead prices (SwissIX), Swiss imbalance energy prices, the ATC one hour before delivery at the Swiss-German border, as well as the bids and prices of the German intraday market. Bids and prices are publicly available. The ATC is calculated according to trading records.

A.4.1. Exploiting Price Spreads

In a discussion of distorted strategies, the possible markets are of interest. Figure A.3 shows day-ahead and intraday markets of the four neighbouring control areas of Switzerland. Intraday markets are of special interest, as these offer a possibility for short-term trading and optimisation:

- The Swiss day-ahead price is known, and so are most of the possible imbalance energy prices.
- Cross-border capacity is free of charge for intraday trading.

The Italian intraday market is very limited in its possibilities, as only two gate closures take place intraday and as only hourly products are traded.

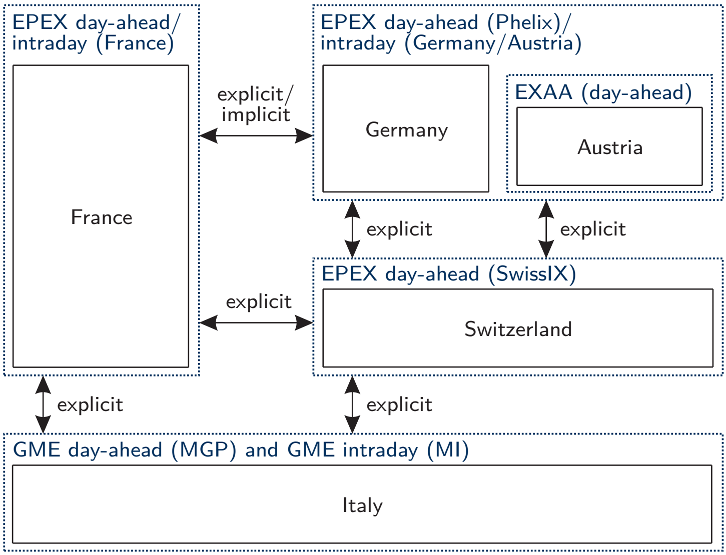


Figure A.3.: Assessable markets for Swiss BRPs; cross-border capacity can be allocated implicitly or explicitly (dated 2012).

	2014	2013	2012	2011
Day-ahead trading volume [TWh]				
Germany/Austria	262.9	245.6	245.3	224.6
France	67.8	58.5	59.3	59.7
Switzerland	20.5	18.7	16.7	12.1
Intraday trading volume [TWh]				
Germany/Austria	26.4	19.7	15.8	15.9
France	3.3	2.9	2.2	1.7
Switzerland	1.1	0.5	–	–
Share of intraday trading [%]				
Germany/Austria	9.1	7.4	6.1	6.6
France	4.6	4.7	3.6	2.8
Switzerland	5.1	2.6	–	–

Table A.1.: Trading volumes in Germany / Austria, France, and Switzerland between 2011 and 2014 [54,56].

The French intraday market has low liquidity which does not exceed 5 % of the day-ahead volume and only offers half-hourly products, as shown in Table A.1. The German intraday market offers quarter-hour products and has comparatively higher maximum liquidity which is approximately 10 %. Consequently, the German-Austrian intraday market is the market of interest for Swiss BRPs.

In the following, it will be analysed to what extent a Swiss BRP could have exploited the imbalance pricing mechanism by leaving positions open, i.e. doing a trade without a countertrade, and accepting that it will cause a physical imbalance in the system. This could either be done by a trader without physical assets or by a utility that owns a production portfolio. Both have the same physical effect and are referred to as gaming opportunities.

A.4.2. Import Surpluses to Switzerland

The most obvious incentive for gaming arises when German-Austrian spot prices are negative. However, in 2011 there were only 41 h and in 2012 only 38 h of negative prices in Germany. Obviously, every situation could be financially beneficial in which the German intraday price, ϕ^{Germany}, is below the Swiss imbalance energy price. Since the latter is usually directly proportional to the day-ahead spot price, ϕ^{spot}, it can be estimated using

	Profit based on estimated prices in euros	Profit based on real prices in euros
2011	4 360 826	5 316 692
2012	1 853 365	12 454 939
Total	6 214 191	17 771 631
Total projected onto Europe[1]	50 442 718	144 258 420

Table A.2.: Comparison between the strategy of importing surpluses with a constant estimation coefficient of 0.56 and the maximum possible profit if the real imbalance energy prices had been known.

a coefficient, q^{imp}; and the price spread has to satisfy Formula A.1.

$$\phi^{\mathsf{DE}} < \phi^{\mathsf{spot}} \cdot q^{\mathsf{imp}} \tag{A.1}$$

First of all, the control energy price, ϕ^{cp}, is approximated by the AGC energy price as explained in Appendix A.2. Therefore, $q^{\mathsf{imp}} = 0.56$ in the case of a destabilising BRP, i.e. 0.8 times α_3. Based on this approximation, it is assumed that whenever Formula A.1 is satisfied one hour before real-time delivery, energy is bought on the German market and the resulting energy surplus is left in the Swiss control area. Energy imports are limited by the available market volume and the ATC one hour before delivery on the Swiss-German border.

Table A.2 shows the results of this first strategy and compares the numbers to the potential profit BRPs could have made if they had known the real imbalance energy price in advance. A rough projection onto Europe indicates a large possible financial impact if similar strategies had been applied all over Europe. However, this projection does not consider the difference in market design and is meant to illustrate the expected amount for larger market areas.

The results for Switzerland show that a simple strategy results in 35 % of the maximum possible winnings for the two years considered. However, in 2011 it was quite a robust approach, whereas in 2012 only 15 % of the maximum could have been realised. This is due to the participation of

[1] The extrapolation is done by disproportionately scaling the total to the European peak load of 532.6 GW in 2011 [43].

Switzerland in the German grid control co-operation, which influenced the activation of control power. Subsequently, the choice of q^{imp} needs further screening: What is the best coefficient for both years? To answer this and to sketch a realistic scenario, more parameters are needed.

First, a maximum market volume the BRPs can buy has to be defined. As price elasticity on a spot market is very low, it is assumed that the market clearing price is inflexible up to a change of 20 % of the market volume, i.e. the price does not change significantly [14,41]. Figure A.4a shows how the choice of q^{imp} influences the overall profit when buying 20 % on the market at a maximum. For both years the profit is at the maximum when q^{imp} is 0.58, which is close to the initial choice of 0.56. However, there is no limit to the overall imbalance of a BRP. A large imbalance is noticeable to the TSO which normally monitors BRP behaviour. A more realistic ambition is that a BRP limits its maximum intentional imbalance. According to an internal analysis, the imbalance energy of large Swiss BRPs, comprising production and demand, exhibits a standard deviation of approximately 50 MW. If a long or short position is kept close to the standard deviation, it will be hard to find evidence for its intentionality. Figure A.4b plots the profit against the estimation coefficient q^{imp}, when limiting the maximum imbalance to 50 MW.

This underscores the results shown in Table A.2; the simple estimation lost its robustness in 2012. The best coefficient for 2011 is still the same, whereas the one for 2012 differs significantly: If $q^{\text{imp}} = 0.58$ is assumed for both years, the profits are 210 055 and 130 260 euros, respectively. Both numbers are significantly below the maximum shown in Table A.2.

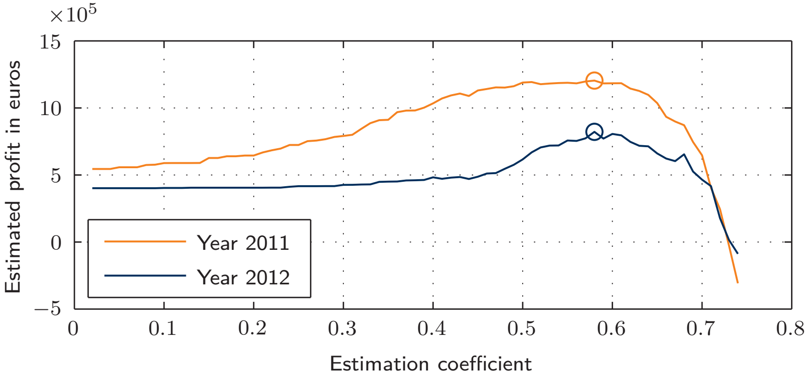
A.4.3. Export Surpluses from Switzerland

Appendix A.4.2 outlined a plain approach to profiting from intentional surpluses in Switzerland that usees a constant estimation coefficient. Before analysing granularity, the same approach is applied to exporting surpluses, i.e. importing shortages to Switzerland.

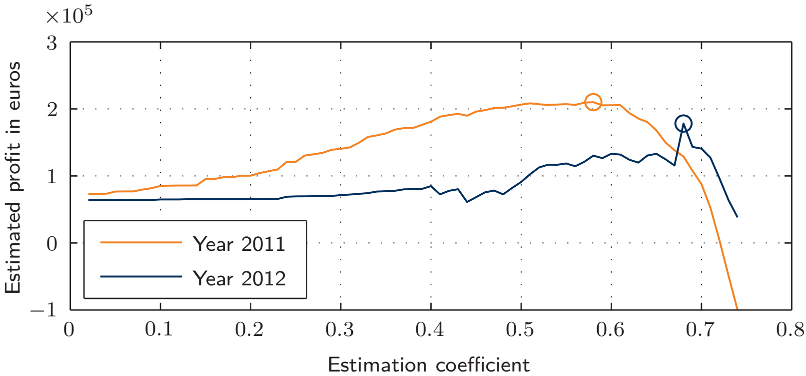
Similar to Formula A.1, an estimation coefficient q^{exp} can be used to find beneficial situations for exporting surpluses:

$$\phi^{\text{Germany}} > \phi^{\text{spot}} \cdot q^{\text{exp}} \tag{A.2}$$

The idea stays the same: If Formula A.2 is satisfied one hour before intraday delivery, energy is sold in Germany in order to create an intentional



(a) The yearly profit made by importing surpluses as a function of the estimation coefficient q^{imp}; the maximum energy that can be bought is limited to 20 % of the total market volume.



(b) The yearly profit made by importing surpluses as a function of the estimation coefficient q^{imp}; the maximum imbalance and energy that can be bought is limited to 50 MW and 20 % of the total market volume, respectively.

Figure A.4.: The yearly profit made by importing surpluses as a function of the estimation coefficient.

	Profit based on estimated prices in euros	Profit based on real prices in euros
2011	693 222	5 057 689
2012	106 066	53 593 230
Total	799 289	58 650 920
Total projected onto Europe	6 488 103	476 089 620

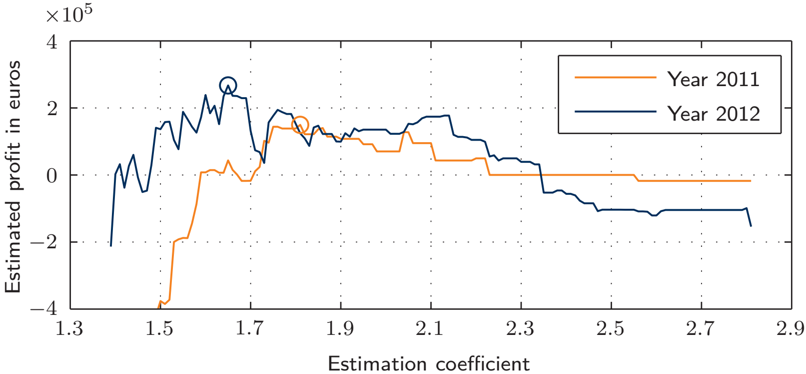
Table A.3.: Comparison between the strategy of exporting surpluses with a constant estimation coefficient of 1.56 and the maximum possible profit if the real imbalance energy prices had been known.

shortage in Switzerland, i.e. the short position will be invoiced according to the Swiss pricing model for imbalance energy.

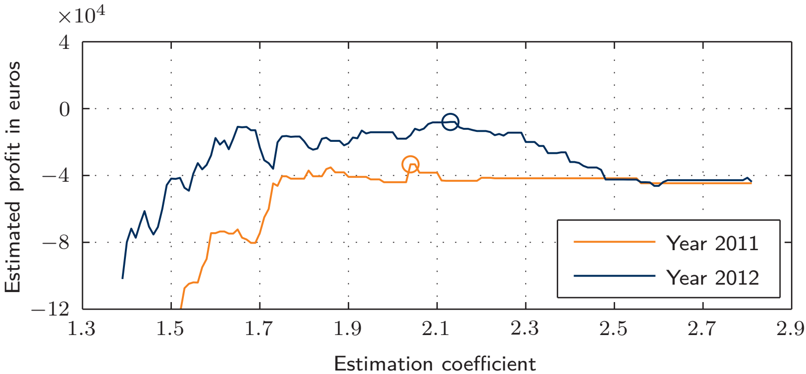
The simplest choice is $q^{\text{exp}} = 1.56$ in the case of a destabilising BRP according to Appendix A.2. Table A.3 shows the results of this strategy and compares the numbers to the potential profit BRPs could have made if they had known the real imbalance energy price. Again a rough projection onto Europe indicates a large possible financial impact.

For Switzerland, the difference between strategy (estimated prices) and theoretical maximum (real prices) is even greater when compared to the importing approach. However, the resulting numbers are still tempting. For a more realistic scenario, the same constraints are applied as before. The limiting market volume is set to 20 %. The results are displayed in Figure A.5a. The difference in the offset between 2011 and 2012 is similar to the one observed in Figure A.4a, but both functions are considerably less smooth, and therefore, less robust. This becomes more obvious if the above-mentioned limit of the maximum imbalance of 50 MW is applied: Figure A.5b shows only losses.

This is due to the generally large difference between the imbalance energy price and the SwissIX price when the latter is comparatively low. Exporting surpluses leads to an activation of negative reserves for which the Swiss TSO has to pay. The price for negative manual control reserves is mostly above spot prices and the one for positive manual control reserves mostly below spot prices, i.e. an ancillary service provider will offer low prices for negative control energy, but high prices for positive control energy. Subsequently, the activation of negative manual reserve power has



(a) The yearly profit made by exporting surpluses as a function of the estimation coefficient q^{exp}; the maximum energy that can be bought is limited to 20 % of the total market volume.



(b) The yearly profit made by exporting surpluses as a function of the estimation coefficient q^{exp}; the maximum imbalance and energy that can be bought is limited to 50 MW and 20 % of the total market volume, respectively.

Figure A.5.: The yearly profit made by exporting surpluses as a function of the estimation coefficient.

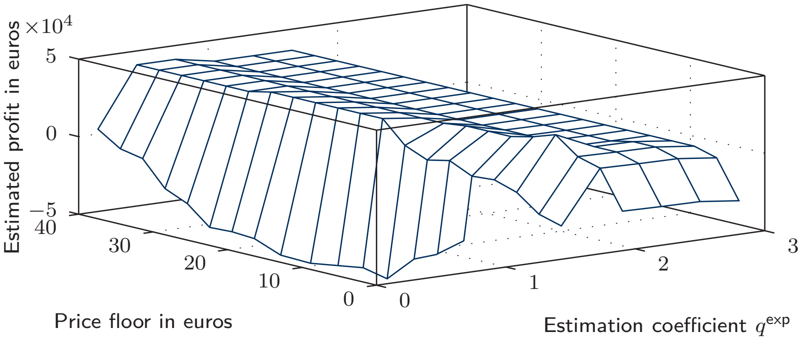


Figure A.6.: The yearly profit made by exporting surpluses in 2011 as a function of the estimation coefficient q^{exp} and the price floor; the maximum imbalance and energy that can be bought is limited to 50 MW and 20 % of the total market volume, respectively.

little influence on the imbalance energy price, whereas the activation of positive RR has a comparatively strong impact on the imbalance energy price. This effect becomes amplified when spot prices are low. In such a situation, it is manual control energy alone that determines the balancing price. The production structure in Switzerland is dominated by hydroelectricity and nuclear power. The variable costs of both are low; therefore, manual control energy prices are quite independent of the Swiss spot price: Compared to FRR, the market for RR is large, but the proportion of the time during which manual reserves get activated is comparatively small. Prices for the provision of manual reserves are lower than those for AGC resources. Manual control energy prices are very high for positive reserves and close to zero for negative reserves. That implies that providers have little interest in deploying any energy, i.e. hydropower will save the water, and – in opposite to AGC – money is made by provision rather than by activation.

Furthermore, it can be observed when SwissIX prices are low, the Swiss control area is likely to be short, i.e. exporting surpluses would further destabilise the system. At a first glance, this may sound contradictory: Why should load-supplying BRPs be short of energy when the price is low? Again, this is owed to the operational flexibility of hydroelectricity:

When the spot price is below 20 euros/MWh, Swiss power plant operators tend to reduce the output of their power plants; producers save water to utilise it later on for the production of well-paid peaking power. However, this strategy is only used when spot prices are low, as the risk of having to pay higher imbalance prices increases the higher spot prices are. This obstacle can be overcome by choosing an appropriate floor price for the exporting strategy. To find an appropriate limit, an in-depth analysis of data from 2011 is performed: Figure A.6 shows the estimated profit plotted as a function of the estimation coefficient and price floor. The profit is largest at an estimation coefficient of $q^{\text{exp}} = 1.9$ and a floor price between 8 and 11 euros, which results in 14 519 euros for 2011. Applying the same parameters to 2012 results in 41 119 euros. These numbers are small in comparison to those for importing surpluses: This strategy does not offer much profitability. Furthermore, this shows a limitation of the estimation approach: The impact of a constant estimation factor is small if it is multiplied by a low price: With its exporting strategy, a BRP wants to profit from low prices but the estimation coefficient has a poor effect. For the importing strategy, on the other hand, high prices are of interest and the estimation factor has considerable impact on the profit.

A.4.4. Daily Patterns

Up to now, long-term profits have been of interest; therefore, only yearly estimation coefficients were used. In order to understand the dynamics behind the strategies and the reason for their success and failure, the importing and exporting strategies are analysed and compared in more detail.

The results in Appendix A.4.3 already indicate that the exporting strategy may not offer much potential for short-term profits: There were only 11 h in 2011 and 26 h in 2012, when this strategy might have been successful. The numbers for the importing strategy are significantly different: 1649 h (2011) and 1410 h (2012). Therefore, it only makes sense to analyse the importing strategy in order to find a pattern.

Figure A.7 shows the average estimation coefficients per hour for both years. A certain daily pattern is visible but it varies from one year to the next due to the manual reserve activation pattern and the participation in the German grid control co-operation (see Appendix A.4.2). Theoretically, the profit would be 225 744 and 382 259 euros indicating an increase of 78 % as compared to the use of a constant coefficient. But as the correla-

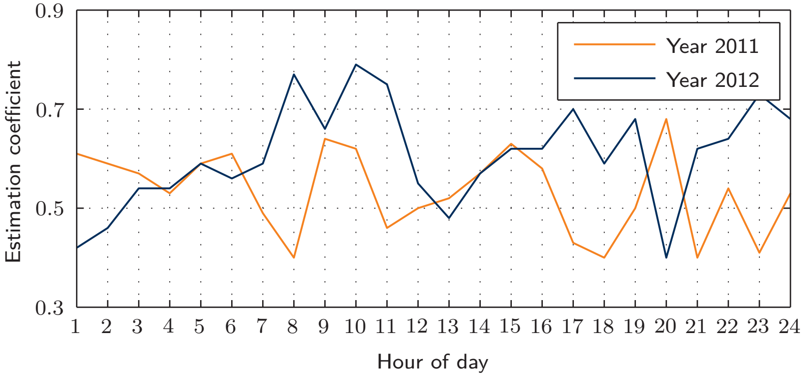


Figure A.7.: Average estimation coefficient q^{imp} per hour; the maximum imbalance and energy that can be bought is limited to 50 MW and 20 % of the total market volume, respectively.

tion between the years is weak, it is virtually impossible to forecast hourly coefficients: If the 2011 values are applied to 2012 data, the result is a profit of 103 605 euros, which is very much lower than the profit based on a constant yearly coefficient.

Figure A.8 shows which parts of the day offer a potential for profit using a constant estimation coefficient of 0.58. Obviously, the strategy is robust for certain hours, whereas the possible profit is small or even negative for midday and evening hours. These hours should be avoided in order to minimise the risk of losses, which means that the imbalance energy mechanism is robust during these hours.

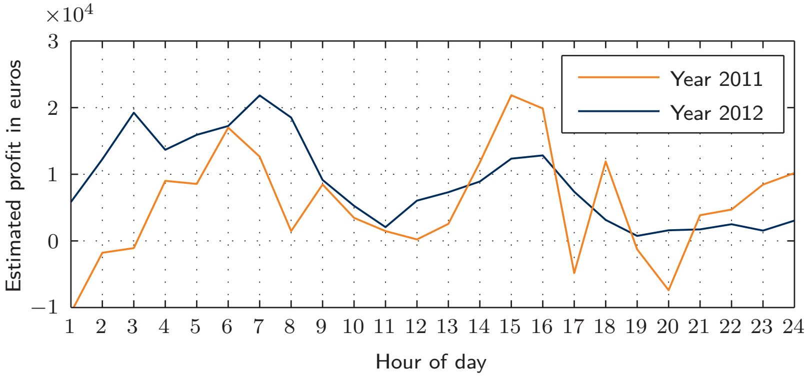


Figure A.8.: Estimated profit per hour by importing surpluses for an estimation coefficient $q^{\mathrm{imp}} = 0.58$; the maximum imbalance and energy that can be bought is limited to 50 MW and 20 % of the total market volume, respectively.

B. Modelling Data

This appendix describes the parameters used to calibrate the Continental European power system.
Parts of this appendix have been published in [35,123,128,130].

B.1. Dynamic Frequency Model

For the simulations in this thesis, different configurations with different levels of detail were used, as discussed in Section 3.2.2. The dynamic model was used for frequency-response analyses and bias factor sizing. Figure B.1 shows the model used for the latter. The area blocks contain FCR, load self-regulation, and a first order delay modelling the FRR power plants. The system frequency deviation is a result of the one common system inertia block, where f_0 is the nominal frequency, S_B the total rated power, H^tot the total inertia constant, and s the Laplace transformation variable. The mismatch between electrical and mechanical power, which defines the input of the system inertia block, is the difference between the power of the outage in the second area and the frequency-dependent change in power in all areas. Note that during an outage in the second area, no other disturbances occur.

B.2. Reliability and Unit Parameters

Typically, no plant-specific failure statistics are collected centrally in Europe. In the course of working on this thesis, forced outage rates were collected for Belgium, Croatia, the Czech Republic, France, Germany, the Netherlands, Poland, Spain, and Switzerland. The enquiry period was not specified. Belgium collected the statistics between 2009 and 2010, France between 2004 and 2008, and Poland for 2010. The others did not indicate any enquiry period. The German values are identical to the ones

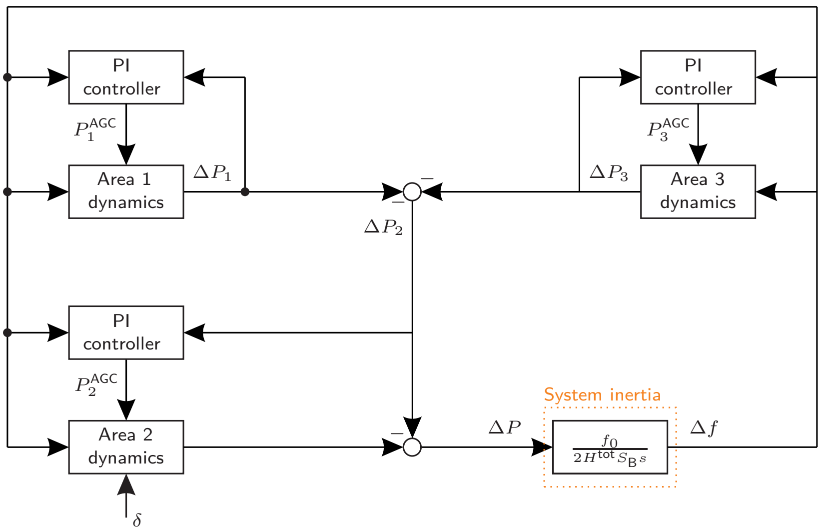


Figure B.1.: The dynamic frequency model used for frequency-response analyses and bias factor sizing.

published in [77], and based on records kept between 1988 and 2006 by VGB PowerTech e.V. – a voluntary European technical association of companies for power and heat generation. Only the basic technologies have been listed separately, and the generating units are neither classified by manufacturer nor by commissioning date. Table B.1 summarises the yearly forced outage rates per country and the number of respective units per country.

Based on these numbers, generally applicable weighted average values are calculated as shown in Table B.2. Furthermore, these numbers do not take into account country-specific variations[1] and any possible dependency on the unit's nominal power. Failures caused by system components such as bus bars and transformers are not considered, as the network topology is not explicitly taken into consideration.

[1] For example, pumped-storage hydroelectric generation generally has a must-run share, whereas a recirculating-storage hydro has no significant must-run share: The classification depended on self-declaration and could not be tracked in detail.

	BE	CH	CZ	DE	ES	FR	HR	NL	PL
Nuclear	1.75 (7)	0.75 (5)	2.00 (3)	1.10 (9)	4.00 (8)	1.49 (56)		2.00 (1)	
Hard coal	8.05 (17)		15.30 (3)	6.60 (96)	10.00 (25)		4.00 (3)	10.00 (9)	6.99 (40)
Lignite				4.50 (62)					9.08 (37)
Gas / oil				3.90 (15)			2.00 (7)		
Combined cycle gas turbine	4.66 (8)			12.10 (27)				8.00 (22)	
Gas				2.50 (101)				18.00 (13)	
Hydro	1.00 (7)	0.50 (184)							

Table B.1.: Forced failure rates for different kinds of power plants in the RGCE; numbers in brackets indicate the number of units based on which the statistics were gathered.

B.3. Reserve Activation and Provider Dynamics

Provider Dynamics

Depending on the type and technology of a unit, the dynamics of units providing ancillary services can differ vastly. For example, the transfer function of a non-reheat steam turbine is a first order system, re-heaters cause an additional delay in the system, and the dynamics of a hydro power plant feature a non-minimum phase behaviour [5,91,158]. Detailed modelling of generating units is the subject of several in-depth studies; it also requires detailed data not only on the power requested and delivered, but also on the input and output power of each individual machine. Such data sets are generally not available. In the scope of this thesis, the dynamics are simplified based on the following assumptions and observations:

- The adjustment of the set-point of a turbine due to AGC is slow, a significant non-minimum phase behaviour does not occur in practice.
- Typically, the AGC signal from the TSO is routed to multiple units.

	Average force outage rate	Base load	MTTR	Merit order position	Number of units
Combined cycle gas turbine	9.47	50 %	23 h	7th	61
Gas	4.27	50 %	122 h	6th	227
Gas / oil	3.30	60 %	122 h	5th	128
Hard coal	7.50	40 %	52 h	4th	345
Pumped-storage hydro	0.52	40 %	24 h	8th	20
Recircu-lating-storage hydro	0.52	10 %	24 h	9th	434
Must-run hydro	0.52	50 %	24 h	2nd	281
Lignite	6.21	60 %	33 h	3rd	178
Nuclear	1.68	100 %	87 h	1st	112

Table B.2.: Statistics and parameters of the generation portfolio of different kinds of units for the RGCE.

The precise handling is often up to the BSP (or BRP) and only limited by TSO-specific requirements tested during pre-qualification [131].

- In particular, the dynamic behaviour shapes the behaviour at a second level, and in addition, providers driven by future power electronics may affect the AGC provider dynamics; however, verified information on any future developments is not available, nor is the behaviour at a second level of any interest to this thesis.
- As discussed in Section 3.2.2, the calibration of the AGC loop leaves several degrees of freedom to the TSO and these are passed on the providers. During normal operation, each TSO is required to implement classic AGC, which has to respond within 30 s after the occurrence of a disturbance and reduce the ACE to zero within 15 minutes without any significant overshoot [106].

Because of the above, simplified and pooled dynamics are used. In the simulations in Chapter 5, providing units respond to the AGC signal within the time step of 1 minute, and each area is assumed to activate its reserves by showing a proportional reaction within 5 minutes, i.e. $C_i = 0.1$ and $T_i = 300$ s. Both values are considered typical for the RGCE.

Reserve Activation

Note that the technical activation logic for FRR can be chosen without regard to the market structure and pricing. In practice, however, FRR are usually activated based on the energy price. For pay-as-bid offers, the units are activated according to merit order. In case of uniform pricing, all units offer their performance at the same price and are proportionally activated in parallel, i.e. pro rata. As the AGC control signal is typically sent to the n providers as a contribution factor g_i relative to their total offer, i.e. $g_i \in [0, 1]$, let $g = (g_i)$ be a vector of dimension n whose elements correspond to the n provider such that

$$g_i^{\text{mol}} = \begin{cases} \min\left\{\dfrac{P^{\text{AGC}} - \sum_{j=1}^{i-1} P_j^{\text{FRR}}}{P_i^{\text{FRR}}}, 1\right\} & \text{if } \sum_{j=1}^{i-1} P_j^{\text{FRR}} < P^{\text{AGC}}, \\ 0 & \text{otherwise,} \end{cases} \tag{B.1}$$

for a merit order activation logic, and

$$g_i^{\text{pro}} = \min\left\{\frac{P_i^{\text{AGC}}}{\sum_{i=1}^{n} P_i^{\text{FRR}}}, 1\right\} \tag{B.2}$$

for a pro rata activation logic, where P_i^{FRR} is the total amount of contracted reserves of provider i. The choice of activation logic does not add additional dynamics. Let $H^{\mathsf{FRR}}(s)$ be the transfer function for each reserve provider, and the total response is given by

$$\begin{aligned}\sum_{i=1}^{n} g_i^{\mathsf{mol}} P_i^{\mathsf{FRR}} H^{\mathsf{FRR}}(s) &= P^{\mathsf{AGC}} H^{\mathsf{FRR}}(s) \\ &= \sum_{i=1}^{n} g_i^{\mathsf{pro}} P_i^{\mathsf{FRR}} H^{\mathsf{FRR}}(s)\end{aligned} \tag{B.3}$$

Therefore, both activation logics lead to the same response for units that feature a common linear time-invariant behaviour. For non-linear characteristics such as ramping restrictions and response delays, Formula B.3 does not hold. In case of significant ramping limitations, merit order activation will provide a slower response. Nowadays, however, most countries have implemented a pro rata activation [26].

B.4. Nuclear Power Phase-Out

The schedule for the nuclear power phase-out in Belgium, Switzerland, and Germany is shown in Table B.3. The decision to nuclear to phase out nuclear power in Belgium was originally adopted in 1999. It stipulated that each of the seven reactors should be decommissioned after 40 years of operation and that no new reactors should to be built. The economic significance of nuclear power for the energy supply in Belgium was underestimated. The former decision was overturned and the operating permit of three reactors was extended for another 10 years. Current planning in Belgium anticipates completion of phase-out by 2025 [4]. As a reaction to the *Fukushima Daiichi* nuclear disaster, the Swiss government decided in 2011 to phase out nuclear by not extending operating permits beyond 2034, and there will be no permits for new reactors [36]. The nuclear power phase-out in Germany also started in 2011, when 8 of 17 reactors were permanently shut down and the government announced a plan to shut down the remaining reactors by the end of 2022 [145].

	Power plant	Nominal Power [MW]	Phase-out year
Belgium	Doel I	393	2025
	Doel II	393	2025
	Doel III	864	2022
	Doel IV	969	2025
	Tihange I	870	2025
	Tihange II	864	2023
	Tihange III	979	2025
Switzerland	Beznau I	365	2029
	Beznau II	365	2029
	Gösgen	970	2034
	Leibstadt	1165	2034
	Mühleberg	970	2019
Germany	Brokdorf	1370	2021
	Brunsbüttel	771	2011
	Krümmel	1260	2011
	Unterweser	1345	2011
	Emsland	1329	2022
	Grohnde	1360	2021
	Grafenrheinfeld	1275	2015
	Biblis A	1167	2011
	Biblis B	1240	2011
	KKP I (Philippsburg)	926	2011
	KKP II (Philippsburg)	1458	2019
	GKN I (Neckarwestheim)	757	2011
	GKN II (Neckarwestheim)	1395	2022
	Grundremmingen B	1284	2017
	Grundremmingen C	1288	2021
	Isar I	878	2011
	Isar II	1400	2022

Table B.3.: Historical and planned future decommissioning of nuclear power plants in Belgium, Switzerland, and Germany.

C. Ramped Schedules and Imbalance Energy

C.1. Share of Schedule-Based Operation

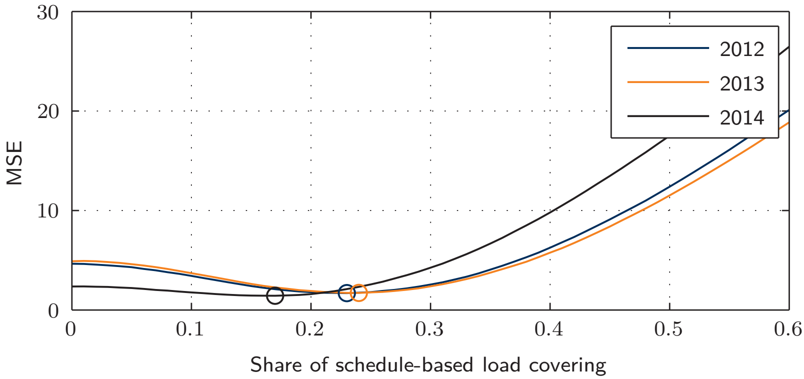
As discussed in Section 5.2.1, the share of schedule-based operation can be estimated by determining the amount of reserves. Figure C.1 shows the sensitivity of matching.

C.2. Incentive-Based Calculation of Imbalance Energy

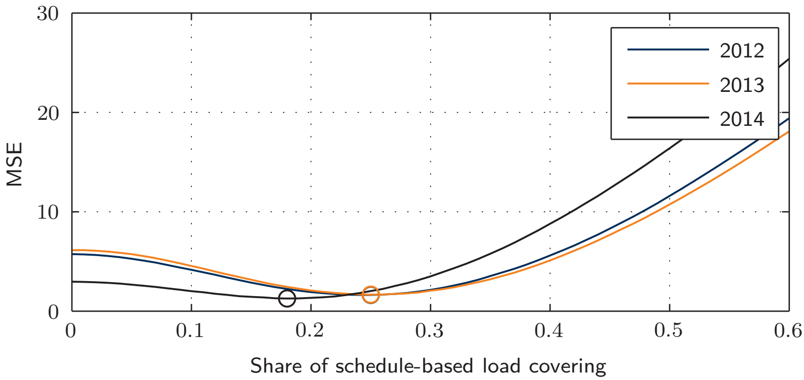
Figure C.2 illustrates in greater detail the difference between scheduled energy and actual energy if the ramping period is properly implemented.

C.3. Ramp Rates per Technology

The physical limitation of the current generation portfolio in each country does not limit the ability to instantaneously follow discrete schedule changes to a large degree. Based on the ramp rates per technology shown in Table C.1, the maximum ramp rate per country is estimated and summarised in Table C.2. These values are higher than the largest schedule change between two consecutive hours; for example, the largest expected generation gradient in France typically is at 6 a.m. and does not surpass 9 GW/h.



(a) Best-case scenario, i.e. adherence to local imbalance period.



(b) Conservative-case scenario, i.e. domination of hourly products.

Figure C.1.: Estimation of the share of schedule-based operation for 2012 to 2014.

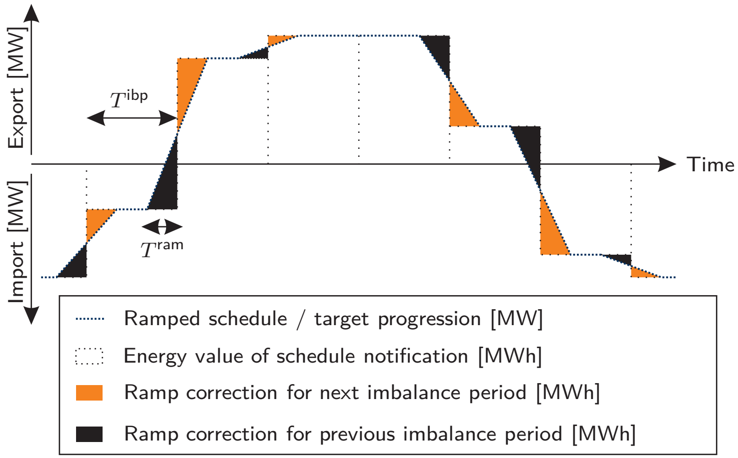


Figure C.2.: The difference between schedule and operational implementation as a result of the ramped schedule.

	Percentage per minute in reference to the nominal power
Combined cycle gas turbine	9 %
Gas	20 %
Gas / oil	15 %
Hard coal	5 %
Pumped-storage hydro	25 %
Recirculating-storage hydro	25 %
Must-run hydro	25 %
Lignite	5 %
Nuclear	10 %

Table C.1.: Estimated ramp rates per technology based on internal data.

Country	Ramping per minute [MW]
Austria	3520
Bosnia and Herzegovina	550
Belgium	1550
Bulgaria	1260
Switzerland	3880
The Czech Republic	970
Germany	11 030
Spain	11 660
France	12 180
Greece	1810
Croatia	270
Hungary	1540
Italy	7480
Montenegro	270
Republic of Macedonia	40
The Netherlands	2080
Poland	2000
Portugal	1530
Romania	2070
Republic of Serbia	210
Slovenia	200
Slovakia	1210

Table C.2.: Estimated ramping potential per country based on the generation portfolio between 2012 and 2014; as these values do not take into account the degree of utilisation and the operational point, they can be treated as maximum values.

D. Mathematical Tools

D.1. Multi-Objective Optimisation and Pareto Efficiency

In this thesis, various standard optimisation problem types have been used [16]. Their standard forms are:

Linear programming: The objective and all of the constraints are linear functions of the decision variables:

$$\text{minimise} \qquad \boldsymbol{f}^\top \boldsymbol{x} \quad \text{subject to} \begin{cases} \boldsymbol{B}\boldsymbol{x} \leq \boldsymbol{b} \\ \boldsymbol{l_b} \leq \boldsymbol{x} \leq \boldsymbol{u_b} \end{cases} \tag{D.1}$$

Quadratic programming: This has an objective which is a quadratic function of the decision variables and constraints which are all linear functions of the variables:

$$\text{minimise} \qquad \frac{1}{2}\boldsymbol{x}^\top \boldsymbol{F}\boldsymbol{x} + \boldsymbol{f}^\top \boldsymbol{x} \quad \text{subject to} \begin{cases} \boldsymbol{B}\boldsymbol{x} \leq \boldsymbol{b} \\ \boldsymbol{l_b} \leq \boldsymbol{x} \leq \boldsymbol{u_b} \end{cases} \tag{D.2}$$

For these problem types, a wide range of different algorithms is available:

Simplex methods: These methods move along the edges of the feasible set, i.e. polytope, to extreme points with increasing objective values. These values increase until the maximum value is reached or until an unbounded edge is found. An algorithm used in such a method always terminates, because the number of vertices in a polytope is finite. These methods work quite well in practice, but a (theoretical) worst-case complexity can take an exponential amount of time.

Interior-point methods: These methods, which are also referred to as "barrier methods", are a certain class of algorithms that solve linear and non-linear convex optimisation problems. Such an algorithm moves across the interior of the feasible region, and not along the boundary. State-of-the-art implementations usually work faster with large problems than simplex methods do.

With a multi-objective problem, the scalar concept of optimality cannot be applied directly. The notion of Pareto efficiency (or Pareto optimality) needs to be introduced [40,98]. Essentially, a solution is said to be Pareto optimal for a multi-objective problem if all other solutions show a higher value for at least one of the objective functions (a weak Pareto optimum or a weakly efficient solution), or show the same value for all objective functions (strict Pareto optimum or a strictly efficient solution).

D.2. Temporal Disaggregation

Temporal disaggregation methods are used to disaggregate low to higher frequency series, where either the sum, average, first or last value of the resulting series is consistent with the input series. As no indicator series are available, the challenge is to perform a non-model-based temporal disaggregation of the univariate load curve $\boldsymbol{P}^{\mathsf{L,ibp}}$ with a resolution of the imbalance period. A deviation at this frequency is defined by the forecast error, which gives preference to a mathematical smoothing method that treats the process of the higher frequency load curve as deterministic, i.e. binding. Boot et al. [15] propose a method for smoothing annual data to sub-annual data which can be generalised for load profiles.

Let $p_k^{\mathsf{L,pro}}$ be the estimation of the high resolution load curve with $1 \leq k \leq T$, where T is the total number of sub-periods in the high frequency load curve $\boldsymbol{P}^{\mathsf{L,pro}}$. For example, for an imbalance period T^{ibp} of 15 minutes, $T = 15$ for a profile with a resolution of one minute. Let $p_l^{\mathsf{L,ibp}}$ denote the load per imbalance period with $1 \leq l \leq m$, where m is the total number of load values in the sample. There are two possibilities for choosing the least square criterion. A first criterion is to minimise the sum of squares of the differences between successive values, subject to the constraint that during each imbalance period the average is equal to $p_m^{\mathsf{L,ibp}}$ such that

$$\begin{aligned} &\text{minimise} \quad \sum_{k=2}^{Tm} \left(p_k^{\mathsf{L,pro}} - p_{k-1}^{\mathsf{L,pro}}\right)^2 \\ &\text{subject to:} \\ &\frac{1}{T} \sum_{k=T(l-1)+1}^{Tm} p_k^{\mathsf{L,pro}} = p_l^{\mathsf{L,ibp}} \qquad 1 \leq i \leq m. \end{aligned} \tag{D.3}$$

By minimising the squared first differences, a continuously rising trend, for example, in the morning and evening hours, does not give a continuously rising straight line. Although this effect is a minor one, it would not have any physical meaning in an actual load profile. To avoid this, the objective function can be adjusted to minimise the squared second differences such that

$$\text{minimise} \quad \sum_{k=2}^{Tm} \left(p_{k-1}^{\mathsf{L,pro}} - 2p_k^{\mathsf{L,pro}} + p_{k+1}^{\mathsf{L,pro}}\right)^2, \tag{D.4}$$

where the same constraints apply as in Formula D.3.

D.3. Standard Distributions and Their Modifications

Poisson distribution: A discrete random variable X is said to have a Poisson distribution with parameter $\lambda > 0$ if the probability function of X is such that

$$f(k, \lambda) = p(X{=}k) = \frac{\lambda^k e^{-\lambda}}{k!}, \tag{D.5}$$

where $k \in \mathbb{N}_0$.

Truncated normal distribution: The truncated normal distribution is the probability distribution of a normally distributed random variable whose value is either bounded below or above (or both). It is used for practical application and to avoid computational errors, as values of a normally distributed random variable can, in theory, assume any value. Let x conditional on $x^{\text{min}} \leq x < x^{\text{max}}$ such that

$$f(x) = \begin{cases} 0 & -\infty \leq x < x^{\text{min}} \\ \frac{1}{\sqrt{2\pi\sigma}} e^{-\frac{1}{2}(\frac{x-\mu}{\sigma})} & x^{\text{min}} \leq x < x^{\text{max}} \\ 0 & x^{\text{max}} \leq x < \infty \end{cases} \tag{D.6}$$

Hyperbolic distribution: The one-dimensional generalised hyperbolic distribution has a probability density function such that

$$\begin{aligned} f(x, \lambda, \alpha, \beta, \delta, \tilde{\mu}) = a(\lambda, \alpha, \beta, \delta)(\delta^2 + (x - \tilde{\mu})^2)^{(\lambda - \frac{1}{2})/2} \\ \cdot J_{\lambda - 1/2}(\alpha\sqrt{\delta^2 + (x - \tilde{\mu})^2}) e^{\beta(x - \tilde{\mu})}, \end{aligned} \tag{D.7}$$

and

$$a(\lambda, \alpha, \beta, \delta) = \frac{(\alpha^2 - \beta^2)^{\lambda/2}}{\sqrt{2\pi}\alpha^{\lambda - \frac{1}{2}} \delta^{\lambda} J_{\lambda}(\delta\sqrt{\alpha^2 - \beta^2})}, \tag{D.8}$$

where J_λ is the modified Bessel function of the second kind, $x \in \mathbb{R}$, $\tilde{\mu}$ is a location parameter, δ is a scaling factor, and α and β determine the distribution shape[1]. In general, the mean value μ, the standard deviation σ, the skewness γ, and the kurtosis κ are given instead of α, β, δ, and μ. The conversion can be done such that

$$\mu = \tilde{\mu} + \frac{\beta\delta}{\sqrt{\alpha^2 - \beta^2}} \frac{J_{\lambda+1}(\zeta)}{J_\lambda(\zeta)} \tag{D.9}$$

and

$$\sigma^2 = \delta^2 \left(\frac{J_{\lambda+1}(\zeta)}{\zeta J_\lambda(\zeta)} + \frac{\beta^2}{\alpha^2 - \beta^2} \left[\frac{J_{\lambda+2}(\zeta)}{J_\lambda(\zeta)} - \left(\frac{J_{\lambda+1}(\zeta)}{J_\lambda(\zeta)} \right)^2 \right] \right), \tag{D.10}$$

[1] For additional details refer to the discussion of Fajardo and Farias [64] as well as Prause [112].

where $\zeta = \delta\sqrt{\alpha^2 - \beta^2}$. In case $\frac{\beta}{\alpha}$ is not too large, the simplification upholds such that

$$\gamma = \frac{3}{\sqrt{1 + \delta\sqrt{\alpha^2 - \beta^2}}} \cdot \frac{\beta}{\alpha} \tag{D.11}$$

and

$$\kappa = \frac{3}{1 + \delta\sqrt{\alpha^2 - \beta^2}}. \tag{D.12}$$

From Formula D.11 and Formula D.12, the parameters α and β can be determined by

$$\alpha = \sqrt{\left(\frac{3 - \kappa}{\kappa\delta}\right)^2 + \beta^2} \tag{D.13}$$

and

$$\beta = \pm\frac{\gamma(3 - \kappa)}{\kappa\delta\sqrt{3\kappa - \gamma^2}}. \tag{D.14}$$

Since α has to be larger than zero by definition, the negative solution can be omitted. Assuming the distribution is leptokurtic ($\kappa > 3$), Formula D.14 has a negative sign, whereas in the platykurtic case ($\kappa < 3$), the sign is positive. To obtain a hyperbolic distribution, λ has to be set to one. Note, that for symmetric distributions $\gamma = \beta = 0$ holds, and the formulas can be simplified further.

Acronyms

AAC Already Allocated Capacity. 24, 59

ACE Area Control Error. 54, 55, 60, 62–64, 73, 102–105, 107, 113–115, 129–131, 161, 191, 213

ACER Agency for the Co-operation of Energy Regulators. 20, 151

ADI Area Control Error Diversity Interchange. 61, 62, 161, 167

AGC Automatic Generation Control. 31, 33, 40, 41, 51, 53–56, 59, 61–64, 72–74, 77, 81, 83, 85, 89, 94, 98, 106, 108, 111, 113, 115, 126, 129–131, 133, 141, 145–147, 149, 171, 172, 178, 183, 188, 189, 191, 192, 212, 213

ASP Ancillary Service Provider. 45

AT Austria. 29, 91, 115, 119, 127, 136

ATC Available Transfer Capacity. 23–25, 53, 59, 175, 178

BA Bosnia and Herzegovina. 29, 91, 119, 127, 136

BE Belgium. 29, 91, 115, 119, 127, 136, 189

BG Bulgaria. 29, 91, 115, 119, 127, 136

BRP Balance Responsible Party. 2, 28, 30, 33, 38, 40–47, 78, 84, 87, 94–102, 104, 106, 109, 110, 114, 117, 121, 122, 124, 126, 128, 131, 132, 149, 169–179, 181, 183, 184, 191, 212–214

BSP Balancing Service Provider. 45, 191

CEA Canadian Electrical Association. 97

CH Switzerland. 29, 91, 115, 119, 127, 136, 189

CWE Central Western Europe. 25, 48

CY Cyprus. 29

CZ the Czech Republic. 29, 91, 115, 119, 127, 136, 189

DE Germany. 29, 91, 115, 119, 127, 136, 189

DK Denmark. 29

DSO Distribution System Operator. 1, 19, 20, 28, 45, 46, 102

EE Estonia. 29

EIA U.S. Energy Information Administration. 16, 166, 211

ENTSO-E European Network of Transmission System Operators for Electricity. 20, 26–29, 54, 58, 77, 78, 90, 91, 93, 94, 118, 128, 154–156, 162, 211, 212

ERIS Equipment Reliability Information System. 97

ES Spain. 29, 91, 115, 119, 127, 136, 189

ESS ENTSO-E Scheduling System. 28, 155

FCR Frequency Containment Reserves. 33, 44, 54–56, 58, 60, 61, 72, 74, 75, 78–82, 128, 187

FERC Federal Energy Regulatory Commission. 33

FI Finland. 29

FLH Full Load Hours. 84, 86, 92, 93

FR France. 29, 91, 115, 119, 127, 136, 189

FRM Flow Reliability Margin. 24

FRR Frequency Restoration Reserves. 33, 54–56, 58, 60–64, 76, 81, 82, 84–86, 97, 111, 113, 115, 117–121, 129, 136, 146, 183, 187, 191, 192, 213

GB Great Britain. 29

GR Greece. 29, 91, 115, 119, 127, 136

HR Croatia. 29, 91, 119, 127, 136, 189

HU Hungary. 29, 91, 115, 119, 127, 136

HVDC High-Voltage Direct Current. 12–14, 31, 39, 59, 60, 91, 154, 211, 212

IE Ireland. 29

IS Iceland. 29

ISO Independent System Operator. 19

IT Italy. 29, 91, 115, 119, 127, 136

ITO Independent Transmission Operator. 19

LFC Load-Frequency Control. 31, 89, 113, 114

LMP Locational Marginal Pricing. 53

LT Lithuania. 29

LTC Long-Term Contract. 23

LU Luxembourg. 29

LV Latvia. 29

ME Montenegro. 29, 91, 119, 127, 136

MEAS Mutual Emergency Assistance Service. 40, 62, 94, 137

MK Republic of Macedonia. 29, 91, 119, 127, 136

MSE Mean Squared Error. 121, 196, 213

MTTF Mean Time To Failure. 84, 86

MTTR Mean Time To Recover. 84, 86, 190

NL the Netherlands. 29, 91, 115, 119, 127, 136, 189

NO Norway. 29

NREAP National Renewable Action Plans. 27

NTC Net Transfer Capacity. 23–25, 59, 94

NWE North-Western Europe. 48

OpHB Operation Handbook. 20, 72, 74, 75, 78–80, 82, 83, 85, 128–131, 161, 162

OTC Over the Counter. 21, 27, 28, 38, 44, 96

PECD Pan-European Climate Database. 90, 107, 109

PL Poland. 29, 91, 115, 119, 127, 136, 189

PT Portugal. 29, 91, 119, 127, 136

PTDF Power Transfer Distribution Factor. 24

PTRs Physical Transmission Rights. 25

RAM Remaining Available Margin. 24, 59

RGCE Regional Group Continental Europe. 14, 20, 74, 76, 78–81, 93, 127–129, 133, 135, 137, 138, 141, 145, 147, 189–191, 213, 214, 217

RO Romania. 29, 91, 115, 119, 127, 136

RR Replacement Reserves. 33, 54–56, 60, 61, 84–86, 89, 95, 97, 108, 111, 113, 117–121, 124, 126–128, 146, 147, 172, 174, 183, 213

RS Republic of Serbia. 29, 91, 119, 127, 136

SE Sweden. 29

SHB Control block of Slovenia, Croatia, and Bosnia-Herzegovina. 73, 114, 115

SI Slovenia. 29, 91, 119, 127, 136

SK Slovakia. 29, 91, 115, 119, 127, 136

SMM Control block of Serbia, Montenegro, and the Republic of Macedonia. 73, 115

SO&AF Scenario Outlook and Adequacy Forecast. 26, 90

STLF Short-Term Load Forecasting. 98

TRM Transmission Reliability Margin. 23, 94, 134, 135, 137, 138

TSO Transmission System Operator. 1, 2, 4, 19, 20, 23–28, 30, 31, 33–35, 38–40, 42, 44–49, 52, 55, 57, 60, 61, 63, 71–73, 78, 85, 87, 93–98, 102, 106, 111, 113, 117, 120, 122, 124, 126, 129, 132–134, 136, 143, 145, 146, 148, 149, 153, 165, 169–172, 174, 175, 179, 181, 189, 191, 212

TTC Total Transfer Capacity. 23

TYNDP Ten-Year Network Development Plan. 26, 27

UCPTE Union pour la coordination de la production et du transport de l'électricité. 20, 75, 151, 166, 167

UCTE Union for the Co-ordination of Transmission of Electricity. 20, 74, 82, 83, 85, 93, 161, 162

VSTLF Very Short-Time Load Forecasts. 98

List of Figures

List of Tables