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Balancing Market Integration in Northern Europe

A 2030 Case Study

Eirik Schjander Torhaug

Master of Energy and Environmental Engineering
Submission date: June 2018
Supervisor: Hossein Farahmand, IEL

Norwegian University of Science and Technology
Department of Electric Power Engineering

Abstract

The future European power system is expected to incorporate a large share of renewable energy sources (RES). The intermittent nature of these sources will require a higher degree of flexible generation, thus increasing the need for reserve capacity providing balancing energy. In light of this the balancing market is predicted to play an increasingly important role in the future. European balancing markets are largely national markets, but because of the potential increase in system reliability and decrease in balancing costs associated with cross-border balancing, a fully integrated European balancing market is a target goal set out by the European Commission.

This thesis applies a flow-based Frequency Restoration Reserve (FRR) procurement model to a Northern European power system consisting of the Nordic countries, Germany, the Netherlands and Great Britain in a future 2030 scenario with a high share of renewables. The model clears a common day-ahead market, with FRR requirements as constraints. Transmission capacity is implicitly allocated with the same resolution as the clearing of the day-ahead market. A comparison between a non-integrated and fully integrated FRR procurement market focusing on the total system costs is conducted.

The results show that integration of FRR procurement markets leads to a decrease in total system costs of 4.8%, compared to the non-integrated case. This cost reduction is due to two factors. First, integration leads to the procurement of cheaper FRR resources. The availability of the cheap hydro power resources of the Nordic countries is the main reason for the reduction in procurement costs. Second, the increased flexibility in generation capacity due to integration also leads to less load shedding and unprovided FRR in the system, reducing costs substantially. The insufficiency of FRR capacity observed in Great Britain in the non-integrated case, and the significant exchange of FRR from the Nordic region to Great Britain in the integrated case indicates that Nordic hydro power can play an important role in providing the British system with reserves in the future.

Sammendrag

Det fremtidige europeiske kraftsystemet forventes å innlemme en stor andel fornybare energikilder. Den periodiske naturen til disse kildene vil kreve en høyere grad av fleksibel produksjon, og dermed øke behovet for reservekapasitet som gir balanseringsenergi. I lys av dette forventes balansemarkedet å spille en stadig viktigere rolle i fremtiden. Europeiske balansemarkeder er i idag i stor grad nasjonale markeder. Ved å integrere disse kan man potensielt øke systemets pålitelighet og redusere balansekostnader. Et integrert Europeisk balansemarked er derfor et mål fastsatt av EU-kommisjonen.

Denne oppgaven anvender en flytbasert FRR-anskaffelsesmodell til et Nord-Europeisk kraftsystem bestående av de Nordiske landene, Tyskland, Nederland og Storbritannia i et fremtidig 2030-scenario med høy grad av fornybar produksjon. Modellen klarerer et felles dayaheadmarked samtidig som reserver blir anskaffet. Overføringskapasitet blir allokert implisitt med samme tidsintervall som klareringen av day-aheadmarkedet. En sammenligning mellom et ikke-integrert og fullt integrert reservemarket med fokus på de totale driftskostnadene utføres.

Resultatene viser at integrering fører til en reduksjon av total systemkostnad på 4.8%, når man sammenligner med et ikke-integrert marked. Denne kostnadsreduksjonen skyldes to faktorer. For det første fører integrasjon til anskaffelse av billigere FRR-ressurser. Tilgjengeligheten til de nordiske landenes billige vannkraftressurser er hovedårsaken til reduksjonen i anskaffelseskostnader. For det andre fører den økte fleksibiliteten i generasjonskapasitet på grunn av integrasjon også til mindre rasjonering og uleverte reserver i systemet, noe som resulterer i kostnadsbesparelser. Den betydelige utvekslingen av FRR fra Norden til Storbritannia i det integrerte scenarioet tyder på at Nordisk vannkraft kan spille en viktig rolle i å forsyne det Britiske systemet med reserver i fremtiden.

Preface

This Master's thesis concludes my five year Master of Science (MSc) degree in Energy and Environmental Engineering at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU).

The thesis work has proved to be challenging at times, but first and foremost interesting and rewarding. I would like to extend my sincerest gratitude to my supervisor, associate Professor Hossein Farahmand, for always being available for discussions. This work has greatly benefited from his guidance and insight. I would also like to acknowledge Dr. Yonas Gebrekiros for valuable inputs and helpful advice.

Trondheim, June 2018

Eirik Schjander Torhaug

Abbreviations

AC	Alternating Current
aFRR	automatic Frequency Restoration Reserve
BM	Balancing Market
CACM	Capacity Allocation and Congestion Management
CNE	Critical Network Element
CWE	Central Western Europe
DAM	Day-Ahead Market
DC	Direct Current
EMHIRES	European Meteorological derived HIgh resolution Renewable Energy Source generation time series
ENTSO-E	European Network of Transmission System Operators for Electricity
FBMC	Flow Based Market Coupling
FCR	Frequency Containment Reserve
GSK	Generation Shift Key

IDM	Intra-day Market
IEM	Internal Electricity Market
mFRR	manual Frequency Restoration Reserve
MIP	Mixed Integer Problem
NP	Net Position
NTC	Net Transfer Capacity
PTDF	Power Transmission Distribution Factor
PTU	Program Time Unit
PV	Photo-Voltaic
PX	Power Exchange
RAM	Remaining Available Margin
RES	Renewable Energy Source
RR	Replacement Reserve
TEM	Target Electricity Model
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
WV	Water Value

Nomenclature

Sets

Z, A, T, R, Γ	Set of zones, balancing areas, time periods, balancing regions and planning periods
$Z_{a/r}$	Set of zones in balancing area a or balancing region r
G, G_r, G_B, G_z	Set of thermal, regulating, base-load thermal and thermal units within zone z
H, H_z	Set of hydro units and hydro units within zone z

Indices

z, y, v	Zone
a, b	Balancing areas
r, s	Balancing regions
g	Thermal units
h	Hydro units
τ	Planning period, $\in \{1, 365\}$
t	Time period, $\in \{1, 24\}$

Parameters

$MC_{z,g}$	Marginal cost of unit g in zone z (EUR/MWh)
$SC_{z,g}$	Startup cost of thermal unit g in zone z (EUR)
$PL_{z,\tau,t}$	Load level in zone z at time t (MWh/h)
$\overline{P}^{w/s}_{z,\tau,t}$	Maximum wind w or solar s generation capacity in zone z at time t (MWh/h)
$\overline{P}_{z,g/h}$	Maximum generation capacity of thermal unit g or hydro unit h in zone z (MW)
$\underline{P}_{z,g/h}$	Minimum generation capacity of thermal unit g or hydro unit h in zone z (MW)
$FC_{z,g}$	Fixed cost of thermal unit g in zone z when running (EUR)
$WV_{z,h,\tau}$	Water Value of reservoir associated with unit h in zone z at the end of τ (EUR/MWh)
VLL	Load shedding cost (EUR/MWh)
VLR	Reserve shedding cost (EUR/MW)
$\overline{Rr}^{\uparrow/\downarrow}_{a,\tau}$	Upward and downward FRR requirement in area a for planning period τ (MW)
$\psi_{z,y,v}$	PTDF value from zone z to zone y for unit injection in zone v
$\overline{P}^{AC/DC}_{z,y}$	HVAC or HVDC capacity between zones z and y (MW)
$\overline{R}^{\uparrow/\downarrow}_{z,g/h}$	Max possible FRR provision of thermal unit g or hydro unit h

Variables

$\delta_{z,g,\tau,t}$	Online status of thermal unit g in zone z at t, $\delta_{z,g,\tau,t} \in \{0, 1\}$
$u_{z,g,t,\tau}$	$= 1$ if thermal unit g in zone z i started up in time step t, 0 otherwise
$p_{z,g/h,\tau,t}$	Output of thermal unit g or hydro unit h in zone z at time t (MWh/h)
$p^{st/ns}_{z,h,\tau,t}$	Production from hydro unit h in zone z in planning period τ at t from storable inflow st or non-storable inflow ns (MWh/h)
$p^{s/w}_{z,\tau,t}$	Production from solar s or wind w in zone z in τ at t (MWh/h)
$p^{cur}_{z,\tau,t}$	Load curtailed in zone z at time t (MWh/h)
$p^{inj}_{z,\tau,t}$	Injection at zone z at a given time t (MWh/h)
$p^{AC/DC}_{z,y,\tau,t}$	Power flow on HVAC/HVDC line connecting zones z and y at t (positive $z \rightarrow y$) (MWh/h)
$r^{\uparrow/\downarrow}_{z,g/h,\tau,t}$	Procured upward/downward FRR from thermal unit g or hydro unit h in zone z in time period τ (MW)
$tr^{(AC/DC)\uparrow/\downarrow}_{z,y,\tau,t}$	Upward or downward FRR exchange on HVAC or HVDC line connecting zones z and y for planning period τ at time step t (positive value indicates export from z) (MW)
$Of_{z,h,\tau}$	Spillage in reservoir connected to hydro unit h, in zone z in planning period τ (MWh/h)
$rp^{\uparrow/\downarrow}_{z,\tau,t}$	Upward or downward FRR capacity procured in zone z in τ for time step t (MW)
$r^{cur,\uparrow/\downarrow}_{z,\tau,t}$	Amount of upward or downward FRR not provided in zone z in planning period τ at time step t (MW)

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Chapter 1 | Introduction

1.1 Background

A constant balance between supply and demand of electricity must always be maintained in an electric power system. In the European power system it is the responsibility of the Transmission System Operator (TSO) to ensure that this balance is always maintained within operating hours. They do so by procuring a sufficient amount of reserves prior to real-time, and activating these in the event of system imbalances.

With the rapid increase in electricity stemming from renewable energy sources (RES), the share of intermittent energy in the European power system is increasing, and is expected to continue to do so as countries rally to meet the European Commission's ambitious target of 27% of energy coming from RES by 2030 [1]. Consequently the amount of imbalances experienced in the power system is also expected to increase. The balancing market is therefore expected to play an increasingly important role in the future.

The European electricity markets are gradually integrating. This development is lead by the ongoing implementation of the European Commission's Target Electricity Model (TEM). The ultimate goal of the model is to create a fully integrated European electricity market, often referred to as the Internal Electricity Market (IEM). An integrated European electricity market should in theory increase competition, and lead to cost reductions and/or an increase in productivity through innovation [2]. Integration also provides increased flexibility with regards to the use of generation and network capacities, leading to a more efficient use of assets, which in turn should lead to lower electricity prices for the consumer [2].

Currently European balancing markets are largely national markets. This means, with some exceptions, that each control area is responsible for the dimensioning, procurement and activation of its reserves. In light of the implementation of the TEM, and the increasing amount of expected imbalances due to RES integration, balancing market integration is garnering attention in academia and in the industry [3]. Balancing market integration enables the TSOs to procure and/or activate reserves in other control areas. This increased coordination means that the amount of reserves needed in the system can be reduced. Furthermore the cost associated with procuring and activating reserves can be decreased due to the availability of cheaper reserves.

It is important to distinguish between the reserve market, which deals with the procurement of reserves prior to operation hours, and the balancing energy market, which deals with the activation of balancing energy in real-time. An important topic which is underexposed in existing literature is the impact of integrating these markets in a future power system with large-scale RES integration. This thesis investigates the effects of integrating FRR procurement markets in a Northern European system consisting of the Nordic countries, Germany, the Netherlands and Great Britain in a hypothetical 2030 scenario with large-scale integration of RES. The analysis is conducted through the use of an optimization model which implicitly procures reserves simultaneously with the day ahead clearing. The model also implicitly accounts for cross-border transmission capacity, by co-optimizing the transmission capacity used for energy transfer and for the exchange of reserves.

1.2 Scope

This thesis investigates the impact of integrating Northern European Frequency Restoration Reserve (FRR) procurement markets in a 2030 scenario with large-scale integration of RES. The case study considered consists of the Nordic, German, Dutch and British power systems. More specifically the thesis investigates potential cost benefits associated with a more efficient and flexible utilization of generation capacity. A similar study was conducted by Farahmand et.al in [4], but their case study does not include FRR procurement in the British power system, nor does the system fully reflect the large-scale integration of RES in 2030, as for example PV production is not considered. The main contribution of this thesis is therefore an analysis of the effects of integrating Northern European FRR procurement markets in a system that includes Great Britain and reflects a potential 2030 state with a large share of RES.

1.3 Report Structure

This thesis is structured in the following way:

Chapter 1 - *Introduction*, provides a brief background, motivation and scope of the thesis work.

Chapter 2 - *Background*, gives a non-exhaustive introduction to how the electricity sector is operated, the concept of power system balancing, and gives an overview of the current balancing market design in Europe. An introduction to the concept of market coupling is then provided. Finally an overview of current balancing market integration initiatives and academic literature concerning this topic is presented and discussed.

Chapter 3 - *Methodology*, provides a description of the optimization model used in this thesis. Furthermore the case study considered is described, and the data collection process is elaborated upon. Assumptions and simplifications made are also explained.

Chapter 4 - *Results and Discussion*, presents and discusses the results obtained from applying the model to the case study. Limitations and sources of error of the work conducted are also discussed.

Chapter 5 - *Conclusion and Further Work*, sums up the results presented in Chapter 4, and attempts to answer the research question posed in the scope. Finally further work is proposed.

Chapter 2 | Background

This chapter provides the necessary background needed to understand the concepts touched upon in this thesis. Section 2.1 gives a brief introduction to the organization and operation of the European power system, and outlines the main workings of European electricity markets. Section 2.2 provides a non-exhaustive introduction to the concept of system balancing. Section 2.3 describes the balancing market mechanism. Section 2.4 introduces the reader to the concept of market coupling, and outlines current and future efforts to integrate individual markets, with the focus being on balancing markets. Section 2.4 also provides an overview of the academic literature concerning balancing market integration.

2.1 Power System Organization and Operation

Historically speaking the European electricity sector has been dominated by vertically integrated utility companies or government institutions which owned and operated production, transmission and distribution facilities [5]. Following the deregulation of the sector in the 1990s the industry was separated into individual generation, transmission and distribution companies. Figure 2.1 shows the general structure of a deregulated electricity sector.

In Europe the transmission system is generally owned and operated by the Transmission System Operator (TSO), which is responsible for maintaining the system stability at all times. Generation companies are usually owners of generation units and represent the supply side in the electricity market. Distribution companies deliver electricity to consumers, and represent the demand side in the electricity market. As seen from figure 2.1 trade is done between all

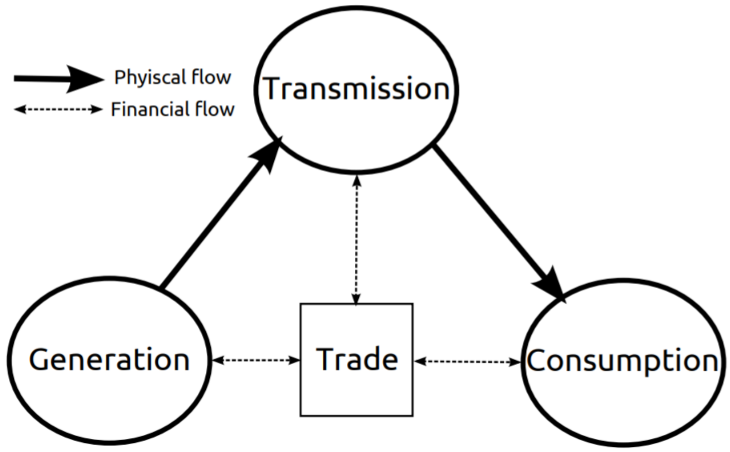


Figure 2.1: General structure of a deregulated electricity sector [5].

entities in the sector. This trade is conducted through several integrated and consecutive markets. These include the future/forward market, the day-ahead market (DAM), the intraday market (IDM), and the balancing market (BM). The balancing market encompasses both the reserve market and the balancing energy market. The trade in these markets are made through various forms of exchanges. These exchanges pools buyers and sellers together, and offer transparent pricing [6]. In addition to the trade made through exchanges, bilateral trading, also referred to as over-the-counter (OTC) trading, offers the possibility of direct trading between market participants, without the use of a trusted third party. The time horizon of the various markets is depicted in figure 2.2.

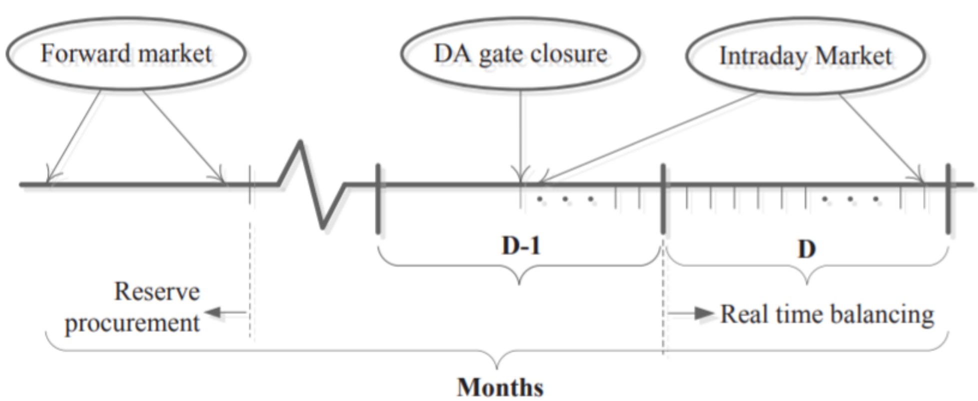


Figure 2.2: Illustration of the consecutive electricity markets [7].

In the forward market standardized long term contracts are traded through an exchange. These contracts do not involve the physical delivery of electricity, but are instruments market players can use to hedge the price risk they face as a result of the stochastic nature of electricity prices [5].

The day-ahead market enables the trade of short term contracts. It opens the day before physical delivery, and is the main platform for trade of electricity in European countries [5]. Day-ahead markets are operated by power exchanges (PX), which facilitate the purchase and selling of electricity through binding contracts. Bids are aggregated into supply and demand curves and the intersection between the two determines the spot price of the system, which functions as a reference price for the whole electricity market [8]. The market clears the day before delivery, and the price is thus for the following day.

As bids in the DAM are submitted for time periods several hours after market clearing, there are several uncertain factors that could affect the portfolio of market players before physical delivery. These factors include the unpredictability of the weather, breakdown of production units, as well as outages in the transmission system [8]. Consequently imbalances between production and consumption schedules and the volume committed in the DAM do occur. The intra-day market gives the market participants the possibility to continuously adjust any imbalances up until the hour of operation. Bids in the IDM are submitted to the PX anonymously, and prices are set based on a pay-as-bid, first come, first-served basis [8].

If market participants are not able to balance their positions in a sufficient manor in the IDM, the TSO has to step in to ensure that the system balance is maintained. To be able to do so they procure a sufficient amount of reserve capacity that can be called upon if needed. This is done well before real-time through a market mechanism called the reserve market. In the event of imbalances it is also the responsibility of the TSO to activate enough balancing energy and remunerate the generator supplying this. This is done through a market mechanism referred to as the balancing energy market. The notion of balancing control and the organization and operation of the balancing market is elaborated upon in the following sections.

2.2 Balancing the System

When a power system experiences a power imbalance, the stored rotational kinetic energy in turbines is released in response to the imbalance energy, resulting in a reduction of system frequency [9]. Major deviations from the system frequency may jeopardize the stable operation of the system, and could potentially lead to partial or complete blackouts [5]. Maintaining the nominal system frequency in a power system is therefore of great importance.

In order to counteract deviations from the operating frequency resulting from imbalances between load and supply, a power system needs a sufficient amount of reserve capacity. Reserves can be classified as long-term or short-term. The concept of long-term reserves is related to the adequacy of reserve capacity resources and infrastructure within a power system over a longer time period, i.e years. The concept of short-term reserves is related to operational reserves and concerns the adequacy in the time frame of seconds or minutes. Reserves can be delivered by conventional power plants, energy storage units, demand response or by curtailment of renewable energy [10]. This thesis only deals with short-term reserves delivered by conventional power plants.

To be able to handle imbalances between load and supply within operating hours, the TSO procures various operational reserve products ahead of operation time from Balancing Service Providers (BSP). These products are separated by their response time and activation time. In Europe one can distinguish between three different reserve products, as described by ENTSO-E [11].

- Frequency Containment Reserves (FCR). FCR are fast reserves that are automatically activated within seconds, and are put in place to contain the system frequency within a secure range of the operating frequency, i.e 50 Hz in Europe. The activation of FCR is done jointly within a synchronous area. FCR are also know as primary reserves.

- Frequency Restoration Reserves (FRR). FRR are activated within a timeframe of seconds to minutes, and are used to alleviate the used FCR as well as restore the frequency back to its operating point. This is done by the affected TSO, i.e the TSO of the control area that experiences the disturbance. FRR can be further divided into automatic Frequency Restoration reserves (aFRR) and manual Frequency Restoration Reserves (mFRR). aFRR are activated more quickly than manual mFRR. aFRR are also know as secondary reserves, while mFRR are also known as tertiary reserves.

- Replacement Reserves (RR). RR are activated in the case of major disturbances, and replaces and/or supports the already activated FRR. The activation of RR is also done by the affected TSO. It should be noted that not all control areas, e.g the Nordic countries, operate with Restoration Reserves. RR are also known as tertiary reserves.

Figure 2.3 shows the consecutive activation of the different types of reserves following an imbalance.

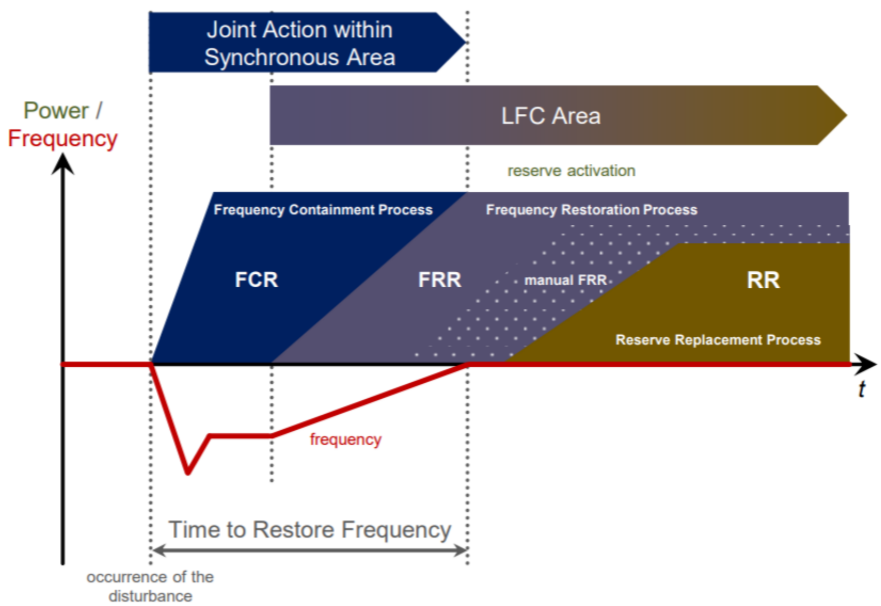


Figure 2.3: Reserve activation timeline following a disturbance [11]

It is important to make the distinction between upward and downward reserves. Upward reserves are used to handle negative system imbalances, i.e undersupply or overconsumption, which causes a frequency drop. Downward reserves, on the other hand, are used to handle positive system imbalances, i.e oversupply or underconsumption causing a frequency rise. The TSO needs to procure a sufficient amount of the different reserve categories in both directions in order to ensure operational stability at all times.

2.3 The Balancing Market

This section is meant to serve as a non-exhaustive description of the general structure of European balancing markets. For a more in-depth description of balancing market arrangements of individual countries, the reader is referred to [9] and [12].

Balancing markets in Europe can be divided into three distinct and consecutive phases [3]. The first phase is referred to as the dimensioning phase and occurs months or years prior to operation hours. In this phase each TSO determines the amount of reserves needed in its own control area, for each reserve category[1]. The dimensioning follows rules stipulated in the European Commission's Guideline on Electricity Transmission System Operation [13]. The dimensioning process is currently largely based on deterministic or simple probabilistic models which assume that RES forecast errors follow a Gaussian distribution [14]. With the increase of RES in the power system the need for dynamic reserve sizing will increase. This is however outside of the scope of this thesis, and will not be discussed further.

Following the dimensioning phase, each TSO procures enough reserve capacity to cover the reserve requirement in its control area from Balance Service Providers (BSPs), through a market mechanism referred to as the reserve market or capacity market. This is usually done well in advance of real-time (i.e days to months). BSPs submit their bids for capacity to the TSO, and if their bid is accepted, the capacity submitted may not be utilized for power production, unless called upon by the TSO. In return the BSPs receive a remuneration which reflects the opportunity cost experienced as a result of not being able to participate in the other electricity markets, i.e day-ahead and intra-day markets [3].

Third, the TSO activates reserves in real-time to counteract imbalances, in what is known as the deployment or activation phase [3]. Planned production and/or consumption and exchange between other BRPs is submitted to the TSO by each BRP before the real-time dispatch. In the event of deviations between submitted schedule and actual delivery of electricity, the TSO penalizes the responsible BRP, and remunerates the BSP providing the

[1]The exception is Frequency Containment Reserves which is determined on a European level by ENTSO-E for each synchronous area, and allocated to the individual TSOs [3]

balancing energy, through a mechanism referred to as the imbalance settlement mechanism. In the imbalance settlement mechanism, an imbalance price and a balance energy price is calculated for each imbalance time unit. The price calculation is based on the activated bids in the balancing energy market, but varies substantially from market to market [9]. Bids to deliver balancing energy are submitted to the TSO, and accepted based on financial merit order [15]. Accepted downward bids decrease their generation, while accepted upward bids increase their generation. In return they receive the balance energy price. The prices should create financial incentives for the BSPs to submit balancing bids and BRPs to balance their production portfolios prior to real-time [4]. The interaction between market participants in the balancing market is shown in figure 2.4.

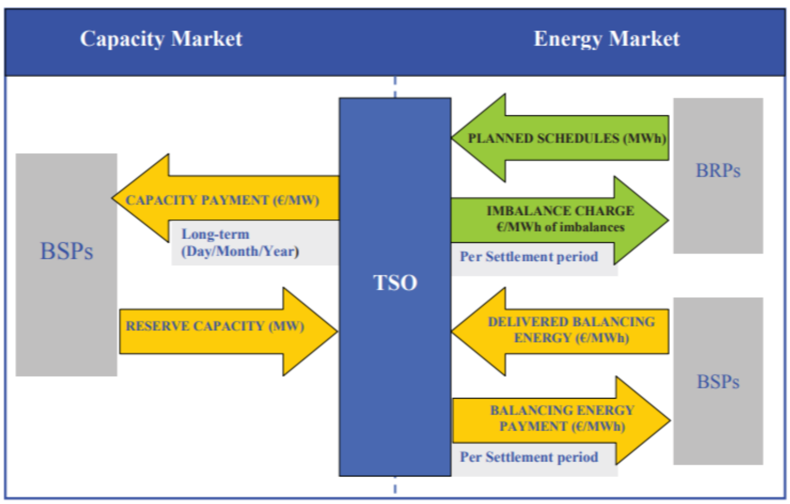


Figure 2.4: Interaction between market participants in the balancing market [9]

As mentioned the procurement of reserves is done through long-term contracts. The procurement of reserves is therefore done completely separate from the day-ahead market, increasing the risk of economic efficiency losses [4]. A theoretically more optimal solution would be to procure reserve capacity while simultaneously clearing the day-ahead market [4]. This could be realized by allowing BRPs to submit bids for the capacity and day-ahead market at the same time. The model used in this thesis uses this type of modelling approach.

2.4 European Electricity Market Integration

2.4.1 Market Coupling

Central to the completion of the IEM is the coupling of individual national markets. Market coupling refers to the optimized allocation of cross-border capacity based on the coordinated calculation of prices and flows between countries [16]. There are currently two market coupling methodologies used in the European electricity system; Flow Based Market Coupling (FBMC) and Net Transfer Capacity (NTC)-based market coupling[2].

A fundamental problem in the allocation of cross-border capacity is the inherent difference between commercial power flows and physical power flows. Commercial flows correspond to the exchange programs scheduled between market players and disregards the physical properties of the grid, while the actual physical flows in the network follow Kirchoff's laws and are distributed on all parallel paths connecting two nodes. As a result, physical flows may deviate quite significantly from commercial flows. This is illustrated in figure 2.5.

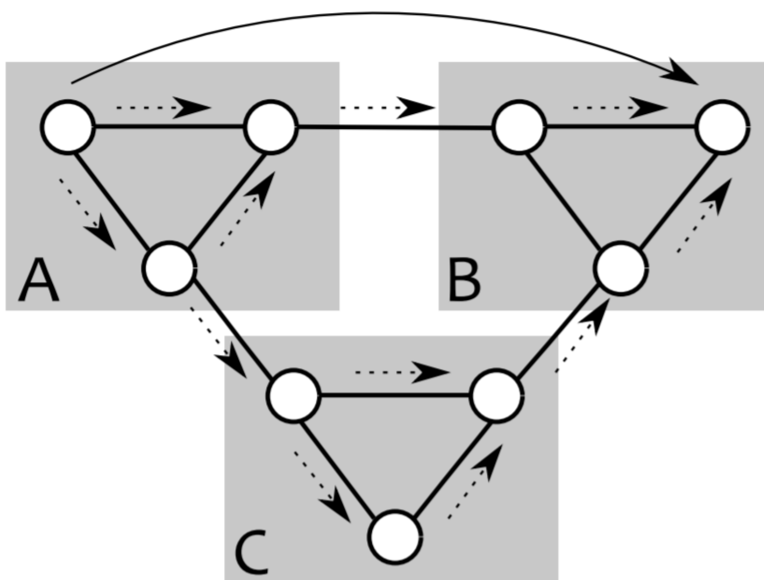


Figure 2.5: Illustration showing how a commercial flow (solid arrow) between a node in area A and a node in area B may translate into physical flows (dashed arrows) [17].

[2]NTC-based market coupling is also known as Available Transfer Capacity (ATC)-based market coupling

Both internal and cross-border commercial flows can lead to physical flows within neighbouring areas. These flows are referred to as loop flows and transit flows, and pose a challenge in the allocation of cross-border capacity. Loop flows are defined as physical cross-border flows that result from an internal commercial flow (i.e both source and sink are in the same zone). Transit flows are defined as physical cross-border flows resulting from a cross-border commercial flow (i.e source and sink are in different zones). In the NTC approach these flows are not taken into account in the market clearing, instead it is the responsibility of the TSO to deal with them. In order to cope with flows that originate from outside their own control area, the TSO has to allocate cross-border capacity prior to the market clearing. Because the allocation takes place before the market clearing, the capacity allocated is based on forecasted loop and transit flows. As the prediction of loop flows and transit flows is difficult, especially in highly meshed grids [18], the capacity allocation may lead to a loss of efficiency if the capacity allocated is not fully utilized.

In FBMC the flows on every Critical Network Element (CNE) are taken into account in the market clearing. This is done by using a linearized grid model in the form of a Power Transfer Distribution Factor (PTDF) matrix. The PTDF matrix provides the relationship between the net position of a zone (or node) and the flows on critical lines. The flow-based transmission constraints used by the market clearing algorithm can be formulated as seen in equation 2.1 for a zonal market clearing:

$$\sum_{z \in N} PTDF_{z,CNE} \cdot NP_z \leq RAM_{CNE} \tag{2.1}$$

Which ensures that the power flow on a CNE resulting from changes in the net position (NP) of zones in a system does not exceed the CNE's Remaining Available Margin (RAM). The RAM is the maximum line capacity that can be used by the market clearing algorithm. Because the transmission capacities are provided together with a simplified grid model, the market clearing algorithm is able to implicitly consider loop flows, transit flows, as well as congestions. As a result TSOs do not have to prioritize and allocate cross-border capacity ex ante the market clearing, but can instead leave this to the market clearing algorithm. The total security of supply domain is therefore available to the market clearing algorithm [19]. This means that the flow-based solution domain is likely to be larger than the NTC domain [17]. This is illustrated in figure 2.6. Each flow based boundary seen in figure 2.6 relates to a critical line. Because the objective function is to maximize the socio-economic surplus for both approaches, and the solution domain is larger for the flow-based method, the flow-based method should in theory yield better results.

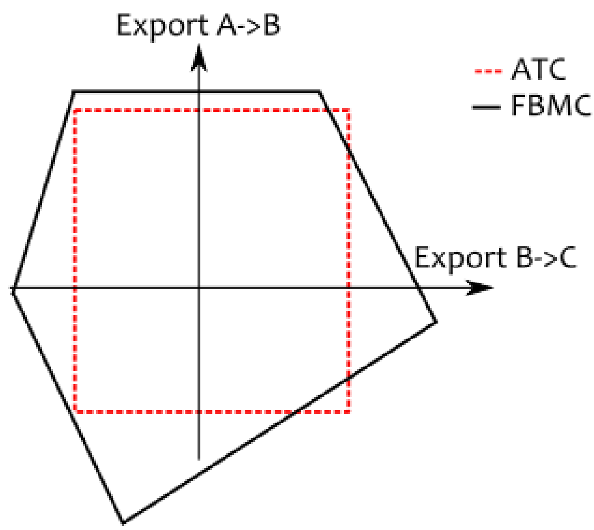


Figure 2.6: Comparison between the NTC trading domain and the flow based trading domain [17]

Though the predominant method used in the European system is the NTC method, the FBMC method is gaining traction. In the Central Western European (CWE) region[3] FBMC has been in operation in the day-ahead market since May 2015. The implementation has shown promising results, indicating that FBMC leads to an increase in economic welfare and price convergence between zones [19]. Flow based market coupling is also considered to be the preferred methodology for allocation of cross-border capacity in the Network Code on Capacity Calculation and Congestion Management (NC CACM) prepared by ENTSO-E, unless there is no added value to apply the FB approach [18].

[3]The CWE region covers Belgium, Luxembourg, France, Germany and the Netherlands

The PTDF Matrix

A key parameter in flow based market coupling is the PTDF matrix. Essentially what a PTDF expresses is how a change in the net position of a node or area affects the power flow on a given line in the system. An expression for PTDF can be derived from the standard DC power flow equation seen in equation 2.2, which provides a linear relationship between the voltage angles δ and power flows in the system. B_{ik} is the susceptance between node i and k.

$$P_{ik} = B_{ik}(\delta_i - \delta_k) \tag{2.2}$$

If we consider a change in power flow on line ik equation 2.2 becomes:

$$\Delta P_{ik} = B_{ik}(\Delta\delta_i - \Delta\delta_k) = B_{ik}\Delta P_n(Z'_{bus,in} - Z'_{bus,kn}) \tag{2.3}$$

The prime here indicates that the impedance values have been augmented as a result of the inclusion of a reference point. By setting ΔP_n equal to unity one can obtain an expression for the PTDF of line ik as a result of a change in net position of node n:

$$PTDF_{ik,n} = B_{ik}(Z'_{bus,in} - Z'_{bus,kn}) \tag{2.4}$$

If one calculates the PTDF values for all lines and nodes one can obtain the PTDF matrix, which gives a linear relationship between injections at given nodes and the accompanying flows on the lines in a power system. As such a PTDF matrix can be considered to be simplified grid model.

Though a nodal representation of the power system through the use of nodal PTDFs is possible, and does in fact give the most accurate representation, it requires the handling of a substantial amount of data, and is thus often computationally demanding [20]. Besides, the European Target Model proposed by the European Commission is based on a zonal market clearing [17]. There is therefore a need to aggregate nodal PTDFs to corresponding zonal PTDFs. A zonal PTDF expresses the relationship between a change in the aggregated net position of a zone and the flow on critical network elements (CNE). In order to accurately account for the effect each individual node has on the net position of the zone it is situated in, Generation Shift Keys (GSK) are used. An expression for the aggregation of PTDFs through the use GSKs is showed in equation 2.5. $PTDF_{ik,A}$ here denotes the aggregated zonal PTDF.

$$PTDF_{ik,A} = \sum_{n} GSK_n PTDF_{ik,n} \tag{2.5}$$

Where

$$\sum_{n} GSK_n = 1 \tag{2.6}$$

Because the market clearing algorithm relies on the zonal PTDF matrix when it makes unit commitment and capacity allocation decisions, the quality of the grid representation obtained through the use of GSKs heavily influences the market outcome. Correct weighting of each node is therefore of great importance. Some weighting strategies include equal weighting of each node (pro rata), weighting based on generation, weighting based on net power injection, and weighting based on remaining capacity in generation [21].

2.4.2 Day-ahead and Intraday Market Integration

Day-ahead market coupling has gradually been introduced to different regions in the European power system, starting with the Tri-lateral day-ahead market coupling between France, Belgium and the Netherlands between 2006 and 2010. This eventually evolved into the Central Western European (CWE) market coupling in 2010. In parallel the CWE region has been volume coupled with the Nordic region since the inception of the CWE market coupling. In 2014 the coupling of the North Western European (NWE) region [4] through the use

[4]NWE includes the CWE region, the Nordic countries, Great Britain and the Baltic states

of the pan-European marked coupling algorithm EUPHEMIA[5], marked the start of the Price Coupling of Regions (PCR) [16]. Since then Italy, Spain and Portugal have joined, resulting in a multi-regional market coupling covering 19 countries, standing for approximately 85 % of European power consumption [16].

In addition to the ongoing integration of day-ahead markets, a multinational European intraday platform called XBID is currently being developed, and is expected to launch in the second quarter of 2018 [22]. The platform will enable the continuous matching of orders submitted in one country with similar orders submitted in other countries. The initiative is helmed by the power exchanges EPEX SPOT, GME, Nord Pool and OMIE, as well as 11 European TSOs.

2.4.3 Balancing Market Integration

Balancing markets in Europe are currently largely uncoordinated, as reserve procurement and balancing energy activation is mainly confined to national markets. Though the national markets have a similar fundamental market design, there exists major differences in the individual national rules, which prevents the full integration of balancing markets. Some design parameters which vary are the program time unit (PTU), product definitions, gate closure times, procurement and pricing mechanisms, bid requirements, imbalance pricing and frequency of imbalance settlement [23]. The degree of convergence of these parameters needed in order to effectively harmonize individual balancing markets depends on the cross-border balancing arrangements. ENTSO-E lays out four possible cross-border balancing arrangements in [24] and [11], which are listed below.

- *Exchange of reserves* is the procurement of reserves by a TSO in another control area than its own. This means that the most cost-efficient reserves can be procured, regardless of where the reserve is located. Exchange of reserves impacts the procurement phase and activation phase.
- *Reserve sharing* is the procurement of the same reserve by two different TSOs. As a

[5]EUPHEMIA stands for: EU + Pan-european Hybrid Electricity Market Integration Algorithm.

result, the total amount of reserve procured is decreased. In this arrangement both TSOs are relying on the same reserves in the event of imbalances. Only reserves that are unlikely to be activated simultaneously by the two TSOs should therefore be eligible for reserve sharing. Reserve sharing affects the procurement and activation phase.

- *Imbalance netting* is the cancellation of opposite imbalances in adjacent areas. This reduces the amount of balancing energy that has to be provided, resulting in cost reductions. The implementation of this arrangement does not require any change in balancing market design [12]. Imbalance netting affects the activation phase.

- *Common merit order list* refers to the aggregation of balancing energy bids from neighbouring TSOs to form a common merit order list. BSPs submit bids to their respective TSO, which in turn creates a local merit order and submits this to a regional TSO which creates the common merit order list. A central algorithm then activates the most cost-efficient reserves in real-time, regardless of their geographic location. This arrangement has an impact on the activation phase.

Exchange of reserves and reserve sharing can either be implemented with a TSO-TSO model, where TSOs trade with each other, or with a BSP-TSO model, where BSPs are allowed to trade directly with another TSO than its connecting TSO. Another balancing market arrangement called additional voluntary pool, or TSO-TSO trading without common merit order list, is also proposed in literature [25]. ENTSO-E states in [24] that the final target solution for a future European-wide balancing market should be based on a TSO-TSO model *with* a common merit order list.

The potential benefits of balancing market integration are summarized by Baldursson et al. in [15]. The mentioned benefits include a more efficient utilization of generation capacity, a reduction in necessary reserve capacity, a higher level of reliability, a level playing field as a result of standardization of rules and products, and lastly increased competition as a result of improved market liquidity. The analysis conducted in this thesis focuses on the cost benefits associated with a more efficient utilization of generation, i.e the reduction in cost as a result of procuring the most cost efficient reserves in the system.

A prerequisite to the implementation of any of the aforementioned cross-border balancing arrangements, with the exception of imbalance netting, is a coordinated allocation of cross-border transmission capacity for the exchange of balancing services. As the amount of capacity allocated for balancing services decreases the amount available for energy exchange in the day-ahead market, the allocation process should optimize the share of capacity allocated between the two. This is illustrated in figure 2.7.

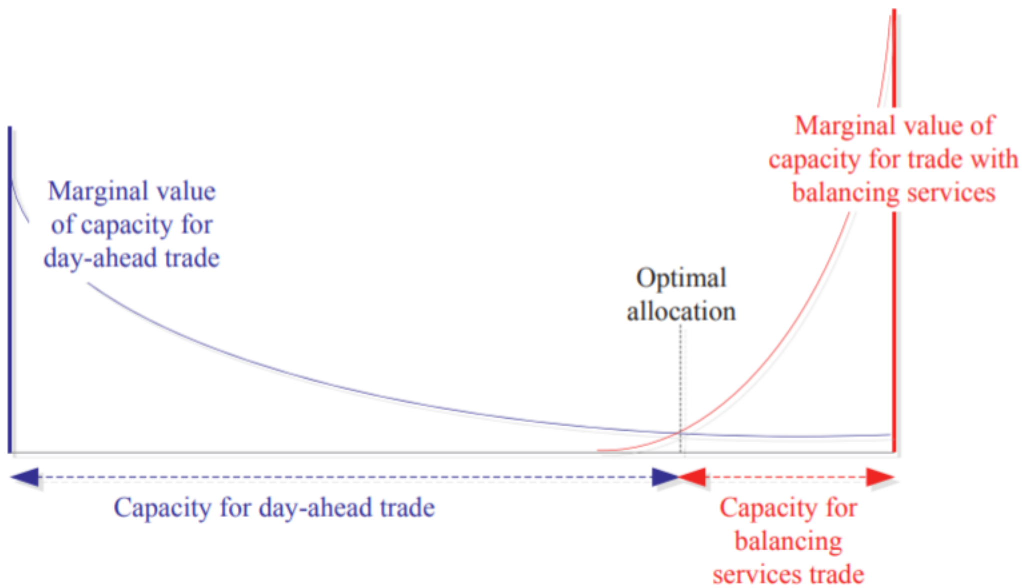


Figure 2.7: Optimal allocation of cross-border capacity [26].

ENTSO-E presents three methods to reserve cross-zonal capacity in [24]. These are listed below in order of complexity.

- *Reservation based on economic efficiency analysis.* In this method an analysis is conducted by the TSO, which compares the forecasted market value of balancing services and the forecasted market value for exchange of energy (i.e DAM prices). With this analysis as basis, the TSO reserves cross-border capacity before the transmission capacity auction takes place between market participants.

- *Market-based reservation.* This process is similar to the reservation based on economic efficiency, except for the fact that the market value of balancing services is based on actual submitted reserve bids, instead of forecasted ones.

- *Co-optimization process.* In the co-optimization process, the TSO participates in an ordinary transmission capacity auction together with other market participants to reserve cross-border capacity, while simultaneously procuring reserve capacity. The auction can either be implicit, i.e the optimal transmission capacity reservation for reserve exchange is implicitly obtained from clearing the DAM and reserve market simultaneously, or explicit where market participants bid on the cross zonal capacity based on the expected market value.

Without one of these arrangements in place, the activation of reserves procured in other control areas and subsequent exchange of balancing energy would not be possible due to insufficient cross-border transmission capacity on interconnections in real-time.

2.4.4 Examples of Cross-border Balancing

Multinational balancing markets are still in its early stages. There are however some examples of successful cooperation across borders. A coordinated dimensioning and partially coordinated procurement of FCR is in place between France, Austria, Belgium, Germany, Switzerland and the Netherlands[3]. The FCR cooperation currently operates with weekly auctions with one symmetric product, and is organized with a TSO-TSO model where the reserves are procured through a common merit order list [27]. In addition to this, the reserve sharing of 300 MW of mFRR is currently in place between the Belgian (Elia), Dutch (TenneT NL) and one of the German (TenneT DE) TSOs [3]. Furthermore a cooperation through a joint market for mFRR called the Regulating Power Market (RPM) is in place in the Nordic countries (Denmark, Finland, Norway and Sweden) [15]. The Nordic TSOs are also currently developing a common market for aFRR [28]. A cross-border energy imbalance market has also been successfully established between CAISO and PacifiCorp in the United States since November 2014 [15].

In addition to the aforementioned initiatives, ENTSO-E is reviewing several pilot projects which deals with cross-border procurement of reserves and activation of balancing energy. Firstly, the International Grid Control Cooperation (IGCC) is a regional imbalance netting project between 11 TSOs from 8 countries[6]. The implementation of the process is based on the fact that each individual TSO reports their aFRR demand to an aFRR optimization system, which coordinates the activation of aFRR, thus avoiding counter activation, leading to an optimized use of aFRR resources [29]. Secondly, the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is a regional project between several European TSOs, aiming to design, implement and operate a coordinated platform for aFRR. Third, an initiative with the goal of creating a European platform for the exchange of balancing energy from mFRR, called the Manually Activated Reserves Initiative (MARI) is currently underway. 26 European TSOs are currently involved in the cooperation [30]. Lastly the Trans European Replacement Reserves Exchange (TERRE) project is an initiative which aims to build a European platform for RR exchange. The project currently consists of 11 TSOs, and has launched the implementation phase [31].

2.4.5 Literature Study on Balancing Market Integration

There are several examples of literature investigating the benefits of integrating balancing markets, from both qualitative and quantitative perspectives. Meeus et al. [32] were among the first to argue that coordination between TSOs in balancing markets is a prerequisite to a well-functioning European electricity market. In [25], Doorman and Van der Veen define six multinational balancing market designs, and evaluate the benefits using a set of technical and economic performance criterias. They conclude that all design options lead to an overall improvement in balancing market performance, but with varying degree of improvement.

Vandezande et al. [33] use a statistical analysis based on real data to estimate the effect of cross-border balancing between the Netherlands and Belgium. They find cost reductions in the range of 29% to 44 % depending on the amount of available transmission capacity following the clearing of the day-ahead market. Farahmand and Doorman [34] analyze the benefits of integrating balancing markets in Northern Europe through the use of a fundamen-

[6] Austria, Belgium, Czech Republic, Denmark, France, Germany, the Netherlands and Switzerland

tal market model based on DC power flow. In their work, the day ahead market is modelled with simultaneous reserve procurement, and the exchange of balancing energy market is modelled as a real time power dispatch, which is based on the day-ahead market clearing results. They find that market integration leads to moderate cost savings in the reserve procurement market, but considerable savings in the balancing energy market. The cost savings are attributed to imbalance netting and the activation of cheaper reserves. In [3] Van den Bergh et al. use an NTC-based market model to investigate several scenarios with varying degrees of cross-border coordination in the procurement and activation phase in the Central Western European (CWE) electricity system. They find that cross-border balancing markets leads to a more cost-efficient and secure system. The case study conducted indicates a decrease in operational generation costs of 0.5% to 2.1% depending on the level of cross-border coordination. Jaehnert et al. [35] analyze a integrated Northern European regulating power market through the use of a fundamental market model. Their results indicate that the possibility of exchanging reserves and balancing energy between the Nordic region and continental Europe leads to a substantial socio-economic benefit. The observed cost of reserve procurement is decreased by EUR 60-80 million per year, while the the reduction in balancing energy costs amounts to EUR 40-50 million per year, when compared to the non-integrated case.

In [21], Gebrekiros et al. use a flow-based model to investigate the impact of market design on cross-border FRR procurement costs in Northern Europe by applying a sequential and implicit market clearance to a common day-ahead market with optimal reservation of cross-border transmission capacity. They find that implicit market clearance results in the lowest costs. In [15] Baldursson et al. develop a stylized model of cross-border balancing, where they distinguish between three forms of cooperation, namely autarky (no trade or exchange between zones), reserve exchange and reserve sharing. Based on actual price and aFRR procurement market data from Belgium, France, Germany, the Netherlands, Portugal and Spain, they find that reserve exchange leads to a decrease in reserve procurement cost of EUR 160 million per year, and a decrease of EUR 500 million per year when allowing reserve sharing.

Even though the literature on balancing market integration is quite extensive, the analyses conducted are mainly based on the current state of the electricity system. There are some exceptions, most notably Farahmand et al. [4] analyzed the impact of integrating balancing markets in a Northern Europe system reflecting a 2030 scenario with large scale integration of wind power. The modelling approach used is similar to the one outlined in [34]. Their results show a reduction in procurement cost of 72%, as well as a reduction in balancing energy cost of 30%, compared to the non-integrated case, emphasizing the benefits of balancing market integration for the handling of variable production. MacDonald [36] looked at the impact of integrating balancing energy markets and sharing of reserves on hypothetical scenarios towards 2030 for the future European power system through the use of a dynamic system investment model. Their results demonstrate significant benefits, with cost savings in the order of 3 billion EUR/year, and a reduction of up to 40 percent in reserve requirements. The benefits cited increase with the amount of wind penetration. Aigner et al. [37] looked at the benefits of integrating balancing markets in Northern Europe, with a high penetration of wind power production. They considered several scenarios within the years 2010, 2015 and 2020 and found significant cost reductions. For the 2020 scenario the procurement costs were reduced by 30% compared to the non-integrated case, while balancing energy costs decreased by 50%.

To summarize, the benefits of multi-national balancing markets can be quantified either through the use of simulation models of the electricity system or through the use of statistical analysis. The first approach is used in this thesis. Existing literature indicates that there is substantial cost benefits from coordinating both reserve procurement and activation across borders. Furthermore the cost savings seem to be somewhat correlated with amount of RES in the system considered.

An important issue that is underexposed in literature is the benefits associated with cross-border reserve procurement in a future European system with large scale RES integration. Though [37] and [4] do investigate this for scenarios reflecting the 2020 and 2030 state of the Northern European system respectively, they do not account for the large increase in PV production which is expected in Northern Europe, especially in Germany. Furthermore their case studies do not consider the British power system. With the commissioning of two

HVDC cables connecting Norway and Great Britain, a case study considering a Northern European system which includes Great Britain is highly relevant.

With this as a starting point, this thesis seeks to investigate the impact of reserve market integration on the total system costs and the spatial distribution of reserves by applying a fundamental flow-based FRR procurement market model to a hypothetical 2030 power system with high RES share, consisting of Great Britain, the Nordic countries, Germany and the Netherlands.

Chapter 3 | Methodology

3.1 Model Description

The model used in this thesis was developed by Yonas Gebrekiros as part of his doctoral thesis investigating the integration of Northern European balancing markets under different market designs [12]. It is a flow-based unit commitment model based on zonal PTDFs, that clears a common Northern European day-ahead market with upward and downward FRR requirements given as constraints to the optimization problem. The procurement of reserves is therefore implicitly done simultaneously with the day-ahead market clearing. Optimal transmission capacity reservation for cross-border FRR exchange is also implicitly obtained from the cost minimization problem. The resolution of the FRR procurement and allocation of cross-border capacity is the same as the day-ahead market clearing, i.e 1 hour. No distinction between automatic and manual FRR components is made, instead a general FRR product is considered.

The model is formulated as a Mixed Integer Program (MIP) in GAMS[1] and solved using the CPLEX solver. The mathematical formulation for the most important equations in the MIP problem is provided in the following section. The reader is referred to the nomenclature for a more detailed explanation of the parameters and variables.

[1]Generic Algebraic Modelling System (GAMS) is a high-level modeling system for mathematical programming and optimization, and is designed specifically to solve complex, large scale mixed integer optimization problems [38]

3.1.1 Mathematical Formulation

The objective function shown in 3.1 has the objective of minimizing the overall cost associated with the DA market clearance, within a planning period τ.

$\forall \tau \in \Gamma$

$$min \sum_{z \in Z} \left\{ \sum_{t \in T} \left[\sum_{g \in G_z} \{ p_{z,g,\tau,t} \cdot MC_{z,g} + u_{z,g,\tau,t} \cdot SC_{z,g} + FC_{z,g} \cdot \delta_{z,g,\tau,t} \} + p^{cur}_{z,\tau,t} \cdot VLL + r^{cur,\uparrow/\downarrow}_{z,\tau,t} \cdot VLR \right] + \sum_{h \in H_z} \left[\left(Of_{z,h,\tau} + \sum_{t \in T} p^{st}_{z,h,\tau,t} \right) \cdot WV_{z,h,\tau} \right] \right\} \quad (3.1)$$

The cost function consist of the cost of thermal units, the cost of hydro units, the cost of load shedding and the cost of not providing a sufficient amount of FRR capacity ("reserve shedding"). The cost associated with thermal units is approximated by a startup cost and a linear output dependant cost function represented by a fixed cost component and a constant marginal cost. Hydro unit costs are represented by the cost of using or spilling water in the connecting reservoir. Because the FRR requirements are given as constraints to the problem, the function implicitly determines the optimal reserve capacity provided by each unit simultaneously with finding the optimal power output from each unit for each time step t. The optimal transmission capacity reserved for cross-border FRR exchange is also implicitly calculated for each t. The set of constraints defining the solution domain is given in equations 3.2 to 3.12.

$\forall g \in G_r, t \in T, \tau \in \Gamma, z \in Z$

$$p_{z,g,\tau,t} \geq \delta_{z,g,\tau,t} \cdot \underline{P}_{z,g} + r^{\downarrow}_{z,g,t} \quad (3.2)$$

$$p_{z,g,\tau,t} \leq \delta_{z,g,\tau,t} \cdot \overline{P}_{z,g} - r^{\uparrow}_{z,g,t} \quad (3.3)$$

Equation 3.2 ensures that the output of a regulating thermal unit is greater than the minimum capacity plus the downward FRR provided by the unit. Conversely, equation 3.3 restricts the output of a regulating thermal unit to be less than the maximum generation capacity less the upward FRR provision of the unit. The constraints for the output of hydro units are the same, except for the omission of the binary variable. The reason for this is the fact that there are no startup costs associated with hydro units. For non-regulating thermal units the same constraints are applied without the FRR components, and by changing the generator domain to $\forall g \in G_B$.

$\forall \tau \in \Gamma, t \in T, z \in Z$

$$p^{inj}_{z,\tau,t} = \sum_{g \in G_z} p_{z,g,\tau,t} + \sum_{h \in H_z} [p^{st}_{z,h,\tau,t} + p^{ns}_{z,h,\tau,t}] + p^{s}_{z,\tau,t} + p^{w}_{z,\tau,t} + \sum_{y \in Z} p^{DC}_{y,z,\tau,t} - PL_{z,\tau,t} + p^{cur}_{z,\tau,t} \quad (3.4)$$

$$p^{inj}_{z,\tau,t} = \sum_{y} p^{AC}_{z,y,\tau,t} \quad (3.5)$$

$\forall z, y \in Z, \tau \in \Gamma, t \in T$

$$p^{AC}_{z,y,\tau,t} = \sum_{v \in Z} \psi_{z,y,v} \cdot p^{inj}_{v,\tau,t} \quad (3.6)$$

Equation 3.4 makes sure that the injected power in a zone is equal to the sum of all generation in the zone, minus the overall load within the zone, plus the sum of all injections from HVDC lines connected to the zone. Equation 3.5 ensures that the power injected in zone z is exported to all adjacent zones connected to the zone. Furthermore 3.6 defines the flow between zones z and y by utilizing the PTDF and injection matrices.

$\forall z \in Z, \tau \in \Gamma, t \in T$

$$p^{w/s}_{z,\tau,t} \leq \overline{P}^{w/s}_{z,\tau,t} \quad (3.7)$$

Equation 3.7 restricts the output of solar and wind units in a given zone to be less than or equal to the available production.

$\forall a \in A, \tau \in \Gamma, t \in T$

$$Rr^{\uparrow/\downarrow}_{a,\tau} = \sum_{z\in Z_a} rp^{\uparrow/\downarrow}_{z,\tau,t} - \sum_{z\in Z_a}\sum_{y} tr^{(AC)\uparrow/\downarrow}_{z,y,\tau,t} - \sum_{z\in Z_a}\sum_{y} tr^{(DC)\uparrow/\downarrow}_{z,y,\tau,t} + \sum_{z\in Z_a} r^{cur,\uparrow/\downarrow}_{z,\tau,t} \tag{3.8}$$

Equation 3.8 states that for a given planning period τ, the upward and downward FRR requirement in balancing area a equals the FRR procured in all zones within the balancing area reduced by the amount exported to other areas on HVDC and AC interconnectors plus the amount of reserves not provided for all time steps t.

$\forall z, y \in Z, \tau \in \Gamma, t \in T$

$$-\overline{P}^{DC/AC}_{z,y} \leq tr^{(DC)/(AC)\uparrow}_{z,y,\tau,t} + p^{DC/AC}_{z,y,\tau,t} \leq \overline{P}^{DC/AC}_{z,y} \tag{3.9}$$

$$tr^{(DC)/(AC)\downarrow}_{z,y,\tau,t} \leq p^{DC/AC}_{z,y,\tau,t} + tr^{(DC)/(AC)\uparrow}_{z,y,\tau,t} \tag{3.10}$$

$\forall z \in Z, g \in G_R, h, \tau \in \Gamma, t \in T$

$$r^{\uparrow/\downarrow}_{z,g/h,\tau,t} \leq \overline{R}^{\uparrow/\downarrow}_{z,g/h} \tag{3.11}$$

$\forall z \in Z, \tau \in \Gamma, t \in T$

$$rp^{\uparrow/\downarrow}_{z,\tau,t} = \sum_{g\in G_z \cap g\in G_R} r^{\uparrow/\downarrow}_{z,g,\tau,t} + \sum_{h\in H_z} r^{\uparrow/\downarrow}_{z,h,\tau,t} \tag{3.12}$$

Equation 3.9 states that the sum of upward FRR and energy exchange from zone z to zone y should not exceed the maximum capacity of the HVDC or AC line connecting the two zones. A similar restriction pertaining to downward reserves can be seen in equation 3.10, which states that the amount of downward FRR exchanged must be less than or equal to the sum of upward FRR exchange and energy exchanged between the respective zones. Equation 3.11 restricts the upward and downward FRR provided by a unit to be less than the maximum possible FRR provision of the unit. Meanwhile equation 3.12 states that the total upward or downward FRR procured within a zone is the sum of the FRR provided by individual regulating hydro and thermal units in the zone.

3.2 Case Study

This thesis considers the Northern European power system in a 2030 state with large scale integration of Renewable Energy Sources (RES). The case study is largely based on data modified from [12]. Two scenarios of ENTSO-E's Ten Year Network Development Plan (TYNDP) [2], are also extensively used as data sources. These scenarios are vision 4 of the 2016 TYNDP and the EUCO30 scenario of the 2018 TYNDP. Vision 4 is called "European Green Revolution" and reflects favourable financial conditions for RES. The EUCO 30 scenario is a main policy scenario developed by the European Commission, which models the 2030 climate and energy targets as agreed by the European Council in 2014 [40].

The complete system considered is shown in figure 3.1. Nodes are aggregated to equivalent zones, and each generator and load is connected to their respective aggregated zone. Inter-zonal transmission lines are also aggregated to form a single equivalent transmission line connecting the relevant zones. Intra-zonal transmission lines are not considered in this case study. The zonal division is based on country borders, bottlenecks in the system, as well as the geographic distribution of generation capacity [21]. A group of zones constitute a balancing area, which corresponds to price areas in Great Britain, Netherlands and the Nordic system. For the German system the balancing areas correspond to the four German TSO control areas. These balancing areas in turn form four distinct balancing regions, namely the Nordic system, Germany and Western Denmark, the Netherlands and Great Britain. Two cases are analyzed:

- Case 1: FRR procurement *without* the possibility of exchanging reserves between balancing regions[3]. This is used as a reference case, and reflects the current state of the system.
- Case 2: FRR procurement *with* the possibility of exchanging reserves between balancing

[2]The TYNDP is a pan-European network development plan drafted by ENTSO-E every two years, which serves as a basis for the selection of EU projects. The TYNDP presents several visions which reflect plausible future states of the European power system [39]

[3]It is worth noting that even though there is no reservation of transmission capacity for FRR exchange between regions or inter-regional procurement of reserves, it is still possible to procure reserves from other balancing areas, if the areas are within the same balancing region.

regions[4]. This case simulates a fully integrated FRR procurement market.

Both case 1 and case 2 assume that the sufficient harmonization between individual FRR procurement markets is in place.

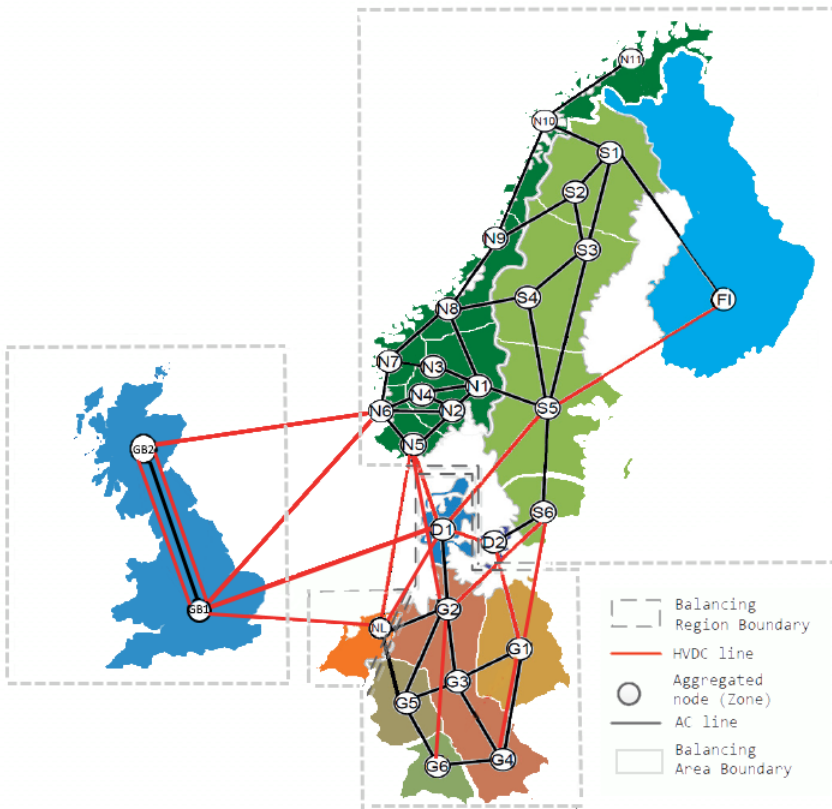


Figure 3.1: Northern European system considered in this case study. Adapted from [12]

3.2.1 Power Production

Generation units are categorized as base-load units, regulating units, or non-dispatchable units based on their response speed and controllability [12]. Only regulating units can provide reserve capacity. The total installed generation capacities for each country in the system considered is based on data from ENTSO-E's 2018 TYNDP EUCO30 scenario [41]. The installed capacity per generation source used in the case study is shown in table 3.1. Figure 3.2 provides a comparison of the distribution of generation capacity per source within each country.

[4]Maximum transmission capacity reservation for FRR exchange on inter-regional lines is set to 30%

Table 3.1: Installed capacity in Northern Europe in 2030 [MW]

Country	Biofuel	Gas	Hard Coal	Hydro	Lignite	Nuclear	Oil	PV	Wind
Germany	8 567	17 081	22 930	3 838	13 782	-	1 247	81 501	69 449
Denmark	2 827	788	1471	-	-	-	218	838	7505
Finland	3 384	2 792	818	3 000	-	3 398	1 109	19	4 140
Great Britain	17 760	28 713	501	1 649	-	13 107	2 579	10 860	37 662
Netherlands	2 690	10 379	4 429	-	-	485	2 066	5 933	10 235
Norway	-	-	-	28 000	-	-	-	800	5 540
Sweden	3 202	3 114	105	14 966	-	6 949	836	231	13 915
Total	38 427	62 876	30 254	51 453	13 782	23 939	8 055	100 182	148 446

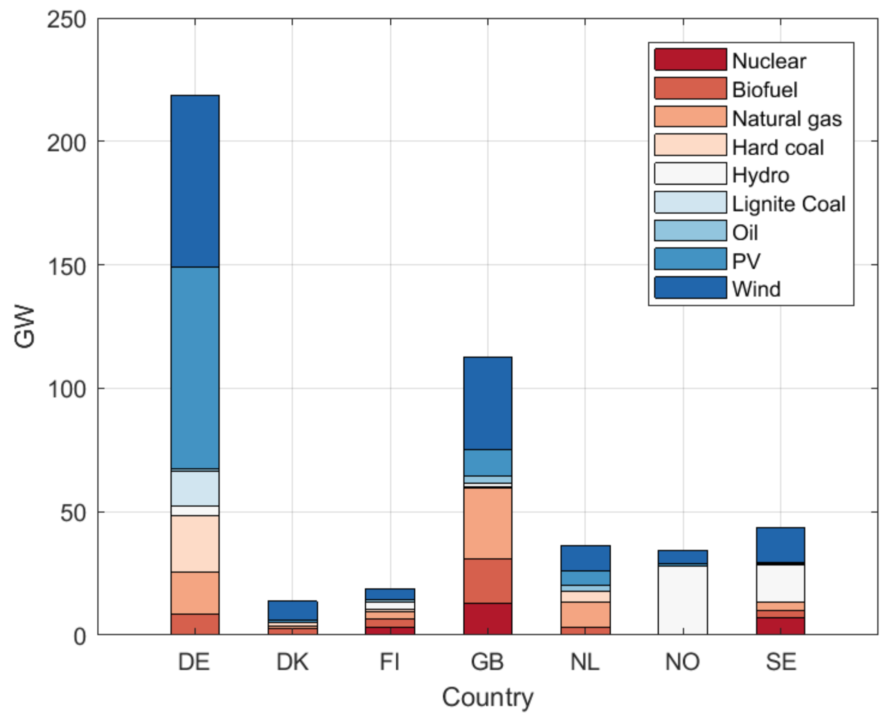


Figure 3.2: Installed generation capacity per country in 2030 scenario.

The total installed wind and PV capacity stands for 72.3 % of the total installed capacity in the system. Germany constitutes 60% of the total installed RES capacity. Another thing worth noting is the fact that all nuclear units in Germany have been decommissioned.

Hydro Power Production

Hydro power units are defined as regulating units. This work uses the same representation of the Nordic and German hydro power systems as used in [12]. A simplified and aggregated reservoir representation was obtained from the EMPS[5] model. 49 aggregated hydro plants obtained from the PSST[6] model have been assigned to their respective EMPS area. The hydro plants are directly connected to a reservoir, and inflow time series and reservoir capacity are scaled relative to the maximum hydro plant capacity in each of the EMPS areas.

There are virtually no direct costs associated with hydro production. There is however an opportunity cost, referred to as the water value (WV), associated with using the water in the reservoir now, compared to using the water in a later period [42]. In the model used the marginal cost of a hydro power plant is represented by its respective WV. The WV of a reservoir is dependent on the reservoir level, as well as various stochastic variables, namely the inflow to the reservoir, market prices and demand [43]. As a result the water values vary substantially from reservoir to reservoir, and are greatly dependent on the time of year.

No expansion of hydro power production is considered in this thesis. This means no increase installed capacity compared to the situation considered in [12], which reflects the system state in 2010. Pumped hydro is also not considered. In Great Britain hydro power production is defined by the annual production profile taken from [44].

Thermal Power Production

Thermal units based on oil, gas and hard coal are defined as regulating units, as they are characterized by a quick ramping speed. Nuclear, lignite coal and biofuel-based units are defined as base-load units, because of their long start-up time and the fact that they usually operate at their nominal operating point [12].

The marginal costs for each power plant are taken from the ADAPT datasheet [45], which

[5]EMPS or EFIs Multi-area Power market Simulator is a long term hydro power planning model developed by SINTEF Energy

[6]PSST - Power System Simulation Tool, is a DC optimal power flow based market model developed by SINTEF Energy Research

enables the calculation of marginal costs based on fuel price, CO_2 price and the year of construction. In the case study considered, fuel prices are taken from vision 4 of the 2016 TYNDP [46]. The only exception is the price of biofuel, which is taken from [45]. The fuel prices used are shown in table 3.2. The CO_2 price is adjusted up to 76 EURO/tonne, in accordance with vision 4 of the 2016 TYNDP. Fixed costs for power plants located in continental Europe are obtained from [12]. Fixed costs for units located in Great Britain are taken from [47]. Startup costs are approximated based on the installed capacity and marginal cost of the individual unit, and follows the same procedure as used in [12].

Table 3.2: Fuel type and fuel price

Fuel type	Fuel price (EUR/GJ)
Nuclear	0.46
Lignite coal	1.10
Hard coal	2.19
Gas	7.23
Light oil	13.26
Heavy oil	9.88
Biofuels	3.19

Information regarding the location and installed capacity of thermal power plants are taken from [12] for continental plants, and from [47] for Great Britain. The installed capacity per thermal power plant is then scaled so that the aggregated capacity for each fuel type within a country matches the installed capacity envisioned by the 2018 TYNDP's EUCO 2030 scenario [41]. It is assumed that all power plants are equally scaled relative to their prior installed capacity. This means that the share of capacity of each power plant relative to the total installed capacity of that fuel type within their respective country is held constant. The capacity of thermal power plants are also derated by using hourly availability factors obtained from [12].

Wind and PV Power Production

Wind and PV units are considered to be uncontrollable energy sources as their output depends on the weather. These sources are therefore unsuitable for the provision of reserve capacity.

Because there is no cost associated with using these resources for power generation, wind and PV generation is modelled as having a marginal cost equal to zero. If there are no congestions in the grid, their full potential will therefore be used.

Wind and PV time series data is based on the European Commission's EMHIRES [7] datasets [48] for the entire system, with the exception of Germany. The database is a set of data that models the energy production from currently installed wind and PV farms for every hour during the last 30 years. The dataset contains hourly capacity factors on a country and bidding area basis. These capacity factors have been multiplied by the installed capacity envisioned by the EUCO30 scenario, to obtain time series reflecting the wind and PV potential of each country in the system considered. Separate capacity factors and installed capacities for onshore and offshore wind have been used where possible, but the time series used reflects the aggregated wind potential within a zone. The spatial distribution of installed wind and PV capacity within a country or bidding area (i.e how much capacity is allocated to the zones defined in the case study, see 3.1) is the same as used in [12], thus assuming that the development of new PV and wind power units will follow the same geographical distribution within a country as seen today. For Great Britain the allocation reflects the distribution between Scotland and England/Wales.

For the German system, the time series for PV and wind production is based on real hourly production time series for each TSO area, freely available from [49]. The hourly production has been normalized with respect to installed capacity within each TSO area, taken from [50], to obtain capacity factors. Finally these capcity factors have been multiplied by the aggregated installed capacities given in the EUCO30 scenario, in order to arrive at hourly time series which reflect the 2030 wind and solar potential for each of the four German TSO areas. The allocation of installed capacity in Germany to the TSO areas is based on the current distribution of installed PV and wind capacity.

[7] European Meteorological derived HIgh resolution Renewable Energy Source generation time series

3.2.2 Load

The total yearly load per country is obtained from the EUCO30 vision. The consumption pattern used is taken from vision 4 of the 2016 TYNDP. The aggregated annual load for the system amounts to 1367.1 TWh. The allocation of load to each individual zone within a country or price area is done in a similar fashion as in [12] for continental Europe, thus assuming that the intra-national distribution of load does not change from a 2010 to a 2030 scenario. For Great Britain the distribution between the two zones reflects the distribution between Scotland and England/Wales. The consumption of each country is corrected for net export to neighbouring countries outside the power system considered. The cost of load shedding is set to 10,000 EUR/MWh.

3.2.3 Transmission System

The system considered is divided into 29 aggregated nodes connected by transmission corridors which represent aggregated transmission lines. The power transferred on these lines are restricted by their direction-dependant net transfer capacities (NTC). The NTC values used are taken from the TWENTIES report [51]. These values are based on the system state in 2010, but also take into account future plans for grid expansion.

The case study includes the commissioning of several new HVDC lines, as well as upgrades on existing ones. The list of HVDC connections considered in this case study, as well as their respective transmission capacities can be seen in table 3.3. As of June 2018 the last 10 interconnections shown in table 3.3 are not yet in operation. The most notable additions compared to the current state are North Sea Link and NorthConnect, connecting Norway with Great Britain, NordLink connecting Norway and Germany, as well as the intra-national HVDC connections connecting Scotland and England/Wales (Eastern/Western HVDC link), and SuedLink and SuedOstLink connecting Northern and Southern Germany.

Table 3.3: HVDC interconnections in Northern Europe in 2030

Name	From	To	Capacity (MW)
NorNed	Norway	Netherlands	700
Skagerrak	Norway	Denmark	1700
Konti-Skan	Denmark	Sweden	550
Baltic	Germany	Sweden	600
Great Belt	E. Denmark	W. Denmark	600
Kontek	Germany	E. Denmark	1200
Fenno-Skan	Finland	Sweden	1350
BritNed	Netherlands	England	1000
NordLink	Norway	Germany	1400
North Sea Link	Norway	England	1400
NorthConnect	Norway	Scotland	1400
Viking	W. Denmark	England	1400
Hansa Powerbridge	Germany	Sweden	700
Cobra	Netherlands	W. Denmark	700
Eastern HVDC Link	Scotland	England	2000
Western HVDC Link	Scotland	England	2200
SuedLink	N. Germany	S. Germany	2000
SuedOstLink	NE. Germany	S. Germany	2000

3.2.4 PTDF matrix

The PTDF matrix used in this work is a zonal matrix, providing information regarding the relationship between the change in net position of a zone and the subsequent distribution of power on the connecting aggregated transmission lines. Each synchronous power system, i.e the Nordic, British, and continental (Netherlands, Germany and Western Denmark) has its individual PTDF matrix.

The zonal PTDF matrices were derived from datasets obtained from [12], through the use of a script implemented in MATLAB by the author. The script uses the built in MATPOWER[8] function *MakePTDF* to obtain a nodal PTDF matrix for a given system. It then converts the nodal matrix to a zonal representation by way of pro rata aggregation, i.e the contribution

[8]MATPOWER is a package of free, open-source Matlab-language M-files for solving steady-state power system simulation and optimization problems such as power flow (PF), continuation power flow (CPF), extensible optimal power flow (OPF), unit commitment (UC) and stochastic, secure multi-interval OPF/UC [52]

the change in net position a node has on the net position of the zone it is situated in is equally weighted for all nodes. The script uses an input file similar to the standard MATPOWER case format, the only difference being that the zone in which a node is situated in must be included. The script is generic and can be used on any synchronous system. The MATLAB code is provided in appendix A. There are several other aggregation methods that could have been utilized. The choice came down to the fact that the pro rata method allows for the predetermination of the aggregated PTDFs, reducing the computation time of the simulation runs [21].

3.2.5 Reserve Requirements

The FRR requirements for continental Europe are the same as used in [12]. For Great Britain the FRR requirement is taken from the British TSO National Grid. The requirements are symmetric, i.e the same amount of reserves is needed in both upward and downward directions. They are also static, i.e they are equal for all planning periods considered. The requirement per country is listed in table 3.4.

Table 3.4: FRR requirement per country [MW]

	Norway	Sweden	Denmark	Finland	Germany	Netherlands	Great Britain
Reserve requirement	1200	1220	524	865	2662	300	1260

A minimum of two thirds of the reserve requirement of a balancing area must be reserved from its own area. Furthermore up to 10% of the transmission capacity between adjacent zones may be used for FRR exchange. Each regulating unit can use a maximum of 20% of its capacity for upward and downward reserve provision. The cost associated with not providing enough FRR capacity is equal to the cost of load shedding, i.e 10,000 EUR/MW.

It should be noted that 100 MW is pre-allocated for FRR exchange from southern Norway (bidding zone N1 in figure 3.1) to western Denmark on the Skagerrak cable. This is in line with the arrangement currently in place [53]. As a result the capacity on the Skagerrak cable available to the model is reduced by 100 MW.

Chapter 4 | Results and Discussion

This section presents and discusses the simulation results obtained from applying the model to the case study. In particular the total system cost, the spatial distribution of procured reserves and the utilization of inter-regional transmission capacity for FRR exchange are analyzed.

4.1 Generation Adequacy

A significant amount of load shedding is observed for both case 1 and case 2. The distribution among countries is shown in table 4.1.

Table 4.1: Total load shed within a year [GWh]

	Norway	Sweden	Finland	Denmark	Germany	Netherlands	Great Britain	Total
Case 1	1.34	0.00	0.01	55.12	2887.5	17.11	0.00	2961.1
Case 2	3.86	0.00	0.30	45.03	2784.8	23.48	0.00	2857.5

One can observe that for both case 1 and 2 Germany experiences quite substantial load shedding, amounting to approximately 0.5 % of the total German load. This is due to the fact that the scenario considered involves a large-scale decommissioning of thermal units and a large increase in solar and wind power, leading to a large share of intermittent energy sources in the German power system. With load shedding cost set to 10,000 EUR/MWh, the cost associated with load shedding in Germany alone amounts to EUR 28.9 billion and 27.8 billion for case 1 and case 2 respectively. This skews the system cost obtained from the model, making it difficult to draw any conclusions regarding the cost benefits of integrating reserve markets. Furthermore the shedding also affects the amount of inter-regional transmission capacity reserved for FRR exchange, leading to a non-representative spatial distribution of procured reserves.

The German system stands for 98% and 97% of the observed load shedding for case 1 and case 2 respectively. In order to accurately quantify the benefits of integrating FRR procurement markets, the analyses made in the following sections are conducted with the assumption that sufficient demand side response is in place in Germany. This is implemented by subtracting the amount of hourly load shedding observed for case 2 in each German control area from the actual hourly load, and then re-running the model for both cases considered. This should theoretically filter out the distorting effect the German shedding cost has on the system cost and spatial distribution of procured reserves.

4.2 System Costs

The total system cost, day-ahead market costs, load shedding costs, unprovided FRR costs and FRR procurement cost for both cases considered are shown in table 4.2. The FRR procurement costs are approximated by running the model with and without FRR requirements, taking the total cost difference, and then subtracting load shedding costs, and costs associated with unprovided FRR capacity.

Table 4.2: System costs [billion EUR]

	Total	Day-ahead	Load shedding	Unprovided FRR	FRR procurement
Case 1	40.73	37.27	1.91	0.706	0.84
Case 2	38.76	37.27	0.76	0.054	0.68

A total cost reduction of EUR 1.97 billion per year is observed when allowing inter-regional procurement of reserves. This is equivalent to 4.8% of the total system cost seen in case 1. One can observe that even when filtering out the load shedding initially observed in Germany, there are still substantial load shedding costs in case 1. For case 2 this cost is decreased by EUR 1.15 billion. A significant reduction in cost penalties associated with unprovided FRR is also observed as a result of integration, as this cost is reduced by 92.3%. The reduction in FRR procurement costs amounts to EUR 160 million, which is 19% of the procurement cost seen in case 1.

Figure 4.1 shows the difference in daily system costs between case 1 and case 2, and the daily net load (load minus RES production) of the system. One can observe that there is a correlation between the two. In the winter when the net load is high, the cost difference is also higher. This can be explained by the fact that during the winter both the load and wind power generation are high. In areas where wind power constitutes a large share of the installed capacity, the generation adequacy therefore becomes very sensitive to changes in wind production. As a result during times of low wind, load shedding will be significant. The value of increased generation flexibility enabled by integration therefore becomes more pronounced in these time periods.

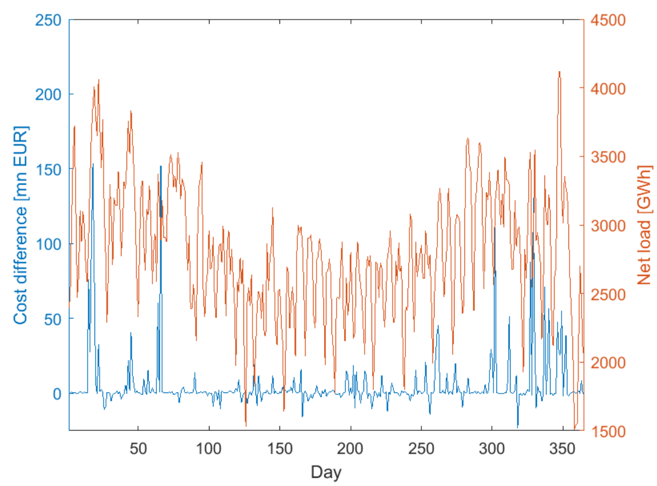
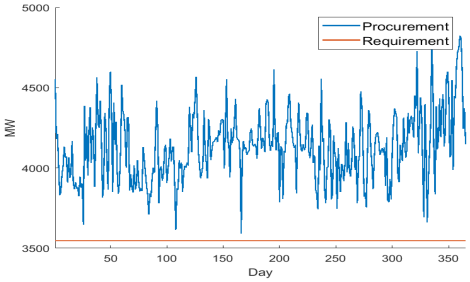


Figure 4.1: Total cost difference (case 1 minus case 2) and net load time series

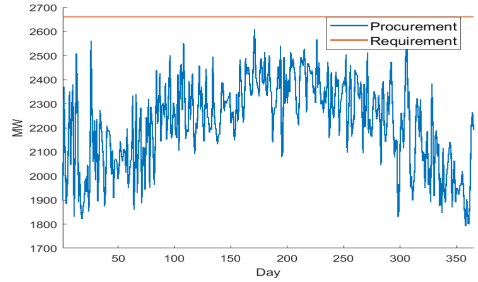
4.3 FRR Procurement and Exchange

Figure 4.2 and figure 4.3 show the annual procured upward and downward FRR in each balancing region compared to the region's FRR requirement for case 2.

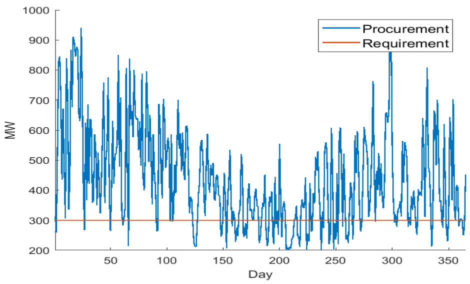
It can be observed that the Nordic region provides substantially more FRR than its regional



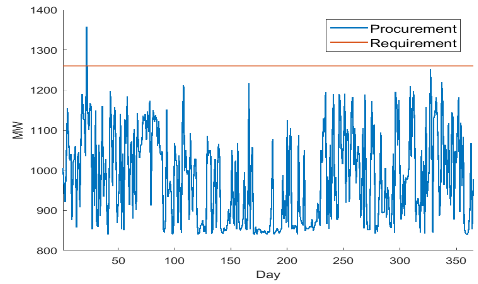
(a) Nordic region



(b) Germany and West Denmark

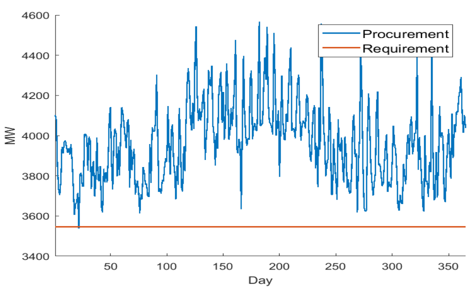


(c) Netherlands

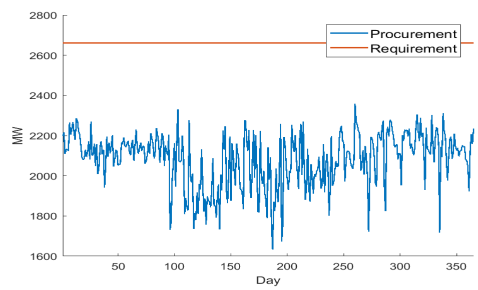


(d) Great Britain

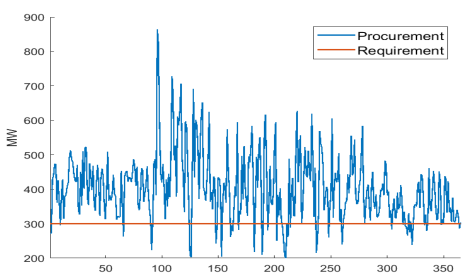
Figure 4.2: Average daily upward FRR procurement and requirement per region



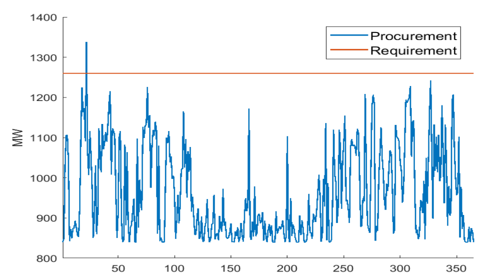
(a) Nordic region



(b) Germany and West Denmark



(c) Netherlands

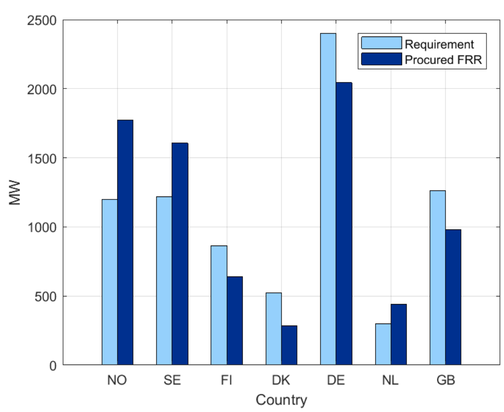


(d) Great Britain

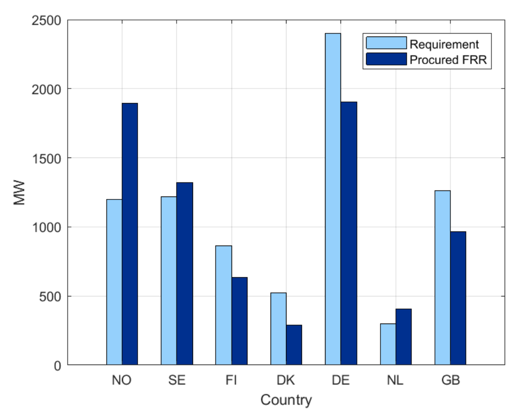
Figure 4.3: Average daily downward FRR procurement and requirement per region

requirement in both upward and downward directions for all days considered. This can be attributed to the large amount of cheap, flexible hydro power in this region. The Netherlands also provide more FRR than its requirement in both directions for a majority of the time. This may be explained by the fact that the Dutch FRR requirement is low when compared to its peak demand. Great Britain and Germany and West Denmark both provide less FRR than their requirement for virtually all days considered, signalling that they import cheaper reserves from other regions.

If we examine the average annual procurement of FRR within each country for case 2, as seen in figure 4.4, it is evident that Norway is the country that provides the most FRR in both upward and downward directions compared to its requirement. On average Norway provides 48% more than its requirement in the upward direction, and 58% in the downward direction. Sweden also provides significantly more reserves compared to its requirement. Denmark is the biggest importer with more than half of its required reserve being imported on average. Germany, Great Britain and Finland also import a significant part of their reserve requirement from adjacent areas on average.



(a) Upward FRR



(b) Downward FRR

Figure 4.4: Average annual upward and downward FRR procurement and requirement per country

Table 4.3 shows the average exchange of FRR from the Nordic region to the other regions in the system. One can observe that the exchange of upward FRR is split relatively equally between Great Britain and Germany, with a small amount being exported to the Dutch system. For the downward FRR, the majority of the reserves (70%) is exported to Great Britain. An interesting observation is the fact that approximately 23% of Great Britain's downward reserve requirement and 22% of its upward requirement is provided by the Nordic region on average.

Table 4.3: Average FRR exchange from the Nordic region in case 2 [MWh]

		DE + DK west	NL	GB	Total
Nordic	Upward	286	25	274	585
	Downward	114	12	292	418

Table 4.4 shows the annual amount of FRR not provided in each country relative to the annual FRR requirement for both cases considered.

Table 4.4: FRR not provided as a percentage of annual requirement (%)

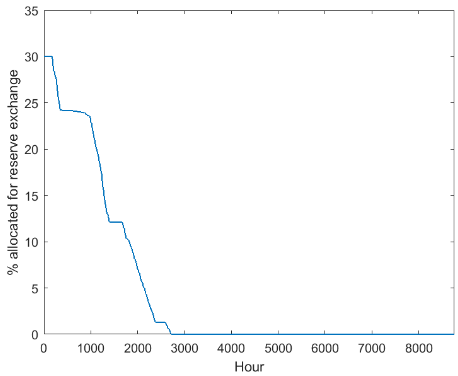
		Norway	Sweden	Denmark	Finland	Germany	Netherlands	Great Britain
Case 1	Upward	0.00	0.00	0.00	0.33	0.00	0.20	7.30
	Downward	0.00	0.00	0.00	0.63	0.00	0.20	7.30
Case 2	Upward	0.00	0.00	0.00	0.16	0.00	0.00	0.00
	Downward	0.00	0.00	0.00	0.64	0.00	0.00	0.00

The results indicate that Great Britain has an insufficient amount of reserve capacity for case 1, as 7.3% of the annual reserve requirement remains unprovided. This insufficiency is not observed for case 2, indicating that the integration of FRR procurement markets ensures the adequate provision of FRR capacity in Great Britain.

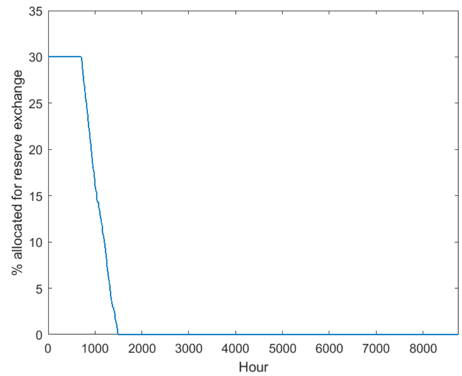
4.4 Optimal Allocation of Transmission Capacity

The optimal hourly allocation of transmission capacity for FRR exchange for a selection of HVDC lines connecting balancing regions has been sorted in a descending order and is shown in figure 4.5.

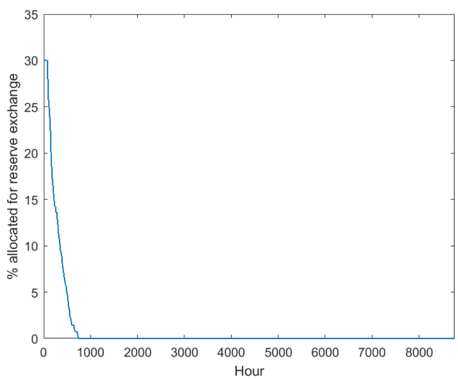
One can observe that capacity on North Sea Link and NorthConnect is reserved for FRR exchange for a substantial amount of hours within a year. For North Sea Link a reservation



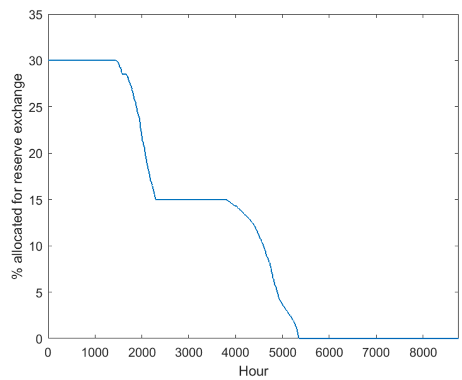
(a) Skagerrak



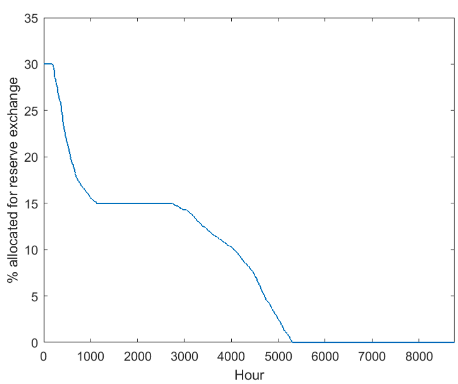
(b) NorNed



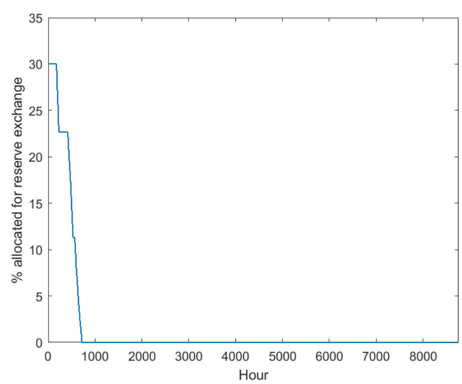
(c) NordLink



(d) North Sea Link



(e) NorthConnect



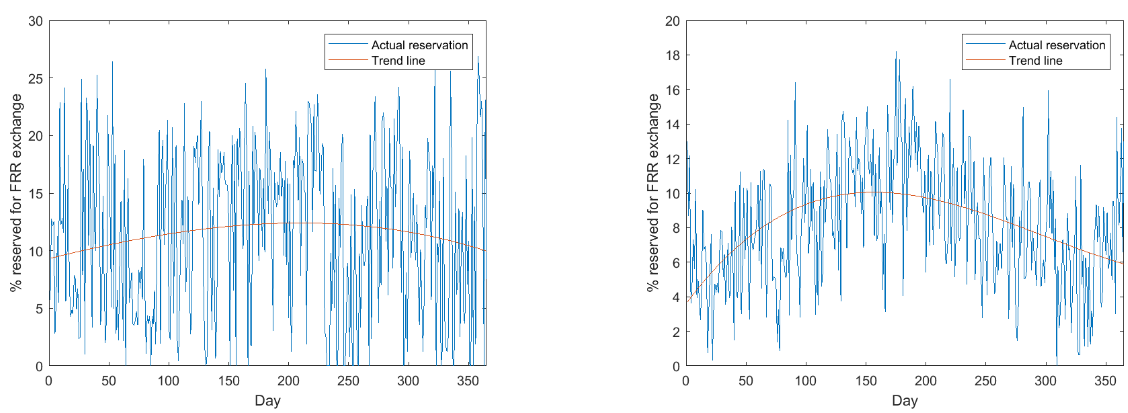
(f) Hansa Powerbridge

Figure 4.5: Optimal transmission capacity reservation for FRR exchange

is made 61 % of the time, while this number equals 60 % for NorthConnect. One may also observe that there are two reservation plateaus for North Sea Link at 30% and 15% and one at 15% for NorthConnect. A 30% reservation on either cable corresponds to 420 MW of FRR exchange between Norway and Great Britain, which is one third of Great Britain's FRR requirement. A simultaneous reservation of 15% on both lines also corresponds to 420 MW of FRR exchange. As each control area is restricted to procure two thirds of their reserve requirement from within their own balancing area, this represents the maximum allowable FRR import to Great Britain. This suggests that North Sea Link and NorthConnect may play a crucial role in providing Great Britain with a sufficient amount of reserves.

The Skagerrak cable is also reserved for FRR exchange for a significant amount of time. For 31 % of the hours considered reservation is made for FRR exchange. Interestingly, a reservation for FRR exchange is made for only 8% of the hours considered on the NordLink cable. This may be explained by the fact that the Northern part of the TenneT control area (G2 in figure 3.1) has a substantial amount of wind capacity installed. Furthermore G2 is also connected to the Transnet control area (G6 in figure 3.1) through the SudLink HVDC connection. This area has a large share of power coming from PV plants. Because of the large share of intermittent generation there will be frequent periods with low power production and thus a need for additional energy to be imported in order to avoid the cost penalty of load shedding. As a result energy exchange is prioritized over FRR exchange on the NordLink cable.

Figure 4.6 shows the average daily reservation for reserve exchange on North Sea Link and NorthConnect. The trend line is a 3rd degree polynomial fitted to the data points.



(a) North Sea Link

(b) NorthConnect

Figure 4.6: Average daily capacity reservation for FRR exchange on North Sea Link and NorthConnect.

One may observe that the reservation for FRR exchange on the North Sea Link cable fluctuates around 10% for the entire year, with no notable seasonal variations. For the NorthConnect cable a clear seasonal trend is observed. More transmission capacity is reserved for FRR exchange during the summer months, and less during the winter months. This may be explained by the fact that Scotland has a high share of wind power. During the winter when the load is higher the generation is not able to cover the load for hours with low wind power generation. As a result there is a need to import more energy through the NorthConnect cable, decreasing the amount of transmission capacity reserved for FRR exchange.

4.5 Discussion

Comparing the results obtained in this thesis with the results found by Farahmand et al. in [4], we can observe that the savings in reserve procurement costs as a result of market integration are fairly similar, amounting to EUR 160 million and EUR 226.4 million respectively. The reason for the difference may be the fact that their case study includes an offshore supergrid which enables more reserves to be exchanged between regions.

In addition to the reduction in FRR procurement costs, the results in this thesis indicate that integration of FRR procurement markets can decrease the amount of load shed and the amount of unprovided FRR in the system, thus decreasing the total system costs even further and increasing the reliability of the system. The reason for this is the fact that integration allows for a more flexible utilization of generation capacity in the system. Though there in reality does not exist a monetary cost of not providing enough FRR capacity to meet the FRR requirement, the use of a cost penalty for unprovided FRR in the model enables the analysis of the adequacy of FRR capacity in the system, which can be considered to be a good metric for system reliability.

The large amount of load shedding initially observed in Germany for both case 1 and 2 indicates that the large-scale integration of RES, combined with the decommissioning of thermal units leads to generation inadequacy in time periods with low RES penetration. Though the amount of load shedding is reduced as a result of reserve market integration, the amount of load shedding observed is still not sustainable. One way the generation inadequacy could be mitigated is by incorporating long term reserve capacity markets, where capacity can be procured for periods several years after the date of procurement. Both existing and non-existing (i.e planned construction) power plants, as well as demand response providers should be allowed to participate in this market. Such a market is already in place in Great Britain, and there is an ongoing debate on whether to implement a similar solution in other European countries.

Another way to deal with the gap between generation and consumption observed in Germany could be to more actively incorporate demand response to reduce consumption in periods with low amount of RES generation. This means that industry and consumers can receive compensation for shifting their consumption to fit the needs of the system. Though demand response has been implemented to some degree in many countries, there is still a large untapped potential associated with flexibility delivered from the demand side. With the development of smart meters and components, and increasing focus on IT-infrastructure in the power sector, the use of demand response to deal with imbalances may play an increasingly important role in the future.

The Nordics and especially Norway exports a large amount of FRR in the case study considered. The reason for this is the fact that the Nordic region has an abundance of cheap, flexible hydro power. The procurement of FRR is therefore shifted from the more expensive thermal units located in the rest of the system, leading to cost reductions. These findings are in line with the results of [4] and [21]. This suggests that by integrating FRR procurement markets the Nordic region may assume the role of a "green battery" for the rest of the Northern European system, providing the necessary reserves to be utilized in the event of low RES generation. This may present a lucrative opportunity for Nordic hydro power units to participate more actively in the FRR procurement market in the future.

The significant amount of unprovided FRR in Great Britain observed for case 1, indicates that there is an inadequate supply of FRR capacity in this area. The large amount of FRR exchange observed from the Nordic region to Great Britain on the North Sea Link and North-Connect HVDC cables in case 2, suggests that the construction of these interconnections may play a crucial role in providing Great Britain with reserves in the future.

4.5.1 Limitations and Sources of Error

The model used in this thesis work is a unit commitment model. The European electricity is a combination of bilateral trading and trading through power exchanges. As result a unit commitment model does not perfectly reflect the European electricity market. That being said, if one assumes perfect competition, the generation pattern obtained from a unit commitment model should give a good indication of the market outcome [3].

The assumption that demand response is able to fully cope with the time periods with low supply of electricity in Germany entails that sufficient infrastructure and regulations to facilitate large shifts in demand is in place. This could be an overambitious assumption, but the rapid smart grid development seen today suggests that demand response will become an increasingly viable option when it comes to maintaining the system balance in times of low RES penetration.

Transmission capacities of AC-lines have been updated in an attempt to incorporate the future system development. That being said, the future development of which these values are based on reflects the planned expansion outlined by ENTSO-E's 2011 TYNDP. As such the system representation does not perfectly reflect a 2030 state. Moreover, the NTC values used in the case study are static, i.e equal for all days considered. In reality these are dynamic values that vary within a year.

Another limitation of the analysis conducted is the fact that the reserve requirements used have not been adjusted to reflect the increase in RES penetration. As a result the requirements are underestimated. Reserve requirement used are also static. In reality these are calculated based on predicted forecast errors and vary substantially within a year.

A simplification made is the fact that the capacity of thermal generation units is scaled up or down in order for the aggregated installed capacity within a country to reflect a representative 2030 scenario. To better approximate the spatial distribution of thermal capacity in 2030, existing units should be decommissioned and new ones added, instead of scaling existing ones. This being said, with the availability of information regarding the future development of individual units being scarce, the scaling approach provides a good estimate.

The installed hydro power capacity of each country was not scaled to reflect the 2030 values envisioned by the 2018 TYNDP. As a result hydro power capacity is underestimated in the case study considered. This is especially true for Norway which according to the EUCO30 vision increases its installed capacity by almost 28% by 2030, compared to the installed capacity used in this thesis. With more installed hydro capacity, the amount of FRR procured in Norway would probably increase, and the FRR procurement cost of the system for the integrated case would likely decrease even further, making the value of integration even more pronounced. A large increase in hydro power is also envisioned in Germany by the EUCO30 scenario. This would decrease the amount of shedding observed in this area, possibly making the cost benefits of integrating FRR procurement markets less pronounced.

Another limitation of this work is the use of area-based capacity factors for PV and wind production. To obtain a complete picture of the RES production, capacity factors for each individual unit could be used. That being said the use of area based capacity factors and installed capacity should give a decent representation of the hourly RES production in the system. The aggregation of offshore and onshore wind is another simplification made. To increase the accuracy of the results these two should be separated. This would necessitate the addition of offshore nodes connected to the mainland through an offshore grid.

The fixed reservation of 100 MW for reserve exchange on the Skagerrak connection also constitutes a limitation of the analysis conducted. The reason for this fixed reservation is the fact that Eastern Denmark did not have a sufficient amount of FRR capacity to fulfill its FRR requirements in preliminary simulation runs, making the problem infeasible. Farahmand et al. showed in [4] that a pre-reservation of 100 MW for reserve exchange on the Skagerrak cable results in an increase in procurement costs of EUR 6 million compared to the no reservation case. This number is very small compared to the cost savings observed in this thesis, suggesting that the fixed reservation is likely to only have a minor impact on the results obtained.

Chapter 5 | Conclusion and Further Work

5.1 Conclusion

The anticipated increase in power generation stemming from uncontrollable sources such as wind and solar, poses a significant challenge in the context of system balancing, increasing the importance of reserve procurement and balancing energy activation. This thesis focuses on the effects of integrating FRR procurement markets in a hypothetical 2030 Northern European system consisting of the Nordic countries, Germany, the Netherlands and Great Britain, with a large RES share. The results indicate that the availability of the flexible and inexpensive hydro power resources in the Nordic region can reduce the amount of reserves procured from thermal units in the rest of the system, thereby reducing the FRR procurement costs. Furthermore the increased generation flexibility enabled by integration leads to less load shed and less unprovided FRR capacity in the system considered. As a result integration leads to a 4.8% reduction in total system costs, when compared to the non-integrated case.

An interesting observation is Great Britain's inadequate supply of FRR capacity in the non-integrated scenario. The results indicate that 7.3% of Great Britain's FRR requirement remains unprovided in the non-integrated case. For the integrated case this insufficiency is no longer observed. A reservation of transmission capacity for the exchange of FRR is made 61% and 60% of the time on the North Sea Link and North Connect HVDC cables respectively. This in combination with the fact that Great Britain on average procures 23% of its downward FRR requirement and 22% of its upward FRR requirement from the Nordic region indicates that Nordic hydro power may play an important role in supplying the British system with FRR capacity in the future.

5.2 Recommendations for Further Work

A static reserve requirement was used in this work. As the amount of RES increases in the power system, the need for a dynamic requirement will increase because of the stochastic imbalances associated with RES. Future work should therefore investigate the impact different reserve sizing approaches has on cross-border procurement of reserves, and the added value the respective approaches yield. Especially different probabilistic approaches should be investigated.

To quantify the effect RES has on the cost benefits associated with reserve exchange, a sensitivity analysis which varies the installed RES capacity in the system should be conducted. Furthermore an analysis comparing the benefits when using the different visions of ENTSO-E's TYNDP as input data would be of great interest.

A dynamic allocation of transmission capacity puts a substantial amount of strain on the power system, due to the increased uncertainty regarding power flows. A fixed reservation is therefore favoured by TSOs, if the social welfare loss is not significant. A sensitivity analysis that looks at how fixed reservations for FRR exchange on different inter-regional transmission lines affect the system cost and distribution of procured reserves is therefore highly relevant.

An interesting and increasingly relevant topic that could be addressed in future work is how other types of reserve provision than conventional generation, e.g distributed generation, demand response and battery storage could be implemented in the reserve market, and what effect this would have on the cost of reserve procurement and spatial distribution of reserves.

Another interesting analysis that could be conducted is to look at the effect integration has on regional FRR prices. This could be achieved by finding an optimal solution for the MIP problem, and then fixing the binary variables to obtain an LP representation of the problem.

The regional FRR prices could then be found from the dual of the regional reserve requirement constraint. By obtaining the FRR price time series for a year, an analysis looking at the how profitable it is for Nordic hydro producers to participate in a future integrated reserve market could be conducted.

In order to obtain a complete representation of an integrated Northern European balancing market, the model used should be extended to include the balancing energy market. To give an even more complete representation of the electricity market, the intra-day market could be incorporated in between the day-ahead and FRR procurement market and balancing energy market.

The model used in this thesis only considers a general FRR product. In reality there is a distinction between automatic and manual FRR. Future work should therefore seek to separate these components, as doing so will lead to a more accurate outcome of the FRR procurement process.

Finally, this thesis only looks a the overall cost benefits of integrating FRR procurement markets. The impact on market players, i.e producers, consumers and TSOs is not considered. A relevant analysis would be to investigate which players benefit from integration, and which players do not benefit from integration, as this could help identify potential barriers for the implementation of an integrated FRR procurement market.

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Appendix A. Matlab Code for Calculation of PTDF

```
%This code generates and converts a nodal PTDF matrix to a
%zonal PTDF matrix by way of pro rata aggregation.
%It uses an input file similar to the standard case format used in
%Matpower, the only difference being the inclusion of the zone
    number in
%which a bus is situated in.
%The buses must also be ordered according to which zone they are
    in.

%Count number of zones, nodes, lines and nodes within each zone
%and identify interconnectors
number_zones = max(mpc.bus(:,14));
number_nodes = length(mpc.bus(:,1));
num_lines = length(mpc.branch(:,1));
num_nodes_in_zone = zeros(number_zones,1);
interconnectors = find(mpc.branch(:,18) ~= mpc.branch(:,19));
for j=1:number_zones
num_nodes_in_zone(j,1) = length(mpc.bus(mpc.bus(:,14) ==j));
end
```

```
%creating nodal PTDF matrix by using built in matpower function and
%retrieving PTDF matrix for interconnectors:
nodalPTDF = makePTDF(100, mpc.bus, mpc.branch, 1);
interconnectorPTDF =nodalPTDF(interconnectors,:);

%creating zonal PTDF matrix for interzonal lines using pro rata aggregation
%(equal weighting for each node)
for i = 1:number_zones
  for l = 1:size(interconnectors,1)
  if i == 1
      zonalPTDF(l,i) = mean(interconnectorPTDF(l,1:num_nodes_in_zone(i)));
  else
      zonalPTDF(l,i) = mean(interconnectorPTDF(l,sum(num_nodes_in_zone(1:i-1))+...
        1:sum(num_nodes_in_zone(1:i-1))+num_nodes_in_zone(i)));
  end

  end
end

%aggregating PTDF values for lines connecting the same zones
interconnectorBranches = mpc.branch(interconnectors,:);
numberedPTDF = [interconnectorBranches(:,18) interconnectorBranches(:,19) zonalPTDF];
[values, ~, ids] = unique(numberedPTDF(:, [1 2]), 'rows');
summedZonalPTDF = splitapply(@(rows) sum(rows, 1), numberedPTDF,
```

```
    ids);
summedZonalPTDF(:,1:2) = values;

%Configuration of lines (from - to) can be the other way around,
    must consider this
x=(summedZonalPTDF(:,1).*summedZonalPTDF(:,2))+mean(
    summedZonalPTDF(:,1:2)')';
[C, ia, ic] = unique(x,'rows');
duplicate_indx = setdiff(1:length(x), ia);
for i = length(duplicate_indx):-1:1
    dupvec(:,i) = find(x==x(duplicate_indx(i)));
    summedZonalPTDF(dupvec(1,i),3:end) = summedZonalPTDF(dupvec(1,
        i),3:end)-...
        summedZonalPTDF(dupvec(2,i),3:end);
    summedZonalPTDF(dupvec(2,i),:) =[];
end
```