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# Integrated Power System Balancing in Northern Europe - Models and Case Studies

Thesis for the degree of Philosophiae Doctor

Trondheim, June 2012

Norwegian University of Science and Technology  
Faculty of Information Technology, Mathematics and Electrical  
Engineering  
Department of Electric Power Engineering



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ISBN 978-82-471-3587-7 (printed ver.)  
ISBN 978-82-471-3588-4 (electronic ver.)  
ISSN 1503-8181

Doctoral theses at NTNU,2012:150

Printed in Norway by NTNU-trykk, Trondheim

# Preface

This thesis is submitted in partial fulfilment of the requirements for the degree of philosophiae doctor (PhD) at the Norwegian University of Sciences and Technology (NTNU) in Trondheim. The research was supported by the Norwegian Research Council(1784677/S3), the Next Generation Infrastructures Foundation in the Netherlands, the Norwegian and Dutch TSOs, the Norwegian regulator NVE and power producers Statkraft, Sira-Kvina, BKK, Agder Energi Produksjon and GDF Suez.

## Acknowledgements

I would like to express my gratitude to a number of people who have contributed in various ways to the completion of this thesis. First of all, I would like to express my sincere gratitude to my supervisor, Professor Gerard L. Doorman, for his support, guidance and encouragement throughout the work on the thesis. Thank you for giving me the opportunity to be a part of your research group, and try a new and important adventure in my life. Your patient demeanour and kindness have been motivation enough to keep me going even when the going got tougher! I would also like to acknowledge my co-supervisor, Professor Olav Bjarte Fosso, for his caring attitude and valuable collaboration and discussions in every stage of this PhD work.

I would like to thank Ove S. Grande, the manager of the competence building project, “Balance Management in Multinational Power Markets”. Various project workshops and meetings have provided useful input to this thesis. The financial support from the project is gratefully acknowledged.

I greatly appreciate the cooperation with Magnus Korpås, Leif Warland, Daniel Huertas Hernando, and Harald G. Svendsen at SINTEF Energy Research. I acknowledge their assistance in using the PSST toolbox. Their continuous positive attitude up to and including the latest phase of the work is highly appreciated.

I look forward eagerly to further collaboration with them in my new career as a researcher at SINTEF Energy Research.

I am grateful to Vijay Venu Vadlamudi, Postdoctoral Fellow at NTNU, for his great support in writing the thesis. The readability of this thesis has improved a lot with his assistance.

The collaboration with PhD students Stefan Jeahnert at NTNU and Reinier van der Veen and Alireza Abbasy at Delft University of Technology was a great team work experience for me. We learned together and shared a lot of unique experiences. I acknowledge Stefan for the discussions at different stages of the work.

I would like to thank all of my colleagues at the power system group as well as my other friends for their friendship and support. We have shared some great moments together. I would also like to thank you for helping me during those last months to think of something other than just this thesis, if only for a few hours.

Raised in a culture which values education highly, I have always been encouraged by my parents to continue further in my studies. I sincerely thank them for all they have done for me, acknowledging that any amount of tributes to their unconditional love and sacrifices that have seen me thus far through the complex maze of life would be grossly underrated. I would like to thank my siblings for their support and love as well.

Last but not least, I would like to thank my beloved wife Nooshin for her love and support throughout these years. It would have been impossible for me to reach this crucial juncture of my life without her patience! This book is for you, Nooshin!

Hossein Farahmand  
Trondheim, June 2012

# Abstract

Maintaining a continuous balance between generation and load is crucial for the safeguarding of the power systems. In order to effectively deal with the various uncertainties that contribute to the real-time imbalance in liberalised power systems, Transmission System Operators (TSOs) procure and employ the so-called balancing services through balancing markets. In Europe, though such mechanisms are well in place at the national level, the potential of multinational balancing markets has not been fully exploited (with the exception of the Nordic system and various pilot projects). This thesis analyses the potential for integrating the balancing power markets in northern Europe, including the Nordic system, Germany and the Netherlands. It addresses the twin issues of the procurement and employment of cross-border balancing services by using mathematical models.

Beginning with an outline of the role of balancing markets in Europe, an overview of existing balancing markets in the northern European system is presented. A discussion on the cross-border balancing arrangements is then carried out, paving the way for quantitative analysis. A quantitative analyses of the multinational balancing markets are carried out, both in terms of attainable socio-economic cost savings, and their effect on the exchange of regional balancing services and generation dispatch. In this respect, two cases of balancing market integration are analysed: the current state with separate balancing markets, and the anticipated state of full integration of these markets.

In the proposed modelling approach a two-step model is used, representing the day-ahead and balancing markets, respectively. First, the day-ahead market is modelled as a common market for the whole European continent. Simultaneously, reserve procurement for northern Europe is modelled. Available transmission capacity is allocated implicitly to the balancing services exchange, based on the trade-off between day-ahead energy and balancing capacity exchange. Next, the balancing energy market is modelled as a real-time power dispatch on the basis of the day-ahead market clearing results and simulated imbalances. Detailed results

illustrate the consequences of market integration between two synchronous areas on procured and activated reserves, dispatch of generators, and power flows. The profitability of balancing market integration is quantified by the observed cost savings obtained due to the use of cheaper balancing resources and less activation of reserves caused by imbalance netting.

The implementation of cross-border balancing entails both qualitative and quantitative analyses of different balancing exchange scenarios. This thesis focuses on the qualitative studies of cross-border balancing arrangements together with the quantitative analysis of cross-border balancing. The methodology developed in the thesis enables the study of the benefits of integrating the northern European balancing markets, and the resulting exchange of balancing services among the Nordic countries, Germany and the Netherlands. The multinational balancing market can be adapted to capture the effect of different market integration scenarios. The presented modelling approach includes a flow-based market model, which takes into account physical power flows and loop flows, especially suitable for the European systems with highly meshed transmission grids.

A four tiered sequential approach is used to organize the primary contributions of the research work, as highlighted by the four distinct publications arising out of it.

- Tier 1: An optimal methodology for reserve activation in the Nordic system is established.
- Tier 2: Using the first tier as the basis, a cross-border reserves procurement algorithm is proposed for an integrated European system.

Superimposing Tier 2 on Tier 1 results in a bottom-up approach of capturing the full spectrum of reserve procurement and activation for integrated balancing markets.

- Tier 3: The profitability of balancing market integration is brought forward through both weekly and yearly analysis on the basis of mathematical models developed in Tier 1 and 2.
- Tier 4: It is shown that the flexibility concerns warranted by penetration of renewable energy resources can be well addressed by using the developed framework of cross-border balancing market integration. A case study of a future power system (in 2030) with wind energy penetration has been

employed in this regard.

The results include the optimal distribution of balancing reserve capacity allocations for procurement among the constituent countries, and the optimal exchange of balancing energy that ensues upon activating these capacity reserves.

An annual analysis of the post-integration scenario results demonstrates the significant cost savings that are achievable under the framework of multinational balancing markets.

The results also demonstrate the potential for increased production flexibility, in light of increased wind energy penetration in the future operation of power systems through the mechanism of multinational balancing markets.

# Abbreviations

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Abbreviation	
AC	Alternating Current
ACE	Area Control Error
ACOPF	AC Optimal Power Flow
AGC	Automatic Generation Control
ATC	Available Transmission Capacity
BALIT	Balancing Inter-TSO
BM-MBM	Balance Management in Multinational Balancing Market
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CHP	Combined Heat and Power
CWE	Central Western European
DCOPF	DC Optimal Power Flow
DK	Denmark
DK-E	Eastern Denmark
DK-W	Western Denmark
EC	European Commission
EEX	European Energy Exchange
EMPS	EFI's Multi-area Power Market Simulator
ENTSO-E	European Network for Transmission System Operators
EPEX	European Power Exchange
ERGEG	European Regulators' Group for Electricity and Gas
ETSO	European Transmission System Operator
EU	European Union
EUR	Euro (€)
EWEA	European Wind Energy Association
FADR	Fast Active Disturbance Reserve
FCDR	Frequency Controlled Disturbance Reserve
FCNOR	Frequency Controlled Normal Operating Reserve



Abbreviation	
FI	Finland
FRIEND	Flow Regimes from International Experimental and Network Data
GCC	Grid Control Cooperation
HVDC	High Voltage Direct Current
IDC-OPF	Incremental DC Optimal Power Flow
IFA	Anglo-French
LMP	Location Marginal Prices
LP	Linear Programming
LPX	Leipzig Power Exchange
LT-SES	Long-Term Security of Electricity Supply
MoU	Memorandum of Understanding
NE	Northern Europe
NGC	National Grid Company
NL	The Netherlands
NO	Norway
NOIS	Nordic Operational Information System
NTC	Net Transfer Capacity
NVE	Norwegian Water Resources and Energy Directorate
OPF	Optimal Power Flow
PI	Proportional Integral controller
PSST	Power System Simulation Tool
PTU	Program Time Unit
RG-CE	RG Continental European
RKOM	RKopsjonsmarkedet
RTE	Réseau de Transport d'Electricité
SARIMA	Seasonal Auto Regressive Integrated Moving Average
SDF	Stochastic Dynamic Programming
SE	Sweden
ST-SES	Short-Term Security of Electricity Supply
STU	Scheduled Time Unit
SvK	Svenska Kraftnät
TLC	Trilateral Market Coupling
TSO	Transmission System Operator
UK	United Kingdom
US	United States
VDN	Verband Deutscher Netzbetreiber

# Nomenclature

## Superscript

$d$  day-ahead dispatch

$hvdc$  HVDC cables

$hyd$  hydro units

$r$  real-time dispatch

$rat$  rationing

$th$  thermal units

$Tr$  transmission lines

## Indices

$\tau$  hour during the year

$a, b$  balancing regions

$a', b'$  balancing areas

$g$  thermal generators

$gr$  thermal regulating generators

$h$  hydro generators

$i, j$  buses in the system

## Sets

$BA$  set of balancing areas

$BR$  set of balancing regions

*Bus* set of buses in the system

*Bus<sub>a'</sub>* set of buses in the balancing area *a'*

*Bus<sub>a</sub>* set of buses in the balancing region *a*

*G* set of thermal generators

*GR* set of regulating resources

*H* set of hydro generators

*HVDC* set of HVDC interconnections

*Line* set of AC transmission lines

*T* set of simulation hours

**Parameters**

$\overline{C}_{h,\tau}^{hyd,r}, \underline{C}_{h,\tau}^{hyd,r}$  marginal cost of upward and downward regulation of hydro unit *h* at time step  $\tau$  in real-time dispatch, respectively (EUR/MWh)

$\overline{C}_{g,\tau}^{th,r}, \underline{C}_{g,\tau}^{th,d}$  marginal cost of upward and downward regulation of thermal unit *g* at time step  $\tau$  in real-time dispatch, respectively (EUR/MWh)

$\overline{P}_{ij}^{hvdC}$  maximum transmission capacity of HVDC cable from bus *i* to bus *j* (MW)

$\overline{P}_h^{hyd}, \underline{P}_h^{hyd}$  maximum and minimum available generation capacity of hydro unit *h*, respectively (MW)

$\overline{P}_g^{th}, \underline{P}_g^{th}$  maximum and minimum available generation capacity of thermal unit *g*, respectively (MW)

$\overline{P}_{ij}^{Tr}$  maximum transmission capacity of AC line from *i* to *j* (MW)

$\overline{Re}_{a'}$  upward reserve requirement for balancing area *a'* (MW)

$\overline{Re}_a$  upward reserve requirement for balancing region *a* (MW)

$\tilde{P}_{i,\tau}^{dev}$  real-time imbalance at bus *i* at time step  $\tau$  (MW)

$\underline{Re}_{a'}$  downward reserve requirement for balancing area *a'* (MW)

$\underline{Re}_a$  downward reserve requirement for balancing region *a* (MW)

$B_{ij}$  susceptance between buses *i* and *j* ( $\mathcal{U}$ )

## Nomenclature

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- $C_{h,\tau}^{hyd,d}$  marginal cost of hydro unit  $h$  at time step  $\tau$  in day-ahead dispatch (EUR/MWh)
- $C^{rat}$  rationing cost (EUR/MWh)
- $C_g^{th,d}$  marginal cost of thermal unit  $g$  in day-ahead dispatch (EUR/MWh)
- $C_{s_g}^{th,d}$  start-up cost of thermal unit  $g$  (EUR)
- $L_\tau$  length of time step  $\tau$  (hour)
- $NTC_{ab}$  NTC (Net Transfer Capacity) from balancing area  $a$  to  $b$  (MW)
- $P_{i,\tau}^L$  demand at bus  $i$  at time step  $\tau$  (MW)
- $Q_{h,\tau}^{hyd,d}$  inflow to reservoir of hydro unit  $h$  at time step  $\tau$  in day-ahead dispatch (MWh)
- $Rl_{h,\tau}^{hyd,d}$  reservoir level of hydro unit  $h$  at time step  $\tau$  in day-ahead dispatch (MWh)

### Variables

- $\Delta \bar{P}_{h,\tau}^{hyd,r}$  upward regulation of hydro unit  $h$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \bar{P}_{i,\tau}^{hyd,r}$  upward regulation of hydro units at bus  $i$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \bar{P}_{gr,\tau}^{th,r}$  upward regulation of thermal unit  $gr$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \bar{P}_{i,\tau}^{th,r}$  upward regulation of available thermal units at bus  $i$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \underline{P}_{h,\tau}^{hyd,r}$  downward regulation of hydro unit  $h$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \underline{P}_{i,\tau}^{hyd,r}$  downward regulation of hydro units at bus  $i$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \underline{P}_{gr,\tau}^{th,r}$  downward regulation of thermal unit  $gr$  at time step  $\tau$  in real-time dispatch (MW)
- $\Delta \underline{P}_{i,\tau}^{th,r}$  downward regulation of thermal units at bus  $i$  at time step  $\tau$  in real-time dispatch (MW)

- $\delta_{i,\tau}^d, \delta_{i,\tau}^r$  voltage angle of bus  $i$  at time step  $\tau$  in day-ahead dispatch and real-time dispatch, respectively (in radians)
- $F_{\tau}^d(\cdot), F_{\tau}^r(\cdot)$  cost function of day-ahead and real-time dispatch, respectively (EUR)
- $imp_{ab,\tau}^{dw,d}$  implicit allocated transmission capacity for downward regulating reserve exchange from balancing area  $a$  to  $b$  in day-ahead dispatch (MW)
- $imp_{ab,\tau}^{up,d}$  implicit allocated transmission capacity for upward regulating reserve exchange from balancing area  $a$  to  $b$  in day-ahead dispatch (MW)
- $P_{ij,\tau}^{hvdc,d}$  exchange energy on HVDC interconnection from  $i$  to  $j$  (MW) at time step  $\tau$  in day-ahead dispatch  $\tau$  (MW)
- $P_{h,\tau}^{hyd,d}$  production of hydro unit  $h$  at time step  $\tau$  in day-ahead dispatch (MW)
- $P_{i,\tau}^{hyd,d}$  hydro power production at bus  $i$  at time step  $\tau$  in day-ahead dispatch (MW)
- $P_{i,\tau}^{rat}$  load rationing at bus  $i$  at time step  $\tau$  (MW)
- $P_{g,\tau}^{th,d}$  production of thermal unit  $g$  at time step  $\tau$  in day-ahead dispatch (MW)
- $P_{i,\tau}^{th,d}$  thermal power production at bus  $i$  at time step  $\tau$  in day-ahead dispatch (MW)
- $P_{ij,\tau}^{Tr,d}, P_{ij,\tau}^{Tr,r}$  exchange power on AC transmission link between buses  $i$  and  $j$  at time step  $\tau$  in day-ahead and real-time dispatch, respectively (MWh)
- $St_{g,\tau}^{th,d}$  approximate relative start-up cost of thermal unit  $g$  at time step  $\tau$  in day-ahead dispatch,  $\in[0,1]$
- $X_{1,g,\tau}^{th,d}$  per unit production between 0 and the minimum production of thermal unit  $g$  at time step  $\tau$  in day-ahead dispatch,  $\in[0,1]$
- $X_{2,g,\tau}^{th,d}$  per unit production between the minimum and the maximum production of thermal unit  $g$  at time step  $\tau$  in day-ahead dispatch,  $\in[0,1]$
- $X_{3,g,\tau}^{th,d}$  per unit share of spinning reserve capacity of thermal unit  $g$  at time step  $\tau$  in day-ahead dispatch,  $\in[0,1]$

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# Chapter 1

## Introduction

Electric power plays an essential role in modern society, indispensable to technological growth in all spheres. A sample illustration of the heavy dependence of societal needs on electricity is shown in Table 1.1, which depicts the consequences of recent black-outs in Europe.

A power system is comprised of the three distinct functional zones of generation, transmission and distribution. The (generation) producers are on the top, and the consumers are located at the bottom of the electricity system chain. Transmission networks connect these two segments by transporting electricity along the high-voltage networks, and subsequently the low-voltage distribution lines. One of the distinguishing features of power systems is that electricity cannot be efficiently stored, save for smaller quantities. Hence, there must be instantaneous balance between supply and demand. This feature has had a determining impact on the structure and organization of power systems. Over time, as driven by the imposed liberalization policies in the electricity industry, traditional power system structures with vertically integrated hierarchies have given way to more deregulated forms of organization. In the emerging scenario, a close co-ordination between the operators of the electricity network and the producers of electricity is mandated to balance supply and demand, so that a safe and reliable supply of electricity to consumers is ensured. In the liberalised electricity industry, the energy transactions are cleared a priori, in advance of the real-time energy delivery based on the forecasted load and production estimates. The resulting forecasting errors will impose real-time imbalances in the power system. In this connection, the system operator must procure and employ enough *balancing services* to maintain the real-time generation-load balance.

Table 1.1: Examples of blackouts in the European power system [1]

Country, year	Consequences	Number of end-users interrupted
Sweden/Denmark, 2003	Loss of all lines and generation; separation of Southern Sweden/Denmark; voltage collapse	0.86 million in Sweden and 2.4 million in Denmark
France, 1999	Extensive outages; 0.4 % of the total network length damaged	1.4-3.5 million, 193 million $m^3$ wood damaged
Italy/Switzerland, 2003	Collapse of the entire Italian electric power system	55 million
Sweden, 2005	Extensive damage of overhead lines in Southern Sweden	0.7 million, 70 million $m^3$ wood damaged
Central Europe, 2006	Disturbances in the whole interconnected grid in Europe	15 million households

Balance management is the continuous balancing between production and consumption, and is a crucial aspect for the security of power supply. The first requirement for a synchronous interconnected power system like the European system is that the system shares the same nominal frequency. When loads in the system suddenly increase, generators slow down slightly, giving up some of their mechanical energy of rotation to supply the additional electrical energy required. In contrast, when loads suddenly decrease, generators speed up. Changing the speed of generators results in frequency deviations in the system. In case of a large frequency deviation, the frequency protection relays in the power system network sense the large deviation, and automatically initiate load shedding or tripping some of the interconnected transmission lines to disconnect the affected area. In extreme cases, frequency divergences can damage the system components or destabilise the power system, resulting in harmful consequences such as system black-outs [2].

Sufficient back-up services must be accessible to the system operators to maintain the generation-load equilibrium. When needed, calling upon these balancing reserves will ensure that continuous and near instantaneous balance between pro-



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duction and consumption of electrical energy is maintained [2]. Procurement and employment (activation) of balancing reserves are the two main tasks in system balance management. Since the liberalization of the European electricity industry, Transmission System Operators (TSOs)<sup>1</sup> have been responsible for the implementation of these two tasks to run a secure and reliable system. In this respect, TSOs procure balancing reserves well in advance of real-time energy delivery, and employ them effectively for compensating any real-time imbalances.

The more generators and motors there are coupled to the grid, the more stored kinetic energy the system will have. Therefore, system interconnection increases the inertia of the system, which increases the robustness of the system in case of a disturbance. In the moments following a disturbance, all control areas contribute to compensating the generation-load imbalance based on the principle of solidarity. According to [3], solidarity means control areas assist each other in the event of disturbances. However, interconnecting the power systems has the downside such that a frequency deviation in one part of the system might lead to the propagation of a disturbance throughout the interconnected system. Although frequency could be temporarily “stabilised” with assistance from neighbouring areas, it is the responsibility of the TSO of the imbalance-originating area of the system to initiate corrective actions for “restoring” the frequency in his area through the activation of procured reserves [4]. Stabilisation of frequency through solidarity based exchanges is only a buffer, and the onus is on the TSO of the imbalance-originating area to take explicit measures of not only restoring nominal frequency in his area through reserve activation, but also transmitting back the energy received during the stabilisation process to the adjacent areas. Failure to do so would endanger the over-all system security of electricity supply. The above mentioned description is the underlying feature of “decentralised” system balancing. This is mostly in vogue in the present European context. However, migrating to a more “centralised” system balancing, where all the TSOs coordinate to help the TSO in need, is a more amenable solution to maintaining the system integrity.

Figure 1.1 shows the European interconnected grid system [5]. The Continental European region is a synchronous interconnected system connecting all national systems from Portugal to Turkey. It has a 631 GW generation capacity, serving 450 million customers. The region of UK and Ireland (with a combined generation capacity of 85 GW), the Baltic region (337 GW generation capacity), and the Nordic region (94 GW capacity) are asynchronously connected to Continental Europe via High Voltage Direct Current (HVDC) cables. In the event of

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<sup>1</sup>In the European countries, the system operators are also responsible for the high-voltage grid (the transmission grid), therefore system operators are called “Transmission System Operators” (TSOs).

frequency disturbances in these individual regions, these systems operate separately from the affected region, i.e., HVDC interconnections act as barriers from distributing the effects of frequency fluctuation [5].

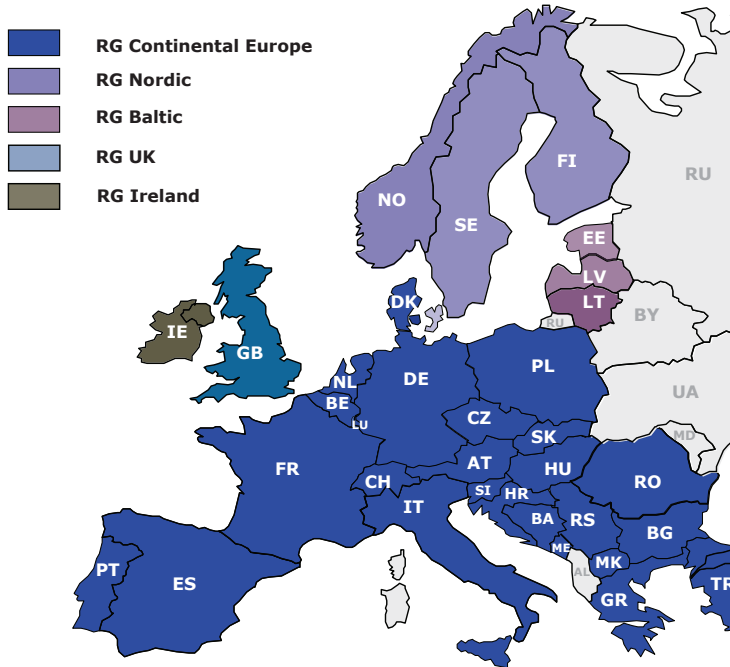


Figure 1.1: European interconnected system [5]

After decades of decentralised system balancing in Europe, a tendency towards increasing cooperation and coordination among the TSOs for centralised balance management is gradually on the rise. One example is the Nordic system, which includes Norway, Sweden, Denmark and Finland. The balancing market within the Nordic system has already been integrated, and has been in the process of further harmonisation since 2009 [6]. The balancing services can be freely exchanged between the Nordic countries, where, irrespective of nationality, the cheapest balancing resource has been selected in the common balancing market. Some examples of international balance management in continental Europe are presented in Chapter 4. However, the cross-border exchange of balancing reserves can also be effectively implemented between asynchronous systems, as witnessed between western Denmark and the Nordic system [7]. The premise for this thesis

is derived from this promising approach. It simulates a proposed cross-border balancing mechanism between the Nordic region and the region of Continental Europe.

## 1.1 Problem definition

This work is a contribution to the research project “*Balance Management in Multinational Power Markets*”<sup>2</sup> (BM-MPM). The BM-MPM project is a joint venture by SINTEF Energy Research, the Department of Electric Power Engineering at the Norwegian University of Science and Technology, and the Department of Technology, Policy and Management at the Delft University of Technology. The project is funded by the Norwegian Research Council (1784677/S3), the Next Generation Infrastructure Foundation in the Netherlands, the Norwegian and the Dutch TSOs (Statnett and TenneT TSO B.V.), the Norwegian power producers (Statkraft, BKK, Sira Kvina, and Agder Energi), the Norwegian Water Resources and Energy Directorate (NVE), and GDF Suez in Belgium. The overarching interest of the project is balancing market integration and harmonisation. The main objective of the project is stated as [8]:

*“To design the scientific foundation for a framework for efficient, market-based balancing of power systems that can be implemented in multinational power markets.”*

The focus of the project is to investigate the possible mechanisms for the exchange of balancing services among the individual balancing markets in the northern European area, including the Nordic system, Germany and the Netherlands. Figure 1.2 shows the northern European area including two different synchronous interconnected systems, i.e., the Nordic system (except western Denmark), and the other North-European countries which are synchronous with the region of Continental Europe. The figure also depicts the Alternating Current (AC) and HVDC interconnections between the countries. More details of the northern European power markets are presented in Chapter 3. The purpose of the research project is to analyse the potential for reducing total costs involved in the real-time balancing in the individual countries through integration and harmonization of the aforementioned systems. Sharing the balancing resources may improve the overall system reliability and security of supply through the increased availability of reserves, allowing for more production flexibility. Furthermore, integration of balancing markets is expected to create additional business opportunities for both TSOs and power producers to increase the value of their assets.

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<sup>2</sup><http://www.sintef.no/balance-management>

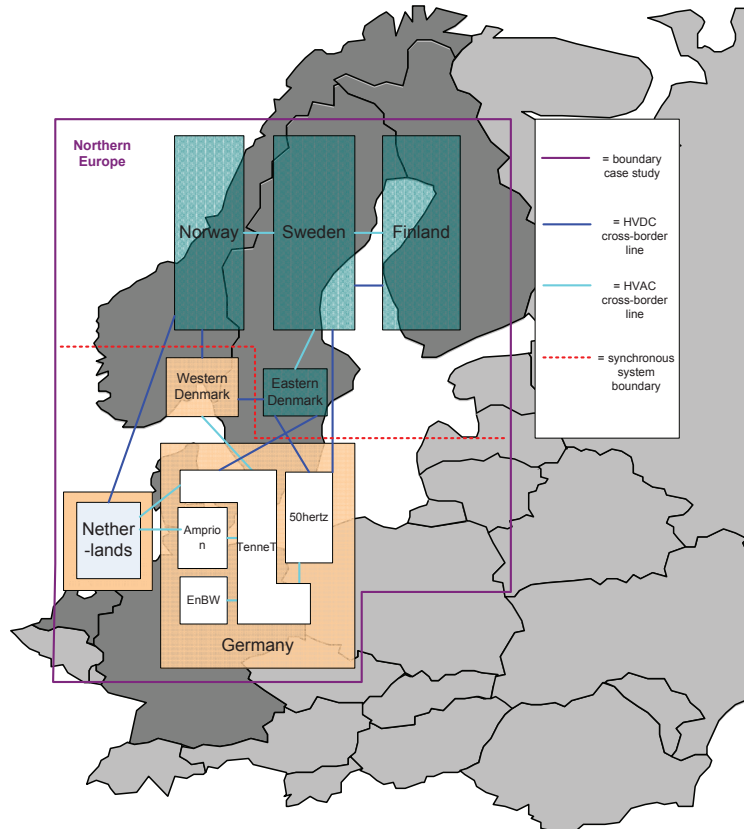


Figure 1.2: The northern European power grid

The integration of balancing markets is a broader research area. However, in line with the project plan [8], the research focus in the BM-MPM project is restricted to addressing selected challenges in the following issues:

### 1.1.1 Technical issues

- (i) The capacity of the interconnecting link constrains the physical exchange of power between the connected systems. If reserve capacity is procured outside the control area, then enough transmission capacity must be avail-

able on the link to transfer the real-time balancing energy. This entails cross-border capacity exchange studies that analyse the trade-off between the amount of capacity to be allocated for reserve procurement and the capacity to be allocated for day-ahead scheduling.

- (ii) The hydrological situation of the system can highly affect the availability of balancing resources in hydro dominated systems, in turn affecting the distribution of balancing resources.
- (iii) The coordination and cooperation of different control technologies in the reserve activation is a challenge in multinational balancing markets.

### 1.1.2 Economic issues

- (i) The extent of balancing market integration is believed to be correlated to the envisaged cost savings.
- (ii) The integrated balancing market should provide incentives for the market parties to encourage their participation.
- (iii) The allocation of costs and benefits, and re-distribution of balance management costs between market parties, are the primary economic challenges.

### 1.1.3 Institutional issues

- (i) The design of multinational balancing markets must take into account the institutional arrangements in the participating countries. Since the characteristics of different national markets are different, determining the levels of harmonisation and integration among balancing elements is a key institutional challenge.
- (ii) Different performance criteria should be examined for different market arrangements to find the best multinational balancing market arrangement.

This part of the research has been carried out by research partners at the Delft University of Technology. The outcome of their research will be discussed in Section 4.3. The present thesis work is aimed at addressing issue no.(i) of the technical issues described in Section 1.1.1 and issue no.(i) of the economic issues described in Section 1.1.2.

## 1.2 Motivation

The practical implications of the research goals outlined in the above-stated problem statement could be gauged from the following motivators. The study of the exchange of balancing services among the Nordic system, Germany and the Netherlands is of particular interest as follows:

- As stated earlier, one of the principal drivers for the development of multinational balancing markets is the desire to reduce the total cost involved in real-time system balancing through the sharing of resources between individual balancing markets. There is also the added advantage of increasing the production flexibility in individual markets. Hydro generation has ideal characteristics for providing balancing reserves in comparison to thermal generation. This is due to its high regulation speed and low operating cost. More than 50% of the power generation in the Nordic area is due to hydropower; therefore, the Nordic hydro plants with their large reservoirs are ideal candidates to facilitate the provision of balancing reserves.
- Apart from the existing HVDC interconnection between the Nordic and the central European systems, there are new HVDC interconnections on the anvil. The ongoing HVDC interconnection between Norway and Germany (NorGer cable), and the planned HVDC interconnections between Norway and the UK (Norway-UK cable) as well as Denmark and the Netherlands (CORBA cable) leave room for more cross-border exchange of balancing services [9].
- It is anticipated that the need for balancing reserve will increase on account of the increased production uncertainty due to the rapid expansion of renewable energy resources such as wind energy. The European Wind Energy Association's (EWEA) proposal of high wind scenario has an estimated target of 265 GW capacity of wind energy for 2020, out of which more than 30% will be in the northern European system [10]. The balancing market integration will increase the production flexibility that can also account for the intermittency of the renewables.

## 1.3 Scope of the PhD work

The thesis aims to develop the requisite knowledge of the technical aspects of multinational balancing markets for the northern European area. More specifically, the research is targeted towards developing a fundamental framework for

evaluating the distribution of balancing resources in each control area. Distribution of balancing resources is defined as the optimal allocation of reserve capacity. This capacity is supposed to be “procured” from:

- (a) The existing multinational balancing markets within the Nordic system, and/or
- (b) The advocated multinational balancing markets outside of the Nordic system.

The key contribution of the thesis is the mathematical modelling of the multinational exchange of balancing services in a combined pool of Norway, Germany, and the Netherlands, taking into account transmission constraints on both the AC grid and the interconnecting HVDC links.

Detailed studies have been carried out on two levels of balancing market integration to demonstrate the conceptual formulations. These studies include the current state of the system, with no possibility of exchanging balancing services between the Nordic and the RG Continental European systems, and the full integration of these balancing markets. In this connection, the following studies have been carried out:

- The consequences of balancing market integration are studied in terms of operational cost savings.
- The effects of market integration on the procurement and the activation of balancing services of each control area are investigated.
- In order to realistically capture the underlying physical phenomenon of power transfers, necessary incorporations have been made to suitably modify the existing models, e.g., PSSST, SecOpt (see Chapter 5) for implementation.

In addition to the exchange between the Nordic system, Germany and the Netherlands, a future system with offshore grid configuration [10], with a high share of intermittent generation, has been studied in the context of implementing the proposed balancing market integration.

Though the thesis principally deals with integration issues, some aspects of the harmonisation of balancing markets have also been touched upon.

The following underlying assumptions are used in the research work:

- The market is modelled as a perfect market, and all generators are price takers.

- Generators bid their marginal costs.
- Market power is non-existent.
- Day-ahead market clearance and reserve capacity procurement are done simultaneously.
- The market model accounts for stationary behaviour of reserve activation, i.e., the dynamic behaviour is neglected. It means that the effect of intermediate control actions such as primary control and transient disturbances has been neglected.
- The imbalances in each control area are assumed to be completely compensated within each time resolution of the balancing market. The system dynamic behaviour within each of the time frames has not been taken into account.
- The objective of the balancing activation is purely to relieve imbalances while minimizing the balancing costs, and not to do an optimal re-dispatch.

## 1.4 Contributions

The concept of multinational balancing markets has begun to receive considerable attention in Europe as can be seen from the proliferation of studies from European institutions like ERGEG, ACER, ENTSO-E, Eurelectric and others. (Section 4.3 expounds more on the findings of the literature survey.) A majority of the existing focus seems to have been on the economic consequences of market integration and the accompanying institutional aspects of multinational balancing market design. Limited attention has been given to addressing the technical issues in balancing markets. With this research gap in mind, a new market model for balancing services is proposed, encompassing the scope presented in the preceding sub-section. The work presented in this thesis contributes towards improved modelling of day-ahead and real-time balancing markets for a large scale power system, i.e., the continental European power system. The main contributions are listed as follows:

- A mathematical model for a common day-ahead spot market for the whole European power system has been developed. This model includes the balancing capacity reserve requirements for the northern European power system as a vital constraint. DC optimal power flow (DCOPF) is used in the proposed model, with the objective to minimise the total operating costs



for the next 24-hour (24-h) period. Cross-border interconnection capacities are implicitly allocated to the reserve exchange based on the trade-off between energy and reserve capacity exchanges. Since the size of the optimisation problem is extremely large, an LP based approximate algorithm is introduced to consider the start-up costs of generators to avoid excessive calculation times.

- A second mathematical model for incremental real-time power dispatch in the balancing markets is introduced on the basis of results obtained from the above model. The aim of this model is to have a result aligned as closely as possible with the day-ahead dispatch result from the above model. This means that there is no full re-dispatch in real-time, which would have a cost decreasing effect but which does not correspond to the present European market design. DCOPF is also used here with the objective of minimising the cost of compensating for deviations from the initial market equilibrium conditions.
- An enriched modelling of hydro system representation is employed in the above models. The marginal costs of utilising hydro power for every individual reservoir within the interconnected systems is identified for strategic deployment of hydro reservoir levels. To capture the dynamic effects of low load and high load conditions in the system, start-up costs of thermal generators have been taken into account. The start-up costs of hydro generators are deemed negligible.

The insights gained from implementing these models on detailed case studies are presented, along with their consequent implications for both the existing and future systems.

Dissemination of these research contributions are presented in the following publications:

- **Paper I:** *Flow Based Activation of Reserves in the Nordic Power System*, H. Farahmand, S.M.A. Hosseini, G.L. Doorman, O.B. Fosso, IEEE PES General Meeting 2010, Minneapolis, USA, 25-29 July 2010.
- **Paper II:** *Modelling of Balancing Market Integration in the Northern European Continent*, H. Farahmand, G.L. Doorman, 17th Power System Computation Conference (PSCC 2011), Stockholm, Sweden, 22-26 August, 2011.
- **Paper III:** *Balancing Market Integration in the Northern European Continent*, H. Farahmand, G.L. Doorman, Applied Energy (2011), doi:10.1016/j.apenergy.2011.11.041.

- **Paper IV:** *Balancing Market Integration in the Northern European Continent: A 2030 Case Study*, H. Farahmand, G.L. Doorman, T. Aigner, M. Korpås, D. Huertas-Hernando, accepted for publication in IEEE Transactions on Sustainable Energy- special issue on application of wind energy to power system.

The research work also resulted in four additional publications, that are outside the main scope of this thesis:

- **Paper V:** *Modelling of Prices Using the Volume in the Norwegian Regulating Power Market*, S. Jaehnert, H. Farahmand, G.L. Doorman, 2009 IEEE Bucharest PowerTech Conference, Bucharest, Romania, 28 June-2 July 2009.
- **Paper VI:** *Optimal Wind Farm Bids Under Different Balancing Market Arrangements*, K.W. Ravnaas, H. Farahmand, G.L. Doorman, IEEE 11th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), pp.30-35, Singapore, 14-17 June 2010.
- **Paper VII:** *Impact of System Power Losses on the Value of an Offshore Grid for North Sea Offshore Wind*, H. Farahmand, D. Huertas-Hernando, L. Warland, M. Korpås, H.G. Svendsen, , 2011 IEEE Trondheim PowerTech Conference, Trondheim, Norway, 19-23 June 2011.
- **Paper VIII:** *Impact of Reserve Market Integration on the Value of the North Sea Offshore Grid Alternatives*, Y. T. Gebrekiros, H. Farahmand, G.L. Doorman, 9th International Conference on the European Energy Market (EEM12), Florence, Italy, 10-12 May 2012.

## 1.5 Thesis structure

This chapter has defined the problem to be solved in this PhD research. It outlines the motivation and scope of, as well as the important contributions to, the field of research. The remainder of the thesis is organised as follows:

**Chapter 2** provides the background for the work. The chapter describes the following concepts: security of electricity supply, markets for balancing services, principles of balancing control and balancing control terminologies. The chapter concludes with the principle of the model used for the exchange of balancing reserve between non-synchronous control areas.

**Chapter 3** presents an overview of the northern European power markets. The chapter describes the current practices employed in the Nordic, German and

Dutch systems for the procurement and employment of balancing services.

**Chapter 4** introduces the cross-border trading model and the various concepts proposed by the European organisations, followed by the concept of implicit and explicit auctions implemented in the current market coupling models. Additional information on the existing balancing market integration in continental Europe is presented. This chapter also includes the relevant literature survey on the concepts and existing proposals of integrated balance markets.

**Chapter 5** describes the methodologies employed in the research.

**Chapter 6** presents an overview of the publications arising from the research, explaining the contributions of each individual paper, and concluding with the overall contribution of the publications to the field of study.

**Chapter 7** presents conclusions from the results obtained in this thesis, and the scope for future work.

## Chapter 2

# Background and Concepts

In this chapter, the basic background of the research is presented. The first part of the chapter provides a perspective on the significance of balancing services in ensuring the security of electricity supply. The scope is then narrowed down to the basics of balancing markets and the associated interaction between the various market players. Subsequently, there is a discussion of the different control strategies employed to achieve the system balancing, and the relevant terminologies used in the northern European area. The sections are briefly outlined as follows. Section 2.1 provides a short overview on the contribution of balancing services to the security of electricity supply, and the different types of balancing services. Section 2.2 describes the basics of markets for balancing services. In Section 2.3, the principle of balancing control, and the different balancing control methods in the northern European area, are presented.

### 2.1 Security of Electricity Supply

*“Security of electricity supply is the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner, relating to the existing standards and contractual agreements at the points of delivery.”* [11]

Ensuring the security of supply is a high priority in the electricity industry. There has been a significantly increasing interest in the security of supply, particularly since the blackouts in Europe during 2003. Directive 2005/89/EC of the European Parliament,<sup>1</sup> and its subsequent revision by the Council of the Euro-

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<sup>1</sup>[http://europa.eu/legislation\\_summaries/energy/external\\_dimension\\_enlargement](http://europa.eu/legislation_summaries/energy/external_dimension_enlargement)

pean Union on 18 January 2006, concerns measures to safeguard the security of the electricity supply and the infrastructure investments. The Directive's purpose was to establish measures to:

- Ensure an adequate level of generation capacity
- Guarantee an adequate balance between supply and demand
- Set up an appropriate level of interconnection between the EU countries

Moreover, the Directive also establishes a framework in which the EU countries are to define policies on the security of electricity supply compatible with the internal markets for electricity [12].

Generally, the security of electricity supply can be studied under two main classifications: Long-Term Security of Electricity Supply (LT-SES) and Short-Term Security of Electricity Supply (ST-SES). LT-SES concerns the simultaneous adequacy of the resources and infrastructure, which is beyond the scope of this thesis.

A concise distinction between “adequacy” and “security” was elaborated by Billinton *et al.* [13], with respect to the classification of power system reliability studies. Power system reliability studies are categorized into two domains: Adequacy and Security. The examination of sufficient facilities within the system to satisfy the consumer load demand and system operational constraints, constitutes an adequacy analysis, and is associated with static conditions that do not include system dynamics and transient disturbances (which form the basis of security analysis). System adequacy precedes system security. Further, system security studies could be done under two classes: transient (dynamic) and steady-state (static). ST-SES can be interpreted as an operational security requirement needing adequate technical back-up and proper market framework. This arrangement would enable the system operator to procure the services required to keep the balance between supply and demand at any moment of operation intact.

Due to the non-storable property of electrical energy, power systems must maintain a continuous and near-instantaneous balance between generation and load. In response to a power imbalance, the stored rotational kinetic energy in turbines is released to compensate for the imbalance energy, resulting in an inherent reduction in system frequency. Maintaining the frequency at its target value requires that produced and/or consumed active power be controlled in order to maintain equilibrium. A certain amount of active power, usually called frequency

control reserve or balancing service, is kept available to perform this control action. Therefore, balancing services are essentially ancillary services, providing a back-up capability for the power system to compensate for the mismatch between supply and demand. The availability of sufficient balancing services can make the power systems reliable, and the electricity market transactions deliverable [14]. There are also other services such as voltage support and reactive power services to maintain the system voltage levels, which are out of the scope of this thesis. These services, together with balancing services, collectively comprise “ancillary services” [15].

## 2.2 Market for Balancing Services

In the European liberalised electricity systems, introduced in the early 90’s, the task of the secure and reliable operation of the power system falls in the hands of the TSO. Thus, it is the responsibility of the TSO to employ a suitable mechanism to balance the system. In order to fulfil its obligations, the TSO needs to procure balancing services and employ them in the case of imbalance. The required services can be in the form of the generation of resources and dis-connectible loads that are able to adjust their production and consumption, respectively, in real-time on short notice.

Before liberalisation, balancing reserves were maintained by the centralised utilities at a level high enough to confidently ensure supply security. The costs of this safety margin were passed through to consumers. With the introduction of competition, producers in the de-centralised environment are willing to provide reserves only if they are adequately compensated. Placing obligations on producers to maintain certain reserves would, on the one hand, conflict with the principles of a competitive market and, on the other hand, may entail day-ahead market distortions. E.g., the producers’ bid can be biased by the obligatory reserve assigned to them, and the energy market will not be truly cost reflective. Therefore, in the European deregulated markets, reserve adequacy can be best ensured only through appropriate market mechanisms, guided by commercial contracts for reserves [11]. The purpose of balancing markets is to provide a framework for guaranteeing system security at minimum socio-economic costs.

A balancing market can be viewed as a platform to implement balance management in the liberalised power systems. It generally consists of three main players: TSOs, Balancing Service Providers (BSPs), and Balance Responsible Parties (BRPs). BSPs provide balancing services to TSOs, and TSOs procure and employ these reserve services to safeguard and restore real-time balance in

the system. In the procurement phase, BSPs submit balancing bids to the TSO. In the employment phase, the TSO activates the bids according to the needs of the power system. BSPs are paid for their services in the settlement phase. Real-time dispatched energy is settled based on the balancing energy activated at each Scheduled Time Unit (STU), and real-time balancing prices are determined based on the amount of real-time dispatched energy and the bids of the BSPs. BRPs submit their plan for power production (including power for exchange with other BRPs) and/or consumption to the TSO in advance of the real-time energy delivery. Deviations from BRPs' announced generation and consumption schedules are charged with real-time balancing prices by the TSO. Thus, the balancing market is a platform where BRPs pay indirectly to BSPs for solving real-time imbalances through the TSO.

The TSO plays two key roles in running the balancing market - in procuring sufficient balancing service capacities, and in employing balancing services in the real-time operation of the system. This description is given as below [16]:

- Procurement of balancing services: TSOs procure options for balancing service capacities from BSPs through long-term payment mechanisms, which guarantee the availability of sufficient reserve in the real-time operation of the power system. Depending on the actual market arrangement for balancing services, TSO procures balancing services through mandatory impositions, bilateral contracts or an auctions market.
- Employment of balancing services: Any real-time imbalance in the system needs to be resolved by the relevant TSO. Therefore, the TSO takes the necessary remedial actions to balance the system with least cost measures, and charges BRPs for deviations from their submitted scheduled plans. The imbalance between contracted agreement and real-time requirements is settled through an ex-post mechanism. In the imbalance settlement mechanism, an imbalance price is calculated for each time resolution of the balancing market. The imbalance settlement is highly dependent on balancing market design, and could differ from one balancing market to another.

As shown in Figure 2.1, capacity and energy are traded in the balancing market through two distinct market places - balancing reserve capacity market and balancing energy market, respectively. The required reserve for each balancing area is determined by the system regulatory body based on the individual system's assessment of local requirements, network bottlenecks and fault tolerance (e.g., N-1 criteria <sup>2</sup> [17]) dimensioning. According to ENTSO-E recommenda-

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<sup>2</sup>"N-1 criteria are a way of expressing a level of system security entailing that a power

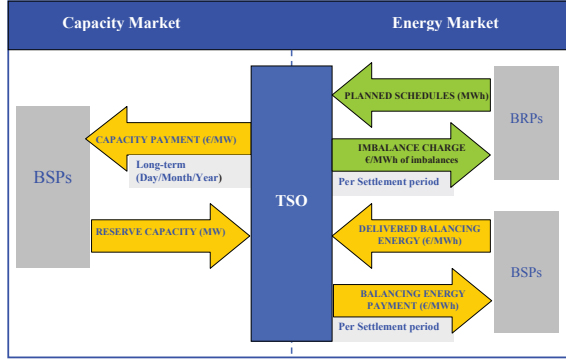


Figure 2.1: Balancing services procurement and employment in balancing capacity and energy markets

tion, the minimum reserve can be determined based on the following empirical formula without distinguishing between upward and downward reserves [4]. It is determined in proportion to the maximum anticipated load for the balancing area.

$$R_{req} = \sqrt{aL_{max} - b^2} - b \quad (2.1)$$

where,

$R_{req}$  is the recommendation for secondary control reserve (MW)

$L_{max}$  is the maximum anticipated load for the balancing area (MW)

$a$  and  $b$  are empirically established parameters.  $a = 10$  MW and  $b = 150$  MW for ENTSO-E.

As shown in empirical formula, required reserve is determined in proportion to the maximum anticipated load for the balancing area. However, a revision of the empirical formula seems to be warranted in future. This is so because the current formula only takes the maximum anticipated load into account. There must also be some appropriate factor to be considered to account for the production intermittency in the case of large scale wind production. The integration of large scale wind generation requires an increase in the amount of required reserve to maintain an acceptable level of reliability to balance generation and load. Despite the reduction of wind power variability as a result of improved wind forecast

*system can withstand the loss of an individual principle component (production unit, line, transformer, bus bar, consumption etc.)"*



methodologies and geographical wind smoothing, the variability and uncertainty of wind power generation tend to be a source of stress for the security of supply in future power systems [18].

The TSO procures the required balancing capacity in the capacity market. BSPs submit their bids for capacity payment and, in case of the selection of their bids, will be paid for utilising their offered services in the real-time balancing energy market. The balancing energy market is the market for balancing energy delivery. Depending on the real-time imbalance volumes *and/or* transmission restrictions, the TSO activates the required reserves. It must, however, be noted that in some market structures, the same balancing resource which is used for frequency control, could also be used to relieve congestion. However, in most market structures, balancing resources would not be used for congestion relief because the interference of congestion prices would result in the undesirable skewering of the imbalance prices for BRPs [19].

## 2.3 Principles of Balancing Control

Balancing control is the necessary counteracting mechanism to unwanted frequency deviations so as to restore balance between load and supply. The most important feature of balancing control is the response time including “start time” and “deployment time”. Start time is the maximum amount of time that can elapse between the request from the TSO and the beginning of response by the service provider. The maximum time that can elapse between the moment when the provider receives the request and when the full response is delivered is called the “full deployment time”. Depending on the response time of the control reactions, the European Network of Transmission System Operators for Electricity (ENTSO-E)<sup>3</sup> operation handbook regarding Load-Frequency Control [4] gives the following explanation of balancing control in the synchronous continental system.

- **Primary Control:** The objective is to maintain the balance between generation and consumption within the synchronous area, using turbine speed governors. This action is decentralized and aimed to re-establish the system balance after a disturbance or incident in the time frame of seconds, but without restoring the reference values of system frequency and power exchange. It means that the balance can be re-established at a system frequency other than the frequency set-point value of 50 Hz. This is called

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<sup>3</sup>[www.entsoe.eu](http://www.entsoe.eu)

a quasi-steady-state frequency deviation, as shown in Figure 2.2. The primary control start time is a few seconds, and the deployment time for 50% of the total primary control reserve is at most 15 seconds. From 50% to 100%, the maximum deployment time rises linearly to 30 seconds. To avoid calling up primary control in undisturbed operation or near nominal frequency, a static security margin of 20 mHz is defined. The quasi-steady-state frequency deviation in the synchronous area must not exceed  $\pm 180\text{mHz}$ , and the instantaneous frequency must not fall below 49.2 Hz or exceed 50.8 Hz, which is a defined margin of  $\pm 800\text{mHz}$ .

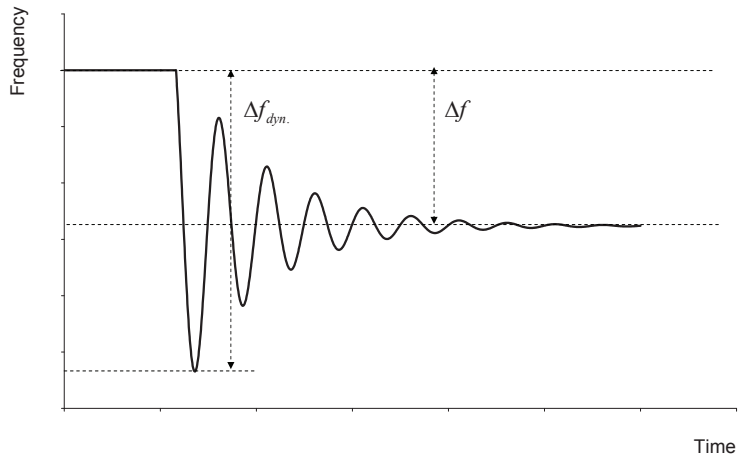


Figure 2.2: Quasi-Steady-State deviation after primary control action [4],  $\Delta f_{dyn}$  = Dynamic frequency deviation,  $\Delta f$  = Quasi-steady-state deviation

- **Secondary Control:** This is the centralised control to restore balance between generation and demand within the balance control area, and return the interchange between areas at the levels specified in the control program. The start time for this control is 30 seconds and must be fully deployed within 15 minutes. Secondary control uses centralized Automatic Generation Control (AGC), changing the active output set-point of select generators in order to restore the frequency and interchanges with other systems to the desired levels. Thus, contrary to the primary control action which limits and/or stops the frequency excursion, the secondary control brings the frequency back to its target value. Secondary control usually relies on a proportional integral (PI) controller to continuously bring back the Area Control Error (ACE) of the effected area to zero. The ACE is calculated as the sum of the exchange power control error and the frequency

control error times the frequency bias<sup>4</sup>. Secondary frequency control is not implemented in some power systems, where frequency is regulated using only automatic primary and manual tertiary controls, as in the Nordic system. However, it is used in all large interconnected systems because manual control does not remove overloads on the interconnection quickly enough.

- **Tertiary Control:** This control uses the tertiary reserve (15 minutes reserve) that can be usually activated manually by the TSOs after the activation of secondary control. It is used to free up the primary and secondary reserves, and manage congestion in the transmission network. It is also employed to bring the frequency and the interchanges back to their target values when the secondary control is unable to perform this task.

The time frame of control energy usage is shown in Figure 2.3.

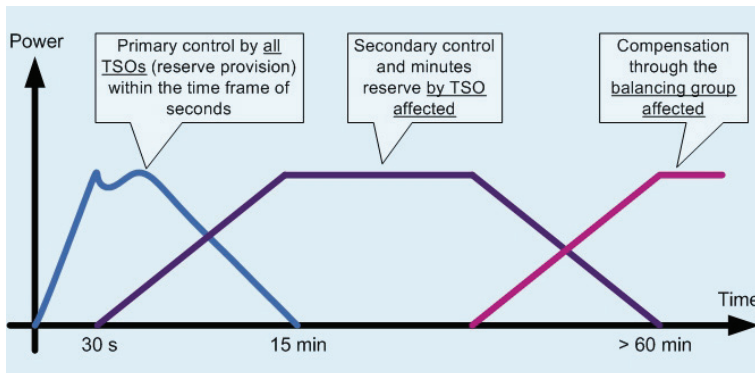


Figure 2.3: Time frame of control action usage in ENTSO-E

## 2.4 Balancing Control Terminologies

Depending on different generation portfolios, different types of balancing services and control arrangements are used by TSOs. Given the differences in generation portfolios in the northern European systems, different terminologies and control phases are defined in different ways in the control areas within these systems. In

<sup>4</sup>ACE can be formulated as  $ACE = \Delta P_{ex} + k_i \cdot \Delta f$ , where  $\Delta P_{ex}$  is net area exchange deviation (MW),  $k_i$  is frequency bias setting (MW/Hz), and  $\Delta f$  is system frequency deviation (Hz). The frequency bias setting is determined for an area based on its generators' speed-droop characteristics and load power-frequency characteristics [2].

the following sections, different terminologies used in the Nordic, German and Dutch systems are discussed and their relevance is explained.

### 2.4.1 Germany and the Netherlands

The German and the Dutch systems are a part of the continental system, and are using similar terminologies and control phases as in the ENTSO-E operation handbook. Germany follows the following control phases [20]:

- Primary control is an automatic reserve which is provided by way of solidarity by all the synchronously connected TSOs inside the continental European system. It is activated within 30 s, and the time period per single incident is between 0 and 15 *min*.
- Secondary control is a direct and automatic activation by the affected TSO. It has to be activated within 5 *min* and the time period per single incident is between 30 s to 15 *min*.
- Minutes control, also called tertiary control in the continental European context, is a response to the telephonic and schedule-based request from the affected TSO to the respective suppliers. The time period per single incident is from 15 *min* up to 4 quarter hours. It can also be up to several hours in the event of multiple disturbances.

The Netherlands uses the same terminology as the ENTSO-E operation handbook, i.e., primary, secondary and tertiary controls. These are applicable to both upward and downward regulation with a control speed of at least 7% of the unit capacity per minute. Each control has the same activation time as has been stated in the ENTSO-E operation handbook [17].

### 2.4.2 The Nordic system

While the continental system uses expressions such as primary, secondary and tertiary controls, different terminologies are used for balancing reserves in the countries across the Nordic system.

The Nordic system uses both the automatic and manual active reserves, which are divided into groups [7]: The automatic reserve is divided into Frequency Controlled Normal Operating Reserve (FCNOR) and Frequency Controlled Disturbance Reserve (FCDR). The manual active reserve is also known as Fast Active

Disturbance Reserve (FADR).

- FCNOR reserve is used for handling small frequency deviations during the “normal” operation. Frequency is usually allowed to float between 49.9-50.1 Hz, and the FCNOR reserve is fully activated at 49.9 Hz. The reserve shall be regulated upwards/downwards within 2-3 *min*. At least 2/3 of the reserve must be allocated from within the respective control area in case of grid splitting or islanding [7].
- FCDR reserve ensures that dimensioning faults<sup>5</sup> will not entail a frequency of less than 49.5 HZ in the synchronous system. 50% of the reserve shall be regulated upwards within 5 s and 100% within 30 s. As in the case of FCNOR, at least 2/3 of the reserve must be allocated from within the respective control area in case of grid splitting or islanding. In the event of frequency drops to 49.5 Hz, automatic load shedding, e.g., industrial and electric boiler consumption, can be counted as belonging to the FCDR reserves [7].
- FADR reserve is the manual reserve that must be available within 15 minutes following a contingency, and be allocated such that the system will be returned to normal operation. It also re-establishes the FCDR reserve. FADR reserves can be shared among the partners in the Nordic system, provided there is no potential congestion in the transmission system that might prevent the activation of reserves [7].

Comparing the different terminologies used in the Nordic and continental systems, the following correspondence could be concluded. FCNOR and FCDR correspond to primary control in the continental context, and FADR corresponds to the manually served tertiary control. In the Nordic system, secondary reserve using AGC is presently not in use (the exception is western Denmark, which belongs to the continental synchronous system), where imbalance regulation is performed using FCNOR, FCDR and manually activated FADR.

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<sup>5</sup>“Dimensioning faults are faults which entail the loss of individual major components (product units, line, transformers, bus bars, consumption etc.), and entail the greatest impact upon the power system from all fault events that have been taken into account [7].”

## 2.5 Exchange of Balancing Reserve Between Non-synchronous Control Areas

TSOs plan generation schedules from hours to months in advance, coordinating the production dispatch of generators and the power exchange with adjoining power systems based on factors such as weather prediction, historical load patterns, and maintenance schedules. Hydro and gas-fired power plants are generally used for generation regulation and load following. Nuclear plants and large coal-fired plants cannot be normally used for these purposes as they are not fast enough, and are more expensive than hydro and gas-fired power plants.

Depending on the balancing arrangement in each individual system, frequency is controlled in the time scale of minutes to seconds by AGC or fast active reserves, which control the real power output of certain generators that are able to respond rapidly to changes in load.

The basic geographical unit of a power system is the control area, which typically has a single control centre responsible for monitoring system conditions and scheduling the dispatch of all generation. In the interconnected systems, transmission lines to neighbouring control areas are metered, and the incoming and outgoing power flows are scheduled and continuously monitored. Thus, ACE is a control signal to real-time corrections to maintain load-generation balance. In an interconnected system, except where DC links are used, frequency restoration must be accomplished through the above control arrangements. However, in two interconnected non-synchronous control areas, the frequency of each area is not affected by the frequency deviation of the other control area. In the absence of an underlying control signal such as ACE, the reserve exchange needed to maintain equilibrium cannot be initiated and co-ordinated with the same convenience as in the case of a synchronous interconnected system that appropriately responds to ACE signals. Therefore, an appropriate mechanism must be in place to optimize the exchange of balancing reserve between two areas through HVDC links. This should allow for maintaining system frequency at a nominal level, maintaining system security, and allocating power regulation among the generating units with minimal system operation costs. Addressing this challenge is the primary contribution of this thesis.

The distribution of power flows over transmission elements is governed by the laws of physics (Kirchhoff's and Ohm's laws), and is largely determined by the network topology and the physical characteristics of the lines. Therefore, in order to allocate balancing resources in each synchronous area and coordinate the flows on the transmission system, it is necessary to use load flow calculations. Power

flow models account for grid loop flows, and make it possible to understand how much power will actually flow on transmission lines for a given set of generation dispatch and load profiles [21]. The power flow model is used to compute voltage magnitudes, phase angles, and flows of real and reactive power through all branches of a synchronous network under steady-state conditions.

Optimal Power Flow (OPF) models have the added advantage of assisting TSOs in ranking alternatives according to economic and other technical criteria. OPF takes the output of power flow models and analyses them according to user defined objective functions, such as cost minimisation or minimisation of transmission loading [2, 22]. The model used in this thesis for the proposed balancing market is the so-called flow-based market model which explicitly addresses the effect of the transmission network on market transactions, thus, providing realistic solutions that can be used to effectively co-ordinate reserves. More on this is explained in Chapter 5.

## Chapter 3

# The Northern European Power Markets

This chapter provides a perspective on the northern European power markets that are the subject of the current research. It begins with the key facts of the day-ahead market in each system. The scope is then narrowed down to the balancing market in each system. As referred to in the previous chapter, balancing markets in Europe deal with the two functional aspects of procurement and employment of balancing services. Hence, the description of each individual market is dedicated to how TSOs procure and employ balancing services, taking into account the current balancing structure in each system.

Sections 3.1, 3.2, and 3.3 outline the description of the Nordic, German and Dutch power systems, respectively.

### 3.1 The Nordic System

The interconnected Nordic system is made up of four national control areas: Norway, Sweden, Denmark, and Finland, where a different TSO is responsible for the security of supply and balancing between production and consumption in each of the control areas. These TSOs are: Statnett SF<sup>1</sup> in Norway, Svenska Kraftnät (SvK)<sup>2</sup> in Sweden, Energinet.dk<sup>3</sup> in Denmark, and Fingrid<sup>4</sup> in Finland.

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<sup>1</sup>[www.statnett.no](http://www.statnett.no)

<sup>2</sup>[www.svk.se](http://www.svk.se)

<sup>3</sup>[www.energinet.dk](http://www.energinet.dk)

<sup>4</sup>[www.fingrid.fi](http://www.fingrid.fi)



Table 3.1 gives an overview on the state of power generation and consumption in the Nordic countries. Norway has almost 95% hydro power generation. Sweden and Finland have a mixture of hydro power, nuclear power and conventional thermal power generation. In both countries, hydro power stations are mainly located in the northern areas. The southern areas are, however, dominated by thermal power stations. Conventional thermal power plants and Combined Heat and Power (CHP) plants provide much of Denmark's energy needs, along with a considerable contribution from wind power production.

Table 3.1: Overview on power generation and consumption in the Nordic countries in 2008 [23]

	Denmark	Finland	Norway	Sweden	Nordic
Population (Mill)	5.5	5.3	4.8	9.3	24.9
Total consumption (TWh)	36.1	87.0	128.9	144.1	396.1
Maximum load in 2008 (GW)	6.4	13.7	21.5	24.5	66.3
Elec. generation (TWh)	34.6	74.1	142.7	146.0	397.5

Figure 3.1 represents the accumulated Nordic generation portfolio in 2009 and the share of each type of production [24, 25].

In the other renewables category in Figure 3.1, the following are included: biomass energy (5.5%), photovoltaic energy (0.1%), waste combustion power plants (1.1%), and other resources (0.3%). The percentage figures correspond to the percentage of total annual energy production [24, 25].

Western Denmark is synchronised with the central European power system, and is interconnected to the Nordic system through HVDC links. Therefore, the frequency in Western Denmark is not affected by the rest of the Nordic system's imbalances. However, Western Denmark takes part pro-actively in the Nordic frequency control by delivering and using the balancing services through HVDC links.

### 3.1.1 The Nord Pool market

In 1990, the Parliament of Norway decided to deregulate the market for power trading. In 1993, Statnett Marked AS (later becoming Nord Pool ASA and now

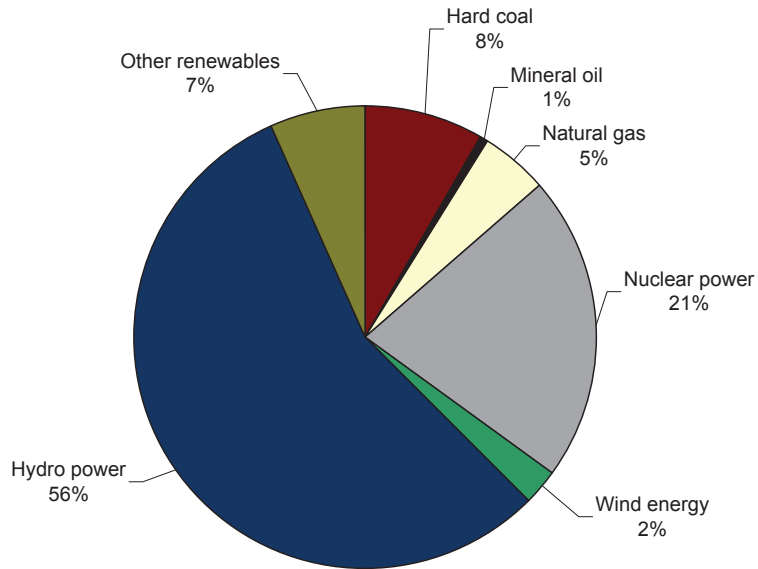


Figure 3.1: Share of annual production in the Nordic system in 2009

named Nord Pool Spot AS<sup>5</sup>) was established as an independent company. In 1995, the Norwegian parliament passed the framework for an integrated Nordic power market based on report No.11 1995/96, together with Nord Pool's licence for cross-border trading. Afterwards, the day-ahead wholesale auction trading system was extended to Sweden in 1996, Finland in 1998, Denmark in 2000, and Germany in 2005. Estonia joined the Nord Pool market in 2010.

The transition from the market phases to physical operation, and the role of the Nordic power exchange (Nord Pool) and TSOs are shown in Figure 3.2.

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<sup>5</sup>[www.nordpoolspot.com](http://www.nordpoolspot.com)

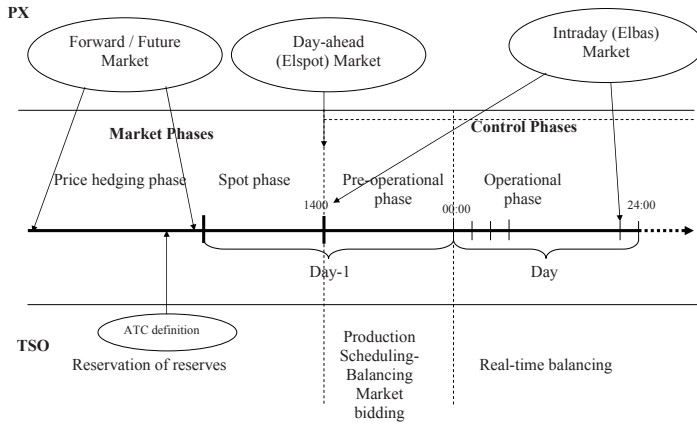


Figure 3.2: Transition from the market phases to physical operation [26]

The market phases commence with bilateral contracts and financial trading, and finish with the spot market settlement. The Available Transmission Capacity (ATC) is defined before the opening of the day-ahead market. The forward/future market is used to manage market risk, and hedge the exposure to risk in the spot markets [15]. Depending on the time horizon, the futures market may incorporate information on reservoir fillings, expectations about future events (such as the commission of a new transmission line or new capacity), or other factors that may influence the electricity price in the long-run [15, 26].

The next step is the day-ahead or the Elspot market. In the Elspot market, hourly power contracts are traded daily through the market place platform called Nord Pool Spot AS for physical delivery in the next day's 24-hour period. The price calculation is based on the balance between bids and offers from all market participants to find the intersection point between the market's supply curve and demand curve. This trading method is referred to as equilibrium point trading [15]. The price mechanism in the Elspot market adjusts the flow of power across the interconnectors and also on certain connections within the Norwegian grid to the available trading capacity given by the Nordic transmission system operators [15]. Thus, the Elspot is a common power market for the Nordic countries with an implicit capacity auction on the interconnectors between the bidding areas. Figure 3.3<sup>6</sup> shows the map of bidding areas in the Elspot market.

In 2010, 74% of the total power consumption in the Nordic system was traded

<sup>6</sup><http://www.nordpoolspot.com>



Figure 3.3: Nord Pool day-ahead market bidding areas [27]

in Nord Pool Spot AS. It operates the day-ahead market for electrical energy, the Elspot market, and the intra-day market (the Elbas market) [28].

Following the Elspot market, the control phase starts with the pre-operational step where production scheduling is determined by each producer, and the market players submit bids for the real-time balancing market. In the operational phase, the TSO activates the bids from market participants in order to balance the system with minimum cost. The operational requirement for the Nordic system is specified in a common system operation agreement [7].

The intra-day or the Elbas market functions in parallel with the pre-operational phase. The Elbas market is a continuous intra-day market, and the aim is to improve the balance of the physical contracts of the participants. The adjustments to trading in the day-ahead market are made until one hour ahead of the energy delivery. This is a way to fine-tune the market participants against their

anticipated day-ahead inaccuracies. The trading session for a specific day starts after the publication of the results of the Elspot market for that day [28, 26]. Currently, the liquidity (increased cash flow) is still limited in the Elbas market. However, with an increase of wind power production, the volume traded in the Elbas market is predicted to develop at an accelerated speed in the coming years [28].

### 3.1.2 Provision of the balancing reserves in the Nordic system

A common system of balancing reserve capacity provision is still not in place in the Nordic electricity market, and all the constituent countries have their own arrangements. Each TSO procures its share of reserves as it deems appropriate. Following is a brief introduction to the reserve procurement mechanism in each country.

In Norway, a reserve capacity market is run by Statnett to procure sufficient reserves during tight high load wintertime. This market is called RKOM (RK-opsjonsmarkedet), and the aim is to ensure sufficient balancing reserves to be available in the real-time balancing market through market-based payment for reserve availability [26, 29]. Statnett decides how much reserve is needed during a given period (mainly in the tight periods during wintertime (October to April) when the demand is quite high, and organises tenders for making option contracts with producers and large consumers to guarantee the fulfilment of this requirement. The market is cleared weekly, and the market clearing price is determined as the price of the last offer accepted [30]. A market participant with an accepted bid is obliged to make the offered volume available in the real-time balancing market, and the supplier receives a capacity payment for the availability of their reserve resources [29, 26]. In the RKOM market, Norway is divided into geographical regions NOA, NOB and NOC based on network bottlenecks and distribution of reserves. These areas are shown in Figure 3.4 [30].

In the Swedish system, SvK is responsible for the provision of a maximum 2000 MW of the so-called peak load reserve to be used in the power shortage situations [31]. The peak load reserves are procured annually through bilateral agreements, and the sellers (producers and/or consumers) receive a premium for making the reserve available on short notice during tight times especially in the wintertime [32]. In the real-time balancing market, the market participants bid at a fixed premium plus their marginal cost for either generation or consumption. The fixed premium cost should be high enough, ensuring that the peak



Figure 3.4: Geographical regions in RKOM market [30]

load reserves are the last accepted bids. The premium cost for peak load reserves are financed by the BRPs in relation to their total consumption of balancing reserves [32].

In Finland, a temporary act for peak load reserves came into effect from December 2006 to February 2011. According to [33], Fingrid will continue with the same arrangement. In the early stages, only power plants participated in the arrangement. Fingrid plans to facilitate the participation of demand response in the peak load capacity arrangement from 1 December 2013. The purpose is to maintain balance between demand and supply during the peak load in the wintertime. The implementation of this mechanism ensures that mothballed generators which are rarely used, mainly coal condensing production units, are not decommissioned, and the production capacity of these units is available for the market during the peak load period in the wintertime. The financing of the peak load power arrangements is covered by separate charges set by the TSO to the users of the Finnish power system [31]. Fingrid arranges open competitive bidding concerning the participation of power plant capacity in the annual market, and also has an hourly market for supplementary procurement once a day whenever necessary [33].

The Danish power system is split into two control areas, western Denmark (DK1) and eastern Denmark (DK2), each part of a different synchronous system, i.e., RG continental Europe and the Nordic system, respectively. The FCNOR

and FCDR reserves (see Section 2.4.2) exist only in DK2, and primary and secondary reserves exist only in DK1. Manual balancing reserve (FADR reserve) exists in both parts of Denmark. FADR reserves are considered as tertiary reserves in DK1. Energinet.dk buys the secondary reserve on a monthly basis while FADR is bought through daily auction. The FADR reserve is procured as a combined, symmetrical reserve for upward and downward regulation [34]. An auction is held once a day for each of the hours of the coming day of operation. All bids for FADR reserve have to be placed at 9.30 AM. The bids must state an hour-by-hour volume and a price for the following day of operation. If the HVDC link is fully loaded from DK2 to DK1, Energinet.dk may require manual reserves in excess of the ones purchased in DK1. In these instances, Energinet.dk will host an additional auction in the afternoon. The second auction is executed in the same way as the first auction to procure enough manual reserve in DK1 [35].

### 3.1.3 The Nordic balancing power market

After the spot market has been settled, BSPs submit bids for upward and downward regulation to their respective TSOs, who transfer the bids to the common TSO information system, called Nordic Operational Information System (NOIS), for the common balancing power market [36]. The bids are aggregated and sorted by prices, and balancing resources are chosen from this list in the increasing order of prices. The market is settled for each hour, with the most expensive activated unit setting the price for the whole of the activated capacity (marginal price). The synchronous Nordic system has one mutual balancing power market, and the cheapest bid should be chosen irrespective of nationality, provided there is no congestion problem in the grid. However, in the case of congestion, some of the regulating bids will be disregarded, and the regulating price for the congested area will become higher (in the case of upward regulation) or lower (in the case of downward regulation) than that of the other parts of the system to match the transferred power and available capacity on the interconnections [26, 27].

In general, the imbalance volume for each BRP is equal to the difference between its contracted energy volume and its real-time metered energy volume. All market participants are metered in the grid, and the difference between planned and real-time volumes is settled according to the prices and rules established in the real-time balancing power market. After introducing further harmonisation in the balancing markets in the Nordic system in 2009, two separate types of imbalance with the following definitions have been introduced for each type of BRPs (Before 2009, the two price system was in use in the Swedish and the Finnish systems). The real-time imbalance pricing for each category is handled differently.

- Production imbalance = *metered production - planned production*
- Consumption imbalance = *planned production + metered consumption + actual trade*

For the consumption imbalance, one-price settlement is applied, whereas a two-price settlement is applied for the production imbalance. In the two-price settlement, regulation price is applied for imbalances in the “wrong” direction, while spot price is applied for imbalances helping the system. In the one-price settlement, the same price (regulating price) regardless of the direction of the individual imbalances with respect to the system imbalances is applied. This system was intended to encourage producers to submit more accurate production plans [37]. More details on this can be found in [38].

## 3.2 The German System

The German system is a part of the continental European synchronous system<sup>7</sup>. Germany is the largest system in the northern European area with 82.1 million inhabitants and an annual electricity production of 620 TWh representing 22.4% of the total production in RG Continental Europe in 2009 [24, 25]. Thermal power production dominates in the German system, whereas a substantial share is provided by lignite coal and nuclear power plants. The other type of production includes a mix of natural gas, hard coal and hydro. Electricity generated by renewable sources, especially wind, is increasing significantly. Figure 3.5 shows the accumulated installed wind power capacity from 2000 to 2010 [39], demonstrating the continuously increasing trend towards integrating wind power production.

Figure 3.6 represents an overview of the German production portfolio in 2009 and the share of each type of production [24]. In the other renewables category in Figure 3.6, the following are included: biomass energy (5%), photovoltaic energy (2%), waste combustion power plants (1%), and other resources (2%). The percentage figures correspond to the percentage of total annual energy production [24, 25].

### 3.2.1 The German market

The first German power exchange, the Leipzig Power Exchange (LPX), started operations in June 2000. In August of the same year, a second power exchange,

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<sup>7</sup>In July 2009, ETSO’s succeeding organisation ENTSO-E was founded with NORDEL and UCTE (Union for the Co-ordination of Transmission of Electricity) as the regional Nordic and RG Continental Europe subgroups, respectively.



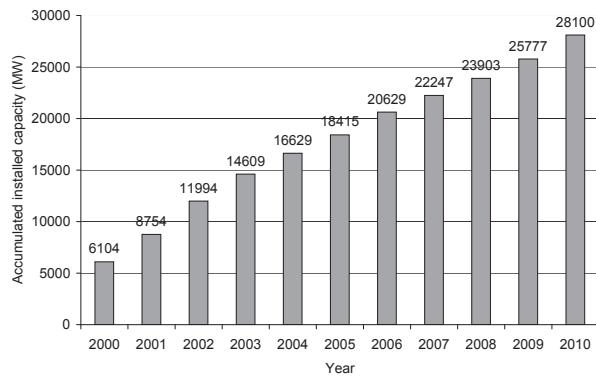


Figure 3.5: Cumulative installed wind power capacity in Germany [39]

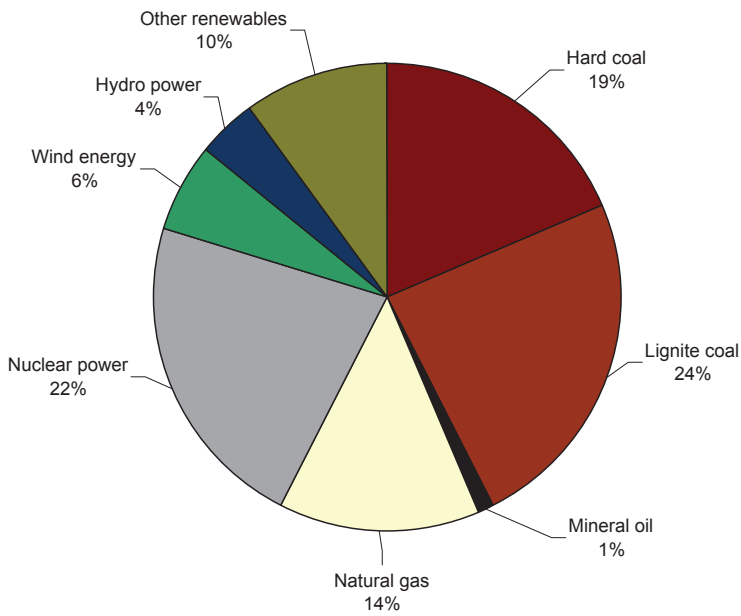


Figure 3.6: Share of annual production in the German system in 2009

the European Energy Exchange (EEX) in Frankfurt, began operations. On 1 January 2002, merging of the two German power exchanges, i.e., LPX and EEX,

resulted in the formation of the European Energy Exchange (EEX)<sup>8</sup> in Leipzig. This new exchange has set itself the goal of becoming Europe's leading power exchange. In September 2009, EEX and the French exchange Powernext established the integration of the power spot markets under the umbrella of the new spot trading company named EPEX Spot - European Power Exchange. EPEX Spot is based in Paris, and owned equally by Powernext and EEX. It facilitates the hourly balancing of physical power delivered the following day in the French, German/Austrian and Swiss hubs [40]. The traded power volume in the German EEX was 36% of the gross inland electricity consumption of Germany in 2010 [41]. The transition from the market phases to physical operation is similar to what is depicted in Figure 3.2, starting with the forward market, continuing with the day-ahead and the intra-day market, and ending with the real-time balancing market [20]. The standard products traded in the day-ahead market are the hourly day-ahead contracts. The hourly prices of the contracts are published in the so-called Phelix index at the EEX Website.

### 3.2.2 Provision of the balancing reserves in the German system

Before the integration of balancing markets in 2008, the electricity system in Germany was operated in four control areas by four TSOs shown in Figure 3.7. All these TSOs still have the responsibility for system balancing under the co-operation framework in the common nationwide balancing market [42]. The stepwise integration has been implemented in four modules described in Section 4.2.4. The TSOs are: EnBW Transportnetze AG, Amprion GmbH (formerly RWE Transportnetz Strom GmbH), TenneT TSO GmbH (formerly Transpower Stromübertragungs GmbH) and 50Hertz Transmission GmbH (formerly Vattenfall Europe Transmission GmbH). Figure 3.7 shows four German control areas. Within the scope of Verband Deutscher Netzbetreiber (VDN), the German TSOs have adopted Transmission Code 2007, which includes the rules and regulations, as well as the technical requirements for the procurement and employment (activation) of balancing reserves [43].

Primary and Secondary reserves have been tendered weekly since June 2011. The primary and the secondary reserve procurement is implemented nationwide. The contract includes both a capacity payment for reserve availability, and the energy payment that is paid to the bidder, if the generation unit is effectively called on in the real-time balancing. The tertiary reserve in day-ahead auctions is allocated in four hour increments. The auctions for tertiary reserve, called minutes reserve, are held each working day. Auctions for weekends, Mondays

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<sup>8</sup>[www.eex.com](http://www.eex.com)

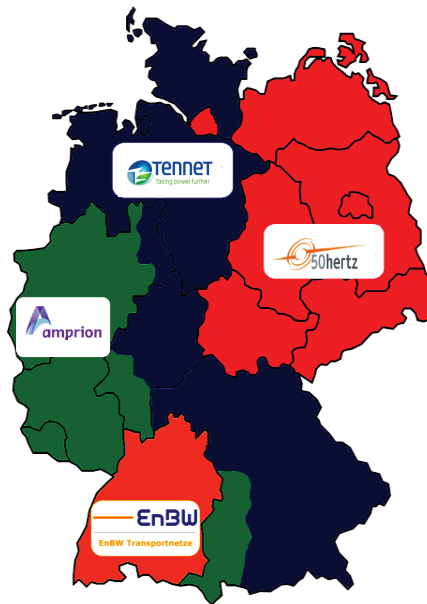


Figure 3.7: The four German control areas. Source: VDN

and holidays are held on the last preceding working day [20].

All bidders must pass a pre-qualification procedure based upon the rules of ENTSO-E [4], as well as the common rules of the German grid [20]. Once qualified, they will bid in an appropriate market. The TSOs jointly initiated an internet-based marketplace,<sup>9</sup> where potential bidders can bid separately for each type of reserve. The submitted bids are sorted from the lowest to the highest capacity price (EUR/MW) to yield a merit order list. The favourable bidders are chosen according to the merit order list, and the procured balancing reserve is used in the subsequent week when needed. The selected providers receive their own bid prices instead of the price of the last (marginally) selected bid.

### 3.2.3 Balancing energy in the German system

All four German TSOs use a single-price balancing energy settlement scheme, which is the average price of the activated bids for secondary reserve and minutes reserve. The German balancing energy market is cleared four times an hour,

<sup>9</sup><https://www.regelleistung.net/regelleistungWeb/?language=en>

which means that there are 96 Program Time Units (PTUs) per day [26, 44]. Imbalance prices are computed for each balancing interval. The imbalance price for each balancing interval is determined by adding up the TSO's net energy expenditure (payable to or receivable from the providers of secondary control reserve and minutes reserve that has been activated during the quarter-hour), and dividing this by the aggregate imbalance. The regulation states, e.g., upward/downward regulation, are not defined separately, and the imbalance price is symmetric (a BRP with a positive imbalance, i.e., which has fed more energy into the grid than scheduled, receives the same price as that paid by BRPs with a negative imbalance, and vice-versa). In special circumstances with negative energy prices, a BRP with a positive imbalance may have to pay the TSO. Capacity availability fees for secondary control reserves and minutes reserve are not passed on to BRPs, but are instead factored into the grid using tariffs [44].

### 3.3 The Dutch System

The Netherlands is a part of the continental European synchronous system. It has a population of 16.7 million with an annual electricity production of about 113 TWh in 2009. The power production is based on a mix of hard coal, natural gas-fired and oil-fired power plants, with a substantial share of CHP plants. The make-up of the generation types in the Netherlands in 2009 is depicted in Figure 3.8 [24, 25].

In the other renewables category in Figure 3.8, the following are included: biomass energy (3.17%), photovoltaic energy (0.04%), waste combustion power plants (2.7%), and other resources (0.09%). The percentage figures correspond to the percentage of total annual energy production [24, 25].

#### 3.3.1 The Dutch market

Established in May 1999, the APX Power NL operates a day-ahead spot market in the Netherlands. The day-ahead market is a voluntary market, and trading takes place the day preceding delivery. Trading in the day-ahead market allows APX Power NL members to achieve a balance of their purchase and sale portfolios on an hour-by-hour basis. APX Power NL is owned by APX ENDEX, founded by merging APX and the Amsterdam-based European Energy Derivatives Exchange (ENDEX). ENDEX, established in 2002, was a marketplace for future and bilateral contracts. In September 2008, the APX Group agreed with ENDEX to purchase 91% of its shares to merge both companies. Thus, synergies

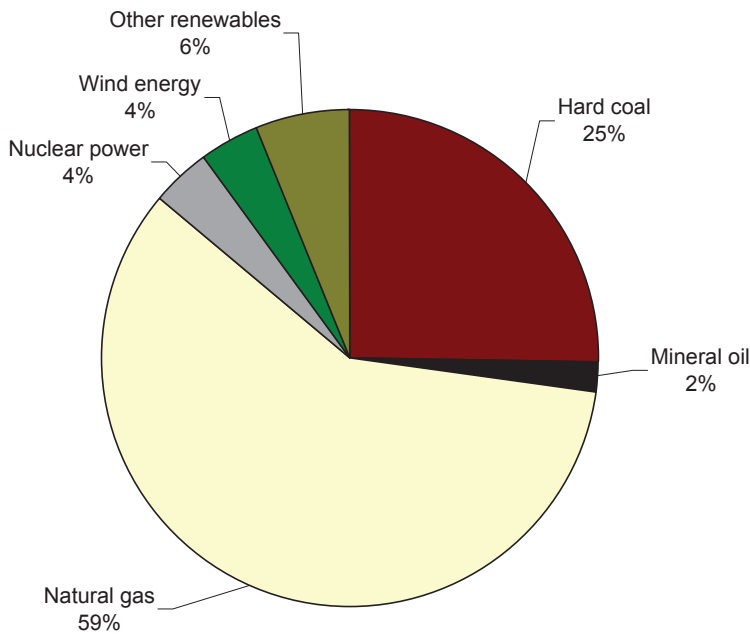


Figure 3.8: The Dutch production share by generation type in 2009

from the combination of APX's experience in spot trading and ENDEX's experience in derivatives trading can offer a strengthened position in the integration process [45]. After merging the APX Group and ENDEX, a new name APX-ENDEX was introduced [45].

The volume traded in the APX Power NL day-ahead spot market has grown steadily from its inception. The yearly total day-ahead volume traded reached 26% of annual electricity consumption in 2009 [46, 47]. The different phases of the electricity market in the Netherlands are similar to those shown in Figure 3.2, beginning with the forward market, continuing with the day-ahead and the intraday market, and ending with the real-time balancing market [26].

The Dutch TSO, TenneT TSO B.V., is responsible for maintaining the instantaneous balance of supply and demand in the Dutch electricity network, and for resolving constraints which may occur on the transmission network. In order to carry out this function, TenneT operates a market for balancing reserves in the Netherlands (primary, secondary and tertiary reserves, in the order mentioned,

according to ENTSO-E recommendation [4]).

### 3.3.2 Provision of the balancing reserves in the Dutch system

Secondary and tertiary reserves for balancing are procured in the same market but defined as different products in the Netherlands. The products are differentiated according to activation time and activation duration [17]. All connected parties with total capacity exceeding 60 MW are obliged to offer all available reserve capacity to the balancing market without capacity payment. Other connected parties with a capacity less than 60 MW are allowed to bid in the balancing market, but are not obliged to do so [17, 48]. As in the case of the German balancing market, the Dutch balancing market is cleared each quarter, so that PTU is fifteen minutes. All bids must be received one day before the day of delivery. Bids for balancing are prepared for each PTU. A bid must include the size of upward and/or downward capacity, the price, the location in the grid and the activation time. On the basis of the bids, TenneT creates the “bid-ladder” for each PTU of operation, and activates the required reserve according to the bid-ladder [26]. To obtain the desired regulation speed (MW/min), TenneT may activate several regulation bids simultaneously. The selected providers receive the imbalance prices on the marginal prices of upward and downward regulation bids selected in the balancing energy market [48].

TenneT also calls upon a 300 MW emergency capacity in order to restore the system balance if no (sufficient) regulating and reserve capacity is available. Emergency capacity always has a positive value (capacity supplied to TenneT). TenneT obtains emergency capacity on a yearly basis from a number of suppliers on a contractual basis via tenders. For these tenders, an announcement will be made available on the TenneT website via the news items. This emergency power is taken out of the day-ahead market as well as the balancing market bids [49].

### 3.3.3 Balancing energy in the Dutch system

Each BRP has to submit its plan for exchange with neighbouring countries (IET-planning) to TenneT, the TSO, a day in advance. TenneT may approve the plan if the grid is found to be operationally (N-1) secure, or return the plan to the BRP with a request for modification. After the day-ahead market gate closure, the BRPs must submit Energy Programmes (E-Programmes) and Transport Prognoses (T-Prognoses) for each PTU, including all the results of IET-planning to

TenneT. In an E-Programme, BRPs specify the planned net volume that is intended to be injected into the grid or withdrawn from it. The final versions of E-Programmes must be submitted to TenneT at least one hour before the PTU of operation. In a T-Prognosis, the absolute transport volumes and relevant grid supply points are specified. The goal of T-program is to make it possible for the grid owner and the TSO to verify the feasibility of the resulting load flow with respect to the operation criteria of the grid [48, 50].

According to [51], the regulation state for a PTU is 0 if neither upward nor downward regulation is requested, +1 if only upward regulation is requested, and -1 if only downward regulation is requested. If both upward and downward regulation are requested within a PTU, depending on “balance-delta” representing the continuous minute-by-minute actual regulating volume, the regulation state is either -1, +1, or +2. Under these conditions, the regulation state is +1 if balance-delta forms a continuous non-decreasing record, -1 if balance-delta forms a continuous non-increasing record, and +2 if balance-delta forms neither a continuous non-decreasing record nor a continuous non-increasing record [51].

The balancing prices for the regulation states +1 and -1 are equal to the highest and lowest bids for activated balancing reserve, respectively. Dual pricing is used in imbalance settlement when the regulating state is +2, where the balance price for upward regulation is equal to the highest activated bid, and for downward regulation is equal to the lowest activated bid [51]. The Dutch balancing market contains an “incentive component”. It is an added financial component to compensate the “system performance” reduction. The system performance is based on two criteria related to the weekly average and actual number of inadvertent exchanges with other countries. The system performance is monitored weekly. If the performance criteria is not met, the incentive component can be increased, leading to higher incentives for the BRPs to be in balance [52].

An overview of balancing markets in each country within the northern European power system is presented in Table 3.2.

Table 3.2: Overview of balancing markets in the northern European power system

	Norway	Sweden	Finland	Denmark	Germany	the Netherlands
<b>Reserve Procurement</b>						
Frequency of reserve procurement	Weekly (Oct. to Apr.)	Yearly (Peak load)	Yearly Daily	Monthly Daily	Weekly Daily	Yearly Daily
Mechanism	VPL <sup>1</sup>	BC <sup>2</sup>	BC	BC / VPL	VPL	BC / MPL <sup>3</sup>
Payment mechanism	MP <sup>4</sup>	MP	MP	MP	Pay as bid	MP
GCT <sup>5</sup> for first energy program	19:00 D-1	16:00 D-1	16:30 D-1	15:00 D-1	14:30 D-1	13:00 D-1
GCT for final energy program	45 min before physical delivery					
<b>Imbalance Settlement</b>						
PTU	60 min					
Imbalance pricing	Marginal price					
Single/dual pricing	Single					
One-/two-price settlement	Two (producers) & One (consumers)					

<sup>1</sup>Voluntary Pool

<sup>2</sup>Bilateral Contracts

<sup>3</sup>Mandatory Pool

<sup>4</sup>Marginal Price

<sup>5</sup>Gate Closure Time



# Chapter 4

## Cross-border Balancing

As stated in Chapter 1, this thesis aims to contribute to the design of a scientific foundation that would create a framework for efficient, market-based balancing of a power system that can be implemented in multinational power markets.

The thesis is aimed at developing the requisite knowledge on the technical aspects of multinational balancing markets for the northern European area. More specifically, the research is targeted towards developing a fundamental framework for evaluating the distribution of balancing resources in each control area. Recall that distribution of balancing resources means the optimal allocation of reserve capacity. This capacity is supposed to be procured from the existing multinational balancing markets within the Nordic system, and/or the advocated multinational balancing markets outside of the Nordic system.

Mathematical models for the integrated balancing of the northern European balancing markets are subsequently put forward (in Chapter 5). In this context, it is illustrative to describe the present status in the existing balancing markets overview. Hence, this chapter is dedicated to the analysis of the current state of market mechanisms in place, and possible qualitative models for implementing cross-border balancing. Subsequently, a literature review on northern European balancing markets is presented.

The Council of the European Union issued an internal electricity market Directive in 1996 (96/92/EC) that set goals for a gradual opening of the electricity market for all member states. It made significant contributions towards the creation of an internal market for electricity. Experience in implementing this directive showed the benefits that may result from the internal market in electricity,

in terms of efficiency gains, price reductions, higher standards of service and increased competitiveness [53]. A Directive in 2003 (54/EC) gave common rules for the internal electricity markets, and regulation 1228/2003 regulates access to the interconnecting network for cross-border exchanges and spells out the principle of cross-border congestion management [54]. Also, a new Directive 2009 (72/EC) of the European Parliament concerns conditions for access to the network for cross-border exchanges in electricity, and expanding the scope of Regulation (EC) No 1228/2003 [55].

Since the development of one single electricity market in Europe could only be achieved in the long term, the first step towards this aim is to establish regional markets. The regional markets in Europe are leading the way to future electricity market integration on this continent. The benefits will include improved transparency of information and better cross-border congestion management (contingent upon co-operation among TSOs on the calculation and allocation of cross-border capacity). Consequently, TSOs will be motivated to increase efforts towards balancing market integration and exchange balancing services over borders in a similar manner as is done for energy exchange in integrated day-ahead dispatch.

First, this chapter introduces alternative proposals to implement the cross-border balancing management. Next, The practical experiences of the existing balancing market integration in the continental European system are presented. Finally, it outlines a literature survey on balancing market integration in the northern European system.

## 4.1 Cross-border Trading Model and Concepts

In [56], the European Regulators' Group for Electricity and Gas (ERGEG) has stressed the fact that balancing market integration is a necessary step towards having one effective single market across the whole of continental Europe. An integration of balancing markets can facilitate the mutual procurement and/or employment of regulating resources, and is a way of using the existing cross-border capacity more efficiently by enabling those capacities available to the balancing market players for the exchange of balancing services. The integration of regulating markets prevents the balancing energy services in different control areas from being activated in opposite directions, and hence will have a significant effect on the regulating volumes in the individual markets, thereby influencing the balancing prices. ERGEG anticipates the following benefits for the integrated balancing markets [56]:

- Providing more diversified balancing resources and further opportunity to balance the deficit and surplus of net generation, thus helping TSOs to lower balancing costs and increase market efficiency.
- Increasing the security of supply, by contributing to the sharing of reserves which allows TSOs to call upon balancing services from neighbouring TSOs through market mechanisms in place.
- Increasing competition in the market and reducing the possibilities for the exercise of market power.

As has been discussed, there is no organisation of balancing markets in the northern European countries. For example, in the Nordic system, there is a common agreement only on balancing settlement, whereas common reserve procurement is not in place so far. Therefore, the implementation of balancing market integration may entail different levels of national balancing markets' harmonisation. According to [26, 57], the way to a fully integrated national balancing market would be to go through steps of increasing levels of harmonisation. An incremental integration of the market is more practical than transitioning directly from the current national market to a multinational structure. It provides system operators with an option to wait and observe the effects of each integration step, avoiding the immediate high transition costs and lock-in effects of a larger transition. Different proposals for balancing market integration have been put forward by the European organisations, i.e., European Transmission System Operators (ETSO)<sup>1</sup> [58, 59, 60], ERGEG [56], and Eurelectric [61], for enabling cross-border exchange of balancing services. All these proposals are based on the two main conceptual models developed by ETSO [58], which are as follows:

- A TSO trading directly with a BSP in another TSO's area (BSP-TSO)
- A TSO trading with one or more TSOs (TSO-TSO)

The principle of each model is as follows:

1. A "BSP-TSO" trading model has two or more TSOs working towards establishing a compatible balancing market, which allows the BSPs to choose the balancing market they want to bid (local or neighbouring market) into, and enter into a contract directly with the TSO of the neighbouring area. However, the notification of the change in generation/consumption schedule will have to be ensured by the BSPs. Figure 4.1 shows this arrangement.

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<sup>1</sup>On 01 July 2009 ETSO was phased out and all operational tasks were transferred to ENTSO-E

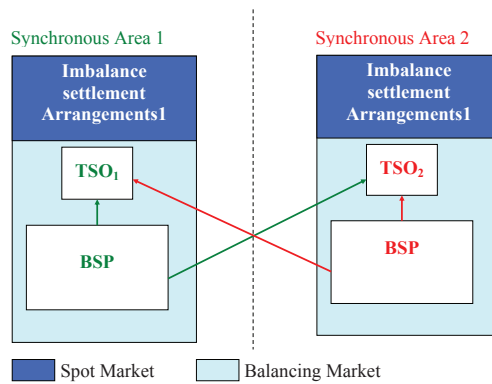


Figure 4.1: Contractual arrangement of BSP-TSO trading model [58]

2. A “TSO-TSO” (or multiple TSOs) trading model is exclusively meant for the exchange of balancing services between TSOs, where the TSOs themselves exchange balancing services in an efficient manner. The BSPs can only submit bids to the TSO to which they are directly related. Unlike in the BSP-TSO arrangement, BSPs cannot choose TSOs themselves, and it is the the TSOs’ responsibility to acquire cross-border capacity. This arrangement is described in Figure 4.2.

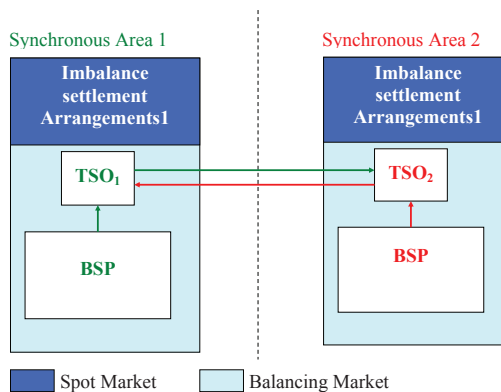


Figure 4.2: Contractual arrangement of TSO-TSO trading model [58]

The experiences from both day-ahead market coupling, and moving from separated markets to a common market are relevant in the context of balancing market integration. In the day-ahead market, two important methods are implemented to allocate the cross-border energy exchange between two national day-ahead markets: the *explicit auction* and *implicit auction* methods [15]. As mentioned in [19], the crucial insights gained are applicable to the cross-border balancing trade as well. The explicit auction and implicit auction methods are explained briefly as follows:

- In the **explicit auction**, two commodities, transmission capacity on cross-border interconnections and electrical energy, are traded in two different independent auctions. The transmission capacity is normally auctioned through long-term contracts, i.e., annual, monthly and daily auctions based on the average prices in each national electricity market. Under this arrangement, market parties themselves decide on the amount of energy to be bought/sold in each national market. The explicit auction is considered a simple method of handling the capacity on the international interconnections in Europe, and the commodities each have different auctions [62]. Therefore, there is a lack of information about the prices of the other commodities, and this can result in an inefficient utilization of interconnections, loss of social welfare, and more frequent adverse flows [63, 64, 65].
- In the **implicit auction**, the day-ahead transmission capacity is used to integrate the spot markets in the different bidding areas in order to maximize the overall social welfare in two or several markets. The flow on an interconnection is found based on market data from the marketplace(s) in the integrated markets. Thus, the auctioning of transmission capacity is included (implicitly) in the auctions of electrical energy in the market. Implicit auctions aim to eliminate the weakness of potential cross-border inefficiency in explicit auctions by internalizing the arbitrage into the centralised auction procedure of the power exchange organising the day-ahead market nationally. Implicit auctions ensure that electrical energy flows from the surplus areas (low price areas) towards the deficit areas (high price areas), thus also leading to price convergence [62].

Vandezande [19] has presented an extensive literature review of the traditional debate of explicit versus implicit auctioning. Most of the reviewed papers have confirmed that implicit auctioning led to a welfare-maximizing outcome and also market power reduction. On the other hand, the European experience presents the evidence of the inadequacy of the explicit auction as pointed out in [66, 67, 68, 69]. Kristiansen [66, 67] analyses auction prices for the cross-border auctions between West Denmark and Germany, and between East Denmark and Germany (the Kontek cable). He finds that capacity auctions do not reflect the

value of the underlying asset as specified by the appropriate valuation of the energy price differentials between West Denmark and Germany, and East Denmark and Germany. As such, the explicit auction procedure is not cost efficient. Ehrenmann and Neuhoff [68] show that the integrated market design (an implicit auction) performs better than a coordinated explicit auction. Meeus [69] states that cross-border trade in an explicit auction is often in the direction of the average price difference, even if the hourly price spread is frequently in the other direction.

This insight from the implicit auction and the explicit auction is applicable in proposals for the cross-border balancing services exchange. The TSO-BSP model is similar to the explicit auction, where BSPs themselves identify the best possible allocation of their services either to their national market or to the international market based on the available cross-border capacity. The TSO-TSO model is similar to the implicit auction, where the arbitrage opportunity between national balancing markets is identified and exploited internally between TSOs. Thus, the same comparison between the explicit and implicit auction can be extended to the TSO-BSP and the TSO-TSO model comparisons. It means that the TSO-TSO model exploits the cost reduction potential more efficiently, and thus could be a very good candidate to implement cross-border trading. ERGEG [56] confirms the same argument and proposes the TSO-TSO model as the most suited one for cross-border balancing. According to [56], under the TSO-BSP model, BSPs are supposed to comply with different balancing markets and IT systems to exchange balancing services across borders. But since BSPs do not have access to complete system information such as available cross-border capacities and their own standing in the merit order list (intra and inter area-wise), TSO-BSP model is suboptimal. Each individual BSP has to make decisions such as whether to offer his services to the local TSO or to the neighbouring TSO based upon limited system information available, while TSOs in the TSO-TSO model have access to more information on system state or their disposal. On the other hand, handling the scheduling changes is more convenient in case of the TSO-TSO trading within the short balancing time frame [70].

In the day-ahead market integration, different levels of harmonisation have been introduced in an implicit auction. They include “volume coupling” and “price coupling” arrangements. The main purpose of volume coupling is to optimally exchange energy among coupled markets, while each individual market can still keep its own rules. Implementing this arrangement accelerates the mechanism of market coupling [62]. The coupling system uses a single algorithm to determine the flows across the interconnectors between the underlying regions/markets, based on bid/offer information from each market. The coupling algorithm partly repli-

cates the matching rules of each coupled market. However, the day-ahead price in each market is still determined separately by the local power exchange which uses the generated cross-border volumes to locally determine their bidding area prices and volumes. Depending on the degree of replication of local market rules, there are two different arrangements called “loose volume coupling” and “tight volume coupling”. Price coupling arrangement is the result of fully integrated day-ahead markets where the coupling algorithm jointly establishes prices, generation volumes and interconnector flows for each coupled market, and takes into account all bids/offers from all markets [62].

Similar to the arrangements in the day-ahead market, and depending on the degree of balancing markets harmonisation, the TSO-TSO arrangement can be implemented under one of the following arrangements [56, 71]:

- *TSO-TSO without common merit order list* where TSOs exchange part of the available resources in their own areas. Therefore, a TSO needs to be confident that there are enough available balancing services in its control area before exchanging bids and offers with other TSOs.
- *TSO-TSO with common merit order list* where TSOs activate the cheapest available resources from a system-wide common merit order list. Moreover, the imbalances can be levelled out as far as possible by the effect of *imbalance netting*. In this way, a shortage in one area can partially or fully be supplied by a surplus from neighbouring areas without the need for activating balancing energy. This effect will result in less activated balancing energy in real-time dispatch. The TSO-TSO with common merit order list can be implemented under the supervision of a “super TSO”, where BSPs submit balancing bids to their “local TSO”, who then sends the balancing bids to the super TSO. The super TSO selects balancing bids from the “bid ladder” (joint list) for the system balancing, after evaluating their effects on the interconnections (which are duly checked and controlled against overloads). The super TSO communicates the requirement for energy to the TSO to which the resource is connected. The local TSO then contacts the resource in question and requests the incremental generation. Thus, local TSOs act as intermediaries between local BSPs and the super TSO [56]. Figure 4.3 schematically describes this balancing arrangement.

Full harmonisation is not a prerequisite under the TSO-BSP and the TSO-TSO (without common merit order list) arrangements. However, they pave the way to faster implementation of cross-border balancing [56]. Eurelectric proposes a road map for the integration of balancing markets in continental Europe, as

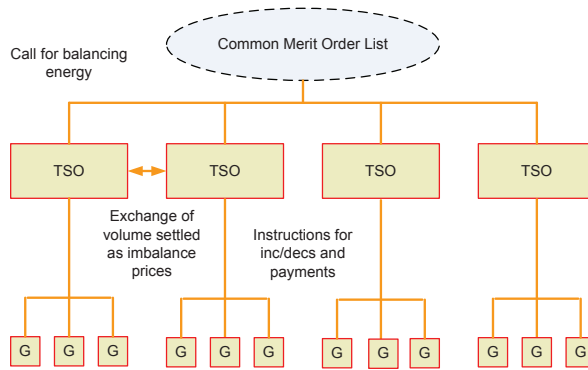


Figure 4.3: Contractual arrangement of TSO-TSO trading model with common merit order list [71]

shown in Figure 4.4 [61]. It starts with an interim short-term solution as the extension of a national balancing mechanism with the TSO-BSP model. The model will be extended to the long-term solution with a high degree of harmonisation with the TSO-TSO model with common merit order list.

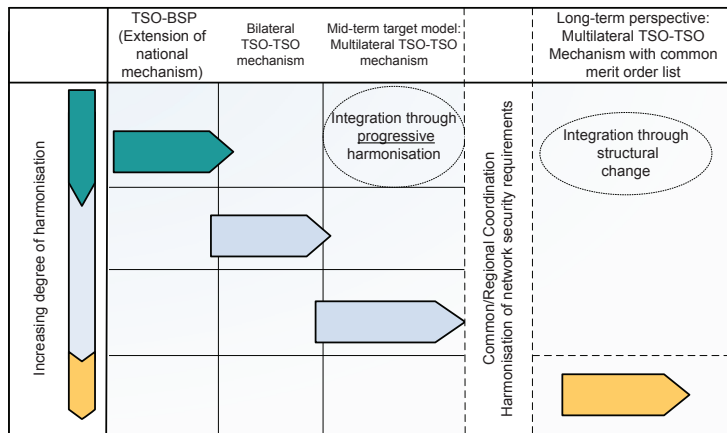


Figure 4.4: Proposed roadmap for the cross-border integration of the electricity balancing market [61]



### 4.1.1 Cross-border reserve procurement

It is important to mention that there is a fundamental difference between cross-border reserve capacity exchange and balancing energy exchange. The distinction is that the cross-border reserve capacity exchange requires certainty on the availability of cross-border capacity for the entire contract period. Therefore, the cross-border capacity should be reserved for reserve capacity exchange in day-ahead and intra-day auctions; otherwise the allocated capacity will be locked behind cross-border interconnections in the real-time balancing energy activation [72].

In this connection, ETSO introduced technical models of cross-border reserve procurement in [59]. These models are based on the level of technical integration, and the cross-border exchange of balancing services between control areas. The models are briefly described as follows:

- Technical model 1, No trading: TSOs procure their own reserve without reserve trading and exchange possibilities, but they can mutually assist each other in case of emergency.
- Technical model 2, Cross-border reserve pooling: In this model, the TSOs buy all available reserves in their own area according to their own reserve requirements. They have an exclusive right to use their own procured reserves. Moreover, they establish a common spot market for reserve energy, where they can share procured reserves with each other on a voluntary basis.
- Technical model 3, Cross-border reserve trading: In this model, TSOs can procure part of their own reserves from other control areas. Two variants of this model exist.
  1. Variant 1: In this model, TSOs have an exclusive right to procure reserve from neighbouring control areas, and the exchange capacity is reserved according to the procured amount of reserve guaranteed to avoid overload of the grid in case of activation.
  2. Variant 2: In this model, the reserve from neighbouring control areas is activated, provided transmission capacity between areas is available.
- Technical model 4, Sharing of reserve capacity: The model is similar to the cross-border reserve pooling model. The important difference is that TSOs do not have exclusive rights to use their own share of common reserve. The reserve is activated according to common merit order as far as it is possible keeping in view the grid constraints.

It is concluded that technical modes 2 and 4 lead to balancing mechanism integration and the required production harmonisation. Technical models 2 and 3 reduce long-term reserve margins. Technical model 4 enables the full integration of the balancing mechanism. In [60], ETSO describes the prerequisites for implementing these technical models by introducing integration steps from area controlling to regional controlling. These steps include the following, which are elaborated more in the next section:

- Pooling of reserves
- Sharing of reserves
- From area control to regional control

### 4.1.2 Regional balancing versus area balancing

Based on the description in [60], two levels of balance management were introduced in the cross-border balancing - *area balancing* and *regional balancing*. Area balancing is limited to a geographical area, whose production-consumption balance is taken care of by a TSO. A balancing region can consist of several balancing areas. In general, the regional balancing market is similar to the TSO-TSO trading model with common merit order list with a super TSO. In Figure 4.5, the regional balancing functions and the interaction of regional balancing and area balancing together with BSPs are shown. First, the main role of regional balancing is to request activation of the reserve from all balancing areas, and activate the optimum resources made available by the balancing areas from the merit order list. This task should support compliance with frequency and exchange deviation limits based upon common agreed standards. Next, the tie-line exchange with other balancing regions is kept to the scheduled values according to agreed standards. Further, network congestions due to balancing energy exchange across the borders between balancing areas is managed. As discussed in [60], two steps of integration should be accomplished before moving from area control to regional control - *pooling of reserve* and *sharing of reserve*. Pooling of the reserve involves the mutual activation of balancing reserves. The excessive reserve remains available for activation by the originating TSO, which can also be activated by the other TSO, provided sufficient transmission capacity is available between TSOs. Pooling of reserve requires no harmonisation, but requires an agreement between the TSOs, which include for instance pricing and inter-TSO imbalance settlement arrangement. On the other hand, sharing of the reserve involves the sharing of common reserves. This includes the determination of a required reserve volume on a regional basis, and the mandatory supply of an agreed individual share to the common reserve by each of the involved TSOs. The mandatory share of a TSO can be procured from its own area or purchased from neighbouring areas

within the balancing region. The regional balancing is taken into account in the modelling of fully integrated balancing markets within this thesis.

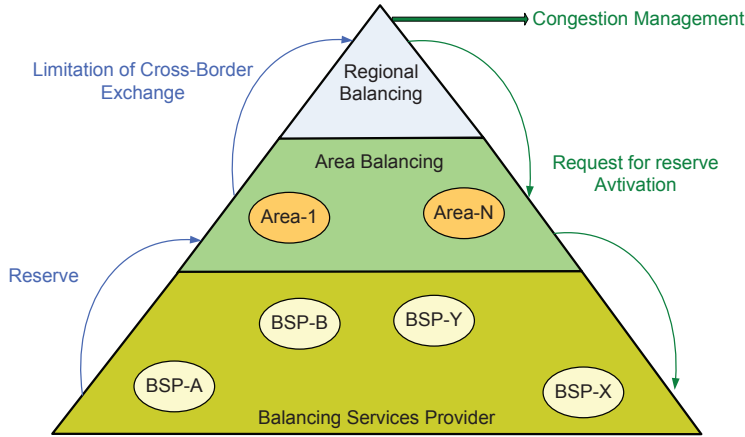


Figure 4.5: Operation of the balancing regional and area process [60]

## 4.2 Balancing Market Integration within Continental Europe

In this section, experiences from the practical implementation of market coupling in the continental European systems are presented. Different arrangements for cross-border balancing are considered, ranging from the TSO-BSP conceptual model (being implemented in Central Western European Market Coupling (CWE) between France and Germany [73]) to the TSO-TSO model without common merit order list (being implemented between France and England & Wales [74]). Also, the TSO-TSO model with common merit order list implemented in the Nordic system is described [75]. Further, the step-wise balancing market integration in Germany, and the German TSO solution to implement the so-called Grid Control Cooperation (GCC), including the cooperation between the present TSOs, is presented [42].

### 4.2.1 CWE market coupling

Trilateral Market Coupling (TLC) was established in 2006 when the markets of the Netherlands, Belgium and France were connected. Further integration took

place when a Memorandum of Understanding (MoU) among the governments, regulators, power exchanges, TSOs, and the electricity associations of Belgium, Luxembourg, the Netherlands, Germany and France was signed in Luxembourg in June 2007. The MoU agreed on the implementation of market coupling between the involved electricity markets.

At the end of 2010, the Central Western European Market Coupling (CWE) was launched, replacing the Trilateral Market Coupling. The CWE region is also linked to the EMCC coupling of Germany and Denmark through an Interim Tight Volume Coupling (ITVC) solution. This means that this market has remained in the form of tight volume coupling since the beginning of the CWE market coupling. This step was necessary to prevent deterioration in the quality of coupling between Germany and Denmark after the start of the CWE. As the word “interim” implies, this is a provisional solution that will be replaced by an enduring price coupling solution covering at least the entire CWE and Nordic regions. The connection of NorNed to the CWE Market Coupling was introduced on 12 January 2011, linking the Norwegian day-ahead market to the wider Central West European power market [76, 73].

Currently, within the CWE region, cross-border balancing exchanges are only possible between France and Germany; provided there is available cross-border capacity, German market players can participate in the French balancing mechanism. The model of cross-border trading is the “TSO-BSP” trading for the exchange of tertiary reserves.

## **4.2.2 Reserve exchange between the UK and France through the Anglo-French interconnection**

The Anglo-French (IFA) HVDC interconnection operates under the English Channel between the French and British electricity grids. It is owned jointly by National Grid Company (NGC) and Réseau de Transport d’Electricité (RTE), the TSOs in England & Wales, and France. The technical capacity of the cable is 2000 MW [74].

RTE and National Grid have been working together since 2007 to develop and implement a common tool called “Balancing Inter-TSO (BALIT)” to exchange cross-border balancing services across the IFA interconnection. The BALIT solution was implemented in December 2010, and allows each TSO to buy or sell manual balancing reserve at prices submitted by the other TSO. The implemented model for cross-border balancing is the TSO-TSO model without common merit

order list to exchange the manually activated reserves. The BALIT solution enables RTE and National Grid to exchange offers for one hour balancing products, up to one hour before delivery. A similar cross-border balancing arrangement is in place across the Moyle interconnection between Scotland and Ireland. The exchange is done based on the available capacity remaining from day-ahead market exchange. Each TSO keeps his own procurement mechanism, and shortly before real-time delivery, if a TSO has available balancing energy (surpluses), he bids it into the other TSO’s mechanism. There are 24 gate closures per day (1 per hour), and each TSO submits bids at  $H + 10 \text{ min}$  for delivery at  $[H+1\text{h}; H+2\text{h}]$ . The activation time is between  $H + 10 \text{ min}$  and  $H+30 \text{ min}$  [77]. Figure 4.6 shows the sequence of the BALIT solution. The accepted bids are published on the “system warnings and other messages” page of the Balancing Services Reporting Service (BSRC) Web site<sup>2</sup> [74].

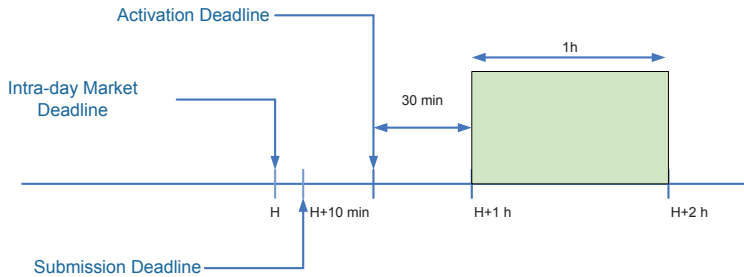


Figure 4.6: Sequence of the BALIT solution [77]

### 4.2.3 Nordpool

Besides the day-ahead integration in the Nord Pool market, the balancing market is integrated in the Nordic system. The Nordic balancing market does not distinguish between “national” and “international” balancing energy provisions. All balancing bids are gathered and sorted in a common merit-order list (or “bid ladder”). The model for cross-border balancing in the Nordic system follows the “TSO-TSO” trading model. The participants submit balancing bids to their local TSO, whereupon the local TSO sends the balancing bids to the “super TSO” (which consists of the Norwegian TSO (Statnett) and the Swedish TSO (SvK)). The “super TSO” selects balancing bids from the “bid ladder” (joint list). The local TSOs receive orders from the “super TSO” and then activate their local

<sup>2</sup>www.bmreports.com

dispatch entities [58]. Thus, the implemented model for cross-border balancing is the TSO-TSO model with common merit order list to exchange the manually activated reserves.

#### 4.2.4 The German market integration of balancing services

The implementation of recent reforms in the German control system is a good example of the TSOs' cooperation. The so-called Grid Control Cooperation (GCC) is a way to keep the decentralised control structure and extend the cooperation among TSOs. It has been proposed by German TSOs and implemented with four modules, leading to stepwise balancing market integration. The modules are as follows [42]:

- Module 1 (Imbalance netting): The aim was to avoid the activation of the secondary control reserve in the opposite direction. This was done by summing up the imbalance signals of each individual control area. The net imbalance was distributed pro rata on the control areas. The module has been implemented in Germany since December 2008, and leads to the reduction of secondary control employment.
- Module 2 (Mutual support): The main focus was the joint dimensioning and mutual support with the secondary control reserves among the participating TSOs. In the case that demand exceeds available capacity, a TSO can obtain the required balancing services from the other TSOs. The module has been implemented since June 2009.
- Module 3 (Joint procurement): In this step, a common market area for secondary control power was established. Calls for the activation of the operating reserve were carried out through the TSO where the BSP was situated. All BSPs were connected to their local TSO and approved for participation by pre-qualification through this TSO. Consequently, this module simplified the control structure and was easy to be implemented. Module 3 commenced in July 2009.
- Module 4 (Common merit order list): A system-wide merit order list of bids for operating reserves was made available, always ensuring that the next cheapest bid in the control cooperation was selected. This was the last and final aim of cooperation control. The implementation of the model was completed in October 2009.

The implementation of the above mentioned modules made the market integration significantly easier compared to the implementation based on a central

control system that would have required significant changes in the current system. With the implementation of the GCC modules, an essential cost reduction of the activated operating reserve has been achieved. The savings from the implementation of the first module alone including all four control areas is estimated to be around EUR 120 million/annum, and for both the first and second modules together it is estimated to be around EUR 140 million/annum [78]. However, the saving based upon implementing all the modules together is estimated to be around EUR 300 million/annum [78].

### 4.3 Literature Review

After having described the overview of concepts associated with the research premise in the preceding sections, it is appropriate to review earlier work reported in this area. This section is a literature survey on balancing market integration in the northern European systems. The works presented are restricted to those reported on northern European systems keeping in mind the stated scope of the research work (as mentioned in Chapter 1) in this thesis. Literature about non-European markets such as the North American and Australian markets has not been included because it has less relevance due to the fundamentally different market solutions.

Technical and institutional issues in the design and application of balancing markets have been studied extensively during the last two decades since the restructured liberalised electricity markets began. Based on the production portfolio and historical context, each individual market incorporated different nomenclature, technical requirements and procurement details for balancing services. Despite the significant difference among the features and the functional requirements of balancing markets, their fundamental aim is the same - maintaining the security of supply.

Rebours *et al.* [79, 80] give an overview of frequency and voltage control across 11 power systems from different parts of the world. The technical features of these services are studied in [79], where a basis for comparison of frequency and voltage control services across surveyed systems is provided. The economic features of these services are studied in [80], taking into account the widely varying costs of these services. The cost variations occur on the basis of the different technologies and adopted policies used to provide these services. According to Meeus [16], balancing markets range from mandatory to purely commercial markets, but as a rule payments for balancing are based on availability and grid utilisation. Heffner *et al.* [81] study five balancing power market designs including

ERCOT, United Kingdom, the Nordic system, Australia, and the PJM market. They explore the services and market arrangements in each individual balancing market and the effect of load participation in the balancing reserve. Rivero *et al.* [82] analyse the features of balancing markets across eight European power systems including the Belgian, Swiss, German, Danish, Spanish, French, Italian and Dutch balancing markets. The authors first classify control reserves used in each studied system, and present a comparison of the assessment, the balancing settlement, and the cost recovery for secondary and tertiary reserves employed by each TSO. Van der Veen *et al.* [83] give an overview of the existing balancing markets in the northern European market. They study the institutional aspects of the balancing market by evaluating the effects of market design variables on each individual balancing market. They assume that balancing markets are institutional arrangements consisting of three main pillars: balancing services provision, balance responsibility, and balance settlement. In balancing services provision, the TSO procures balancing services from different arrangements to guarantee enough balancing reserve in real-time. Balancing responsibility concerns the role of BRPs to balance their production portfolio, and balancing settlement is dedicated to determine the system imbalances and imbalance prices that BRPs have to pay to the TSOs. The aim was to investigate the effect of design variables on balancing market design. Twelve design variables were identified for balance responsibility and imbalance settlement such as: “Program Time Unit (PTU)”, “Scope of balance responsibility”, “Gate Closure Time (GCT) first energy program”, “GCT final energy program”, “Types of balances”, “Closed/open portfolio position”, “Frequency of settlement”, “Main imbalance pricing mechanism”, “Regulation states”, “Single/dual pricing”, “One/two-price settlement” and “Alternative imbalance pricing”. The results showed that the most influential design variables were the program time unit, the scope of balance responsibility, and the main imbalance pricing mechanism. Several studies have been carried out on the national northern European balancing market. In the following section, some of these studies that fall within the scope of this thesis are discussed.

### 4.3.1 The Nordic balancing markets

Skytt [84] elaborates an econometric analysis on balancing prices. He finds the correlation between balancing price, and both spot price and imbalance volume. Kristiansen [32] presents an overview of the Nordic balancing markets with a focus on the procurement of balancing services. He assesses the cost and payment system. Olsson and Söder [85] describe a combined Seasonal Auto Regressive Integrated Moving Average (SARIMA) and discrete Markov processes for forecasting real-time balancing prices. Jaehnert *et al.* [86] use a two-step long-term



and short-term model to estimate the balancing prices. The balancing state (upward or downward) is determined using the SARIMA process. The combination of the long-term model with expected balancing states and volumes is used to generate short-term scenarios of the balancing prices. Fleten and Pettersen [87] propose a stochastic linear programming model for constructing piecewise-linear bidding curves of the retailers to be submitted to the Nordic power exchange. Ravnaas *et al.* [38] derive optimal wind power bids for two sets of balancing market settlement rules: one-price and two-price settlement systems<sup>3</sup>. The optimal bid gives a better improvement in total revenues under the one-price settlement system compared to the two-price settlement system.

### 4.3.2 The German balancing markets

Riedel and Weigt [20] give an overview of the electricity reserve markets in Germany in terms of the technical requirements, the market design, and structure of the primary, secondary and tertiary reserve markets. They suggest that shorter bidding periods, especially for primary and secondary reserves, would increase market liquidity. More market players could participate in the auctions because of enhanced information about their available generation capacity. Flinkerbusch and Heuterkes [88] demonstrate potential cost reductions by pooling the German control areas for data containing bids on reserve procurement, as well as balancing power flows in the period from December 2007 to November 2008. They identify three sources of potential cost reductions: less procurement of balancing power, reduction of activated balancing power, and more efficient auctions. By netting the area imbalances and pooling all the German reserve bids, cost reductions of EUR 162.70 million are estimated corresponding to 17% of the system's total balancing cost. Möller *et al.* [89] study the design of the German balancing market, and argue that its design appears to be prone to pushing the markets' participants towards a strategic short term position in the balancing energy market. By a strategic position in the balancing market, the market participants keep their own reserve capacity rather than resorting to system reserves. Consequently, deviations will be actively managed even if an offsetting deviation exists somewhere else in the control area. This results in a highly inefficient allocation of reserve capacity by the TSOs. This happens because secondary-reserve capacity is allocated in monthly auctions, whereas tertiary-reserve capacity is allocated in day-ahead auctions for six four-hour periods. Consequently, balancing energy

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<sup>3</sup>In a one-price system, all imbalances are settled according to the balance price. The balance price is determined on the basis of the highest activated balancing market bid in the actual hour. In a two-price system the balancing price is applied in the "wrong" direction while the spot price is applied for imbalances helping the system.

prices will be less responsive to short-term hourly day-ahead prices. During periods of price spikes in the day-ahead market, it might be beneficial for a BRP to have a positive deviation, regardless of the control area's net deviation.

### 4.3.3 The Dutch balancing markets

Van der Veen and De Vries [50] study the Dutch balancing market and the effect of large-scale penetration of microgeneration on its performance. They conclude that the current design of the balancing market will handle this effect, and that there is no need for an adaptation of the market design. Van den Bosch *et al.* [90] elaborate the price-based efficient control schemes for coordinating the actions of BRPs. These schemes guarantee the overall system reliability and maximize the system benefit. It is also shown that the present way of dealing with uncertainty and disturbances is not the optimal way, and ill-suited for future challenges. As stated in [50], the present design of the Dutch balancing market could possibly accommodate microgeneration, but may not be capable of handling the uncertainties imposed on future power systems [90]. Ummels *et al.* [91] present an overview of power system balancing, including wind power in the Netherlands. They argue that sufficient interconnection capacity may allow a more system-wide coordination of secondary and tertiary reserves in the Dutch balancing market, thereby increasing the counterbalancing of imbalances throughout the system by a cross-border trading pool up to one hour ahead of physical operation. They point to the interconnection between the Netherlands and Norway (NorNed submarine HVDC cable) that could be seen as an important development regarding the use of interconnectors, and also the possible usage of Norwegian hydro power units for wind power balancing in the Netherlands. Van der Veen *et al.* [92] compare the imbalance settlement design in the Netherlands and Germany. It is opined that the imbalance pricing has more effect on both markets compared to the frequency of settlement. They also observe larger activated balancing energy volumes (more than expected based on system size) and larger imbalance prices in Germany than in the Netherlands. Abbasy *et al.* [93] carry out a similar analysis to study the performance of balancing markets in Germany and the Netherlands, focusing on the time of bidding procedure and market clearance. They conclude that different frequencies of bidding and market clearance may lead to high prices in the German market due to the fact that the indirect lost opportunity costs are added to bid prices. They recommend that the frequency of bidding should be as close as possible to the frequency of market clearance.

#### 4.3.4 Cross-border balancing studies

Madlener and Kaufmann [94] state that on a European level, balancing markets have a potential to add liquidity to the wholesale electricity trade, while at the same time not requiring additional infrastructure investments. To be able to expand their cross-border potential, European national balancing markets have to find a successful solution to some of the existing market design imperfections. A major obstacle is that national balancing markets use different arrangements for the procurement and remuneration of balancing services across Europe, impeding the EU level of electricity market integration and the creation of a single internal EU market. ERGEG [56] mentions that cross-border balancing is a “regulatory gap”. In this report, ERGEG suggests the terms and conditions for the provision of the cross-border balancing services which will need to be addressed in any future balancing market rules. Belmans *et al.* [3] propose recommendations on the optimal design and effective implementation of cross-border balancing or real-time markets. They put forward recommendations for the harmonisation of remuneration for services and the imbalance settlement for the national real-time market design. They conclude that multinational real-time market design without harmonisation of national balancing market and centralised grid security management often entails several distorting effects and inefficiencies in the multinational market. The authors also recommend the gradual implementation of cross-border balancing, taking into account only the minimum prerequisites, which will ensure faster and well-functioning execution. At later stages, the barriers hindering advanced implementation could be eliminated through further harmonisation. Weak interconnection between the well-developed national grids is pointed out as the second major obstacle in the implementation of European-wide balancing markets by Belmans and Meeus [95]. In other words, cross border electricity trade has to allocate for grid bottlenecks using different methods to account for transmission constraints and possible cuts in the transmission grid.

Vandezande [19] focuses both on the current national balancing markets in Europe and the multinational cross-border balancing markets. She suggests a proposal for appropriate national balancing market design, ensuring both market-based balancing services procurement and cost reflective real-time prices. As regards the implementation of cross-border balancing markets, she first discusses different proposals put forward by the European-wide organisation (DG ENERGY, ETSO, EURELECTRIC, and the EER). She then carries out qualitative and quantitative assessments of both the benefits and the costs of cross-border balancing market implementation. Her recommendation is to procure the reserve capacities on a short-term basis and phase out capacity payment from real-time energy prices. Four different proposals for the implementation of cross-border balancing have been studied in the qualitative assessment: the imbalance net-

ting, the TSO-BSP trading, the TSO-TSO trading limited to excess services only, and the TSO-TSO trading with common merit order. The cost reduction potential is exploited most efficiently under the TSO-TSO trading with common merit order. In the quantitative assessment, two of the proposals, i.e., the imbalance netting and the TSO-TSO real-time energy trading without common merit order, are analysed. The implementation of both proposals in Belgium and the Netherlands, resulted in a savings of EUR 17.3 million during the year 2008. Also, Vandezande *et al.* [96] show that cross-border balancing between the Netherlands and Belgium is an achievable goal that does not need unrealistic or elaborate efforts. They conclude that a significant savings can be obtained through the effect of imbalance netting and the procurement of cheaper balancing resources. The results state that an overall cost reduction of 37% could have been made by using the available transmission capacity after day-ahead market gate closure in 2008.

The European Regulators' Group for Electricity and Gas (ERGEG) [56] puts forward the principles of electricity balancing market integration. It establishes policy-related guidelines and recommendations on the integration of balancing markets in Europe. They include the roles and responsibilities of different parties, access to interconnections, contracted reserves, models for cross-border balancing, the design of balancing markets, and the transparency and monitoring of integrated balancing markets. Similar models for cross-border balancing as in [58] have been proposed and compared with each other.

Belmans *et al.* [3] propose the same approaches for cross-border balancing implementation as in [58]. They conclude that the TSO-TSO trading model is more preferable than the TSO-BSP model for cross-border balancing. They also make a distinction between the TSO-TSO real-time balancing energy trading model and the TSO-TSO reserve capacity trading model. The former approach only concerns the cross-border exchange of balancing energy in real-time, while the latter approach enables the TSOs to procure balancing services from neighbouring balancing areas. An important recommendation of this report on the harmonisation and the centralisation of cross-border balancing, which can be placed very well within the scope of this thesis, is the "need for increased grid management integration". The conclusion is that it is extremely important that the physical aspects of energy trade should also be considered in the design of integrated balancing markets. It is recommended that any development aimed at reducing the gap between commercial and physical realities is an improvement.

Van der Veen *et al.* [72] study different arrangements of cross-border balancing. They make a distinction between balancing energy trading and balancing reserve trading. The distinguishing feature is that balancing reserves require certainty on the availability of cross-border capacity trading for the entire contract

period. They investigate seven arrangements for cross-border trading. These designs are similar to those in, e.g., [56], but more focus is on arrangements for reserve capacity and balancing energy respectively, resulting in more distinct design proposals. The authors carry out a qualitative analysis for each arrangement based on designated performance criteria for cross-border balancing. The results show that ACE netting is a beneficial initial integration option, while a common merit order list is a desirable long-term goal. Van der Veen *et al.* [57] also study the regulatory challenges that arise with balancing market integration and harmonisation. They distinguish between balancing market harmonisation and integration. Similar to [3], the authors point out that two fundamental barriers to the integration of balancing markets are: required level of harmonisation of the rules and the availability of cross-border capacity for the exchange of balancing services. In relation to cross-border capacity, they recommend that it is important to have the necessary reserves in the combined balancing regions distributed in such a way that their availability is ensured, given the actual bottlenecks in the grid.

ENTSO-E [97] posits that the capacity reservation between a day-ahead market and a balancing must be permissible only if it enhances the social welfare, in which case the optimal volume allocation of transfer capacity could be determined as shown in Figure 4.7.

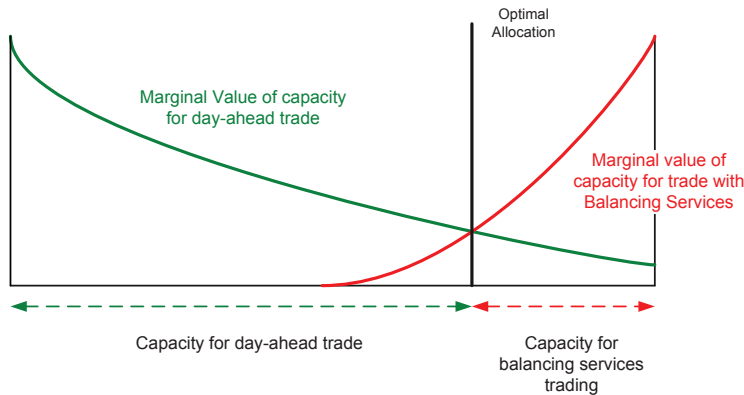


Figure 4.7: Optimal allocation of transfer capacity between two markets [97, 59]

Abbasy *et al.* [98] investigate a rough estimation of the economic value of balancing market integration in the northern European power system. They analyse the potential of balancing cost reduction. It is estimated that integration of the northern European balancing market will lead to a reduction of total balancing

cost by EUR 100 million annually. On average, it is concluded that balancing prices will stay in the same range as before the integration of balancing markets due to the congestion of interconnected transmission lines.

Jaehnert and Doorman [99] propose a model for an integrated northern European balancing power market, with the main focus on generation scheduling and unit commitment. It includes three steps of modelling - the common day-ahead market model, the reserve procurement model, and the system balancing model. Because of the system-wide procurement of reserves the procurement cost is estimated to decrease by EUR 42 million in a wet year, and by EUR 348 million in a dry year. The system balancing cost decreases due to system-wide balancing by EUR 118 million and EUR 132 million in wet and dry years, respectively. These are substantial savings. The same authors [100] study whether setting aside fixed capacity for reserve trading is beneficial or not. They employ capacity reservation on the interconnections between the Nordic region and the RG Continental Europe. It is observed that the reservation of transmission capacity for balancing reduces the socio-economic benefit of the day-ahead market by decreasing the dispatched exchange of energy between the Nordic region and RG Continental Europe. It is important to note that this is a natural consequence of the model used in the analysis. In this approach, interconnection capacity is reserved implicitly as part of the combined optimal day-ahead and reserve dispatch. Adding additional constraints necessarily increases costs in this model, although this is not a general conclusion for existing markets, see Figure 4.7.

Van der Veen *et al.* [101, 102, 103] conduct an agent-based model to evaluate the effect of four main cross-border balancing arrangements: *ACE netting*, *BSP-TSO trading*, *additional voluntary pool*, and *common merit order list*. They conclude that ACE netting and the additional voluntary pool arrangements are generally beneficial balancing market integration steps, whereas the common merit order list is the most beneficial and also the final step in market integration. Abbasy *et al.* [104] carry out a similar analysis using an agent based simulation to study the potential effect of the BSP-TSO cross-border balancing arrangement between Norway and the Netherlands taking into account risk attitudes of the market parties. The results show that the balancing prices in Norway are more resistant to market integration due to the excess of supply and a flat bid ladder. The balancing prices in the Netherlands are much more sensitive and more likely to change as a result of market integration. However, the positive effect of cross-border exchanges on the market price in the Netherlands is higher than the negative effect. In their modelling approach, the positive effect of cross-border exchange on the balancing prices in the Netherlands occurs when it imports upward balancing services from Norway. The cross-border exchange

increases Dutch balancing market prices when the Netherlands is the exporting country (downward regulation during peak hours).

#### 4.3.5 Balancing market and wind power integration

Ambitious targets have been set by the European renewables Directive 2009/28/EC<sup>4</sup>, which aims to promote the use of energy from renewable sources, by establishing an overall quota of a 20% share of renewables in gross final consumption of energy by 2020. The European Wind Energy Association (EWEA) [105] shows that in terms of total generation capacity, wind generation is expected to grow in the EU electricity system from about 65 GW in 2008 to between 230 GW (low wind scenario) and 265 GW (high wind scenario) in 2020 [105]. These ambitious targets will have profound impacts on transmission planning and system operation. Moreover, the variation and limited predictability of wind power create the need for increased production flexibility and reserve power in the power systems. Nordic hydropower, with its large reservoirs, has the favourable ability to provide large resources of balancing reserve for areas with increasing wind penetration. Thus, the integrating of balancing markets in the northern European system can facilitate the mutual procurement of flexible balancing resources.

Holttinen *et al.* [106] summarize the results of several wind integration studies carried out within the IEA Wind Task 25 Research Project. Different impacts of large scale wind power integration on power systems within the European and the U.S. systems have been studied, varying from short-term to long-term impacts. Amongst short-term impacts, issues concerning balancing power such as the short-term reserve requirements due to wind power and the balancing costs related to wind power have been studied. The studies have been carried out on each individual country depending on its production portfolio and wind power distribution. Additional short-term reserve requirements and balancing costs due to the wind power production have also been calculated according to wind penetration in each country.

Frontier Economics and Consentec [107] assess the likely cost of technological options to manage increased intermittency imposed by the integration of wind power production in the European power system. They also consider the role that interconnectors might play in managing intermittent generation by using the interconnection for cross-border provision of balancing services. Three interconnections have been studied - the NorNed HVDC link between Norway and

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<sup>4</sup><http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:en:PDF>

the Netherlands, the IFA link between France and Great Britain, and the AC link across the French-German borders. They compare the revenue earned from using an incremental 1 MW of the interconnection capacity in day-ahead market with three different alternatives using incremental capacity. The alternatives include - fixed reserving of the incremental capacity for trade in balancing services; implicit allocation of capacity by assessing whether it would be better to sell the incremental capacity in the day-ahead market or reserve for trade in balancing services; and allowing 10% overload for the exchange of balancing energy in the case of exhausting the interconnection capacity in the day-ahead market. The results of the analysis show that the latter two alternatives are more profitable than reserving the capacity for use in the day-ahead energy market.

Vandezande *et al.* [108] focus on the design of balancing markets in Europe taking into account the increasing wind power penetration. In order to optimally design balancing markets, three recommendations have been presented. First, the imbalance settlement should not contain penalties or power exchange prices. Secondly, capacity payments should be allocated to imbalanced BRPs through an additive component in the imbalance price, and finally a cap should be imposed on the amount of reserves, where the amount of reserves dampens the increasing impact on imbalance prices.

Jaehnert *et al.* [109] analyse the effect of balancing market integration on the future power system scenarios in the northern European system with the high penetration of wind power production. They study five scenarios covering the years 2010, 2015, and 2020. They propose a model consisting of the common day-ahead market model, reserve procurement, and the system balancing model for Northern Europe. The results show that through market integration, the reserve procurement cost can be reduced by as much as 50% in comparison to non-integrated cases for both 2010 and 2020. Also, a significant impact of imbalance netting has been observed in the system balancing phase.

## 4.4 Conclusions

In this Chapter, an overview of the status quo on existing balancing markets in Europe has been presented. An analysis of possible cross-border balancing models has been conducted, and some alternatives have been suggested. This is done with an aim to lay a basic foundation for the assimilation of concepts necessary for carrying out studies on European multinational balancing markets. The subsequent literature survey is restricted to the northern European systems.



It is observed that most of the literatures focuses on the design of balancing markets, and qualitative analysis of cross-border balancing. Relatively few references describe simulations and quantitative modelling, with the exception of the works by Jaehnert and Doorman [99, 100], Jaehnert *et al.* [109], Vandezande *et al.* [96], and the agent based models by Van der Veen *et al.* [101, 102, 103]. This gap in the research warranted the work carried out in this thesis. Appropriately, the thesis focuses on the quantitative modelling of the northern European balancing markets, including an aggregate grid model.

The next chapter presents qualitative models developed in the thesis for the analysis of cross-border balancing.

# Chapter 5

## Model Overview

Different models are in vogue to analyse and predict the electricity prices. These models can broadly be divided into five classes - fundamental models, financial mathematical models, game theoretical models, statistical and econometric models, and technical analysis and expert systems [110].

The first three groups exist of theoretically founded models whereas the last two are more empirically motivated models. The basic idea of fundamental models is to explain electricity prices from the marginal generation costs. These market models capture the effect of power plant characteristics and capacities, transmission capacity restrictions, and demand variations. Financial mathematical models cope with the volatility of electricity prices, and are often used for option valuation and risk assessment purposes. Originally developed for stock and interest rate markets, quite a number of these models have also been subsequently applied to the energy market field. Game theoretical models are designed mainly for analysing the impact of strategic behaviour on electricity markets. These models are used to model the competition on the electricity market. The premise is to find market equilibria being determined through the capacity setting decisions of suppliers. Statistical and econometric models capture the impact of external factors such as temperature, time of day, seasonal effects, and precipitation in hydro based systems. The models also take into account the cyclical effects which are observable in spot market prices such as hour-of-the-day effects, day-of-the-week effects and seasonal effects. On the other hand, these models are employed to analyse the interdependence of market prices and cleared volumes [84]. Methods like ARMA models, GARCH models, as well as Markov processes are included in this category [85, 86]. Technical analysis and expert systems are methods that analyse the market prices based on the analysis of past

price developments. The models in this category are adaptive models that can be trained based on the recorded market data, and can be used to forecast market prices.

A careful analysis of the applicability of these various models to the balance market integration studies points to the effectiveness of fundamental models in capturing the significant behaviour of balancing market integration. Historical data-based models cannot be representative of the post-integration scenario of balancing markets. Game theory models could be useful but add significant complexity and are outside the scope of this thesis, where perfect markets are assumed. The fundamental models - PSST, EMPS, and SecOpt, have characteristics features that are amenable to the research premise, and form the basis of this chapter.

In this chapter, the main features of existing energy market models for the northern European system employed in the thesis are briefly presented - EMPS, PSST, and SecOpt models. The EMPS model includes the modelling of water courses and hydro production in interconnected price areas. Exchange between price areas is modelled as a transport channel with a capacity equal to the total capacity of existing transmission lines between price areas, and there is no distinction between AC and HVDC interconnections. Unlike the EMPS model, the PSST model focuses on the transmission grid modelling and power flow calculation in the power dispatch. The modelling approach captures the effect of production dispatch on the transmission corridors and the exchange between nodes and areas. SecOpt gives an optimum solution to alleviate transmission congestion based on Security Constrained DC Optimal Power flow. In the modelling approach presented in the thesis, a combination of all these existing models is employed to model the balancing market in the Northern European area. On page 81, Figure 5.6 schematically represents the role and the sequence of the models used. The core of the modelling is a modified PSST using water values as an input from EMPS. The real-time dispatch has been modelled similarly to the premise used in a SecOpt model.

## 5.1 Simulation Models

In this section, a brief outline of the above-mentioned market models is presented.

### 5.1.1 EMPS model

The EMPS model (EFT's Multi-area Power Market Simulator) is a fundamental model for the optimization and simulation of a hydro power dominated system. It is developed by SINTEF Energy Research and is commonly used by the Nordic power producers and TSOs. The main aim of the model is to optimally use hydro resources by taking into account uncertain inflows, thermal generation, stochastic generation from renewable sources, and both the power demand and power exchange between the areas [111]. In the EMPS model, the simulated power system is divided into a number of interconnected areas. Each area frontier is determined on the basis of hydrological conditions and other properties of the hydro power system, as well as bottlenecks in the transmission grid and country borders. Figure 5.1 illustrates the northern European system and the division of areas. The inputs to this model include capacity and marginal cost for thermal production, as well as wind production, solar production, electricity consumption, transmission capacity, and information about historical climate variables such as inflows and temperature. In the hydro unit modelling, the inputs consist of information about existing plants, reservoirs, and waterways. The model computes an optimal strategy for hydro generation in each area during a week for each stochastic inflow scenario. The outcomes include the electricity price, marginal cost of using reservoir water, reservoir level, electricity production and covered consumption, as well as the power exchange between areas. The EMPS model consists of a two-step simulation procedure:

- Aggregated strategy for calculating water values
- A detailed system simulation based on the results from the aggregated strategy phase

#### 5.1.1.1 Aggregated strategy calculation

In the strategy phase, the expected marginal costs and water values are calculated as a function of the reservoir level and the time of year using Stochastic Dynamic Programming (SDP). It is a stochastic optimisation problem because of the stochastic behaviour of climate variables, inflow, ambient temperature, wind production, and solar production. Also, it is dynamic since the usage of hydro power from reservoirs is coupled in time. In this phase, all the hydropower units within an area are aggregated to one equivalent power station with one equivalent reservoir. Figure 5.2 illustrates the aggregated system model in the strategy phase. EMPS uses a planning period of one to five years with a time

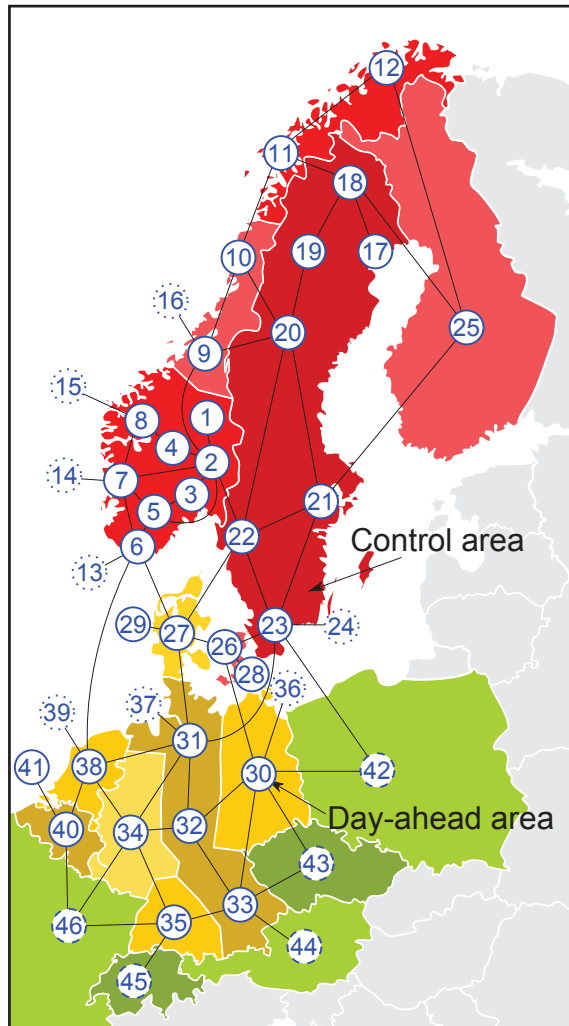


Figure 5.1: Area division for the northern European power system in EMPS model [112]

resolution of one week, and a simulation is carried out for a number of historical inflow alternatives. For every week, the goal is to minimize the operation dependent costs of generation for all the following weeks. The optimal handling of the reservoir is achieved when the total operation dependent costs are mini-

mized with regard to the energy used from the reservoir. Each week is divided into several load segments. The dual values of reservoir balancing constraint in each week are the water values for the actual week. The water values reflect the expected future value of the other types of production that the hydro generators substitute [111]. This step is essential in hydro power scheduling, since there is a limited amount of water storage in hydro reservoirs. Therefore, water value calculation is intended for the long-term strategic usage of hydro reservoirs.

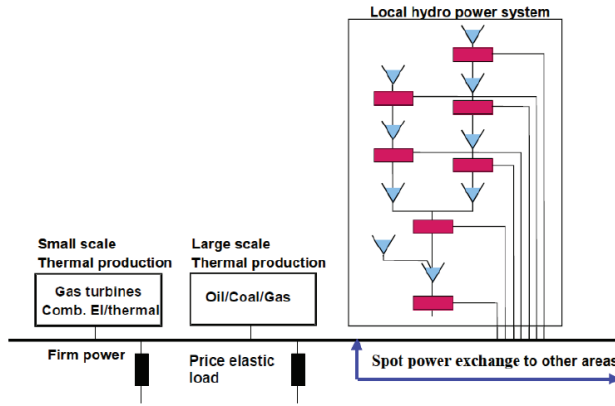


Figure 5.2: Aggregate system model in strategy calculation step of EMPS model [113]

### 5.1.1.2 Detailed simulation

In the detailed simulation phase the simulation is implemented, using the actual hydro units in each interconnected area, on the basis of the aggregated strategy calculation expressed by the simulated water values. The simulation objective is to calculate the cost minimizing operation of the hydro-thermal power system in the presence of the actual physical constraints in each specific hydropower unit, i.e., the generators' efficiency at different production levels, and hydraulic couplings in waterways. If the simulated generation in a specific area in the aggregated model is unattainable within the detailed simulation, the total production for this area will be modified in an iterative process. In the modelling approach, the power flow calculations are not explicitly modelled. The transmission between areas is modelled as an exchange variable limited by the total existing capacity, and there is no distinction between AC and HVDC transmission lines [114].

The EMPS model is used in various analyses in a hydro dominated power system such as [115]:

- Price forecast in the power market and water value calculation
- Long term operational scheduling of hydro power in large systems
- Interaction between regional subsystems
- Analysis of system expansion
- Decision supports for the usage producer's own hydro power

In the modelling approach in this thesis, the calculated water values from the EMPS model are used exogenously as inputs. They reflect the strategic usage of hydro energy at each simulation time, depending on the aggregated reservoir level.

### 5.1.2 PSST model

The TradeWind simulation model, called Power System Simulation Tool (PSST), was developed under Work Package 3 in the TradeWind project [116]. PSST is implemented in Matlab. The core of the modelling approach in the thesis is based on the modified PSST model. The original model is extended in such a way as to capture the effect of both the reserve procurement in day-ahead dispatch, and the activation of the reserve resources within the integrated northern European balancing market. Some of the main features of this model are presented below:

#### 5.1.2.1 Why flow-based model?

PSST is a flow-based electricity common market model for the whole continental Europe. Based on the laws of physics governing the interconnected transmission network, any commercial exchange between adjoining regional power markets results in a physical power flow partly on the direct inter-regional transmission lines, and partly across all available parallel paths in the network. The power flow on these parallel paths are also known as loop flows. The objective of the flow-based mechanism is to facilitate cross-border trades by providing the maximum available inter-regional transmission capacity without compromising the system security. One of the important features of electric power systems is that the power exchange is governed by the physical laws (Kirchhoff's and Ohm's laws), i.e., the power flows take several parallel paths from source to sink, based on the characteristics of the underlying network grid. It points to the fact that power

flows might not follow the contracted path in power markets. For instance, in highly meshed systems like the European electricity network, a single transaction between two countries can partly flow through other countries [117]. Therefore, a suitable method is essential to explicitly model these parallel flow paths, and to integrate the impact of cross-border commercial exchange and physical power flow. In [118], “commercial exchange” is used to describe the exchange scheduled from one market area to another as a consequence of market activity or cross-border bilateral trading. In commercial exchange, the capacity allocation is determined solely based on the market auctions and Net Transfer Capacity (NTC) values between each market area. Based on the above argument, the commercial exchange based on NTC values can fail in highly meshed power systems since they do not account for the physical laws of power grids. According to [117], flow-based capacity allocation seems to be the best answer to optimally use the existing cross-border congested transmission infrastructure. ERGEG, in [119], reviewed the current implementation of flow-based capacity allocation in both the Central-East European region and the Central-West European region, and came up with the same recommendation. Ehrenmann and Smeers [64] present the complete analysis of different proposals in European systems for market coupling and market splitting. They find that flow-based model coupling and market splitting with nodal pricing is the most efficient way to handle congestion between market areas. Therefore, with regard to the above discussion, it seems that a flow-based electric power market model like the PSST is a good choice for the European power market with its highly meshed transmission grid. Daxhelet *et al.* [120] incorporate a flow-based market model to manage the congestion of interconnection capacity between regional regulators. Uhlen *et al.* [121] present a flow-based market model that uses optimal power flow to manage congestion between market areas. The model includes a flow-based market coupling method for congestion management that can be implemented in the European power system. PSST applies the same philosophy, and models the common European energy market. In terms of pricing, the PSST is basically a nodal approach, because the optimal prices in each node result from the optimal dispatch of the system, including all constraints. However, market participants will probably be reluctant to accept nodal prices because it increases the uncertainty they face. In this connection, PSST calculates area prices based on an alternative price calculation using the weighted average of the nodal prices within each area, weighted by demand at the node [122]. The argument for the nodal and zonal pricing approach will be discussed in Paper I in Chapter 6.



### 5.1.2.2 Description of the model

PSST calculates prices in different market areas and the optimal transmission exchange between them. However, the model does not take into account the reserve requirement constraint and generators' start-up cost. In each market area, there are several suppliers and consumers, where each supplier is categorized into different types of producers, i.e., nuclear, coal (lignite coal and hard coal), gas-fired, oil, hydro, pump storage, wind, and renewables other than wind. The market is cleared at each hour of the simulation period. The model includes time dependent varying inputs such as water values, hydro inflow, load changes, and forecasted wind power variation at each hour. Production costs and capacities for all production units are given exogenously. The marginal costs of hydro units (water values) are imported from the EMPS-model. The matrix of water values is a function of reservoir level and the time of year for strategic use of hydro stored in the reservoir. Figure 5.3 shows the water value matrix for a reservoir in southern Norway.

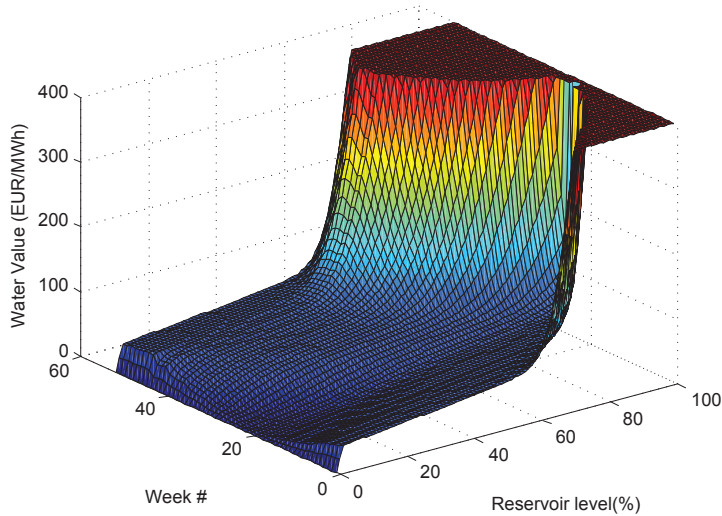


Figure 5.3: Calculated water value for a reservoir in southern Norway

Norway's water values for the first week of January have been substituted for the entire year for the countries outside the Nordic system, since no data has been available. The reason for using them for the entire year is that countries outside

of the Nordic system are not dominated by hydro production, and a special case with very low summer time water values may not be observable in these systems. The Long-term statistics for the weekly inflow in the Nordic system are available at SINTEF Energy Research [114], whereas approximate weekly inflows for the other countries have been constructed based on information from the hydrological studies “FRIEND” (Flow Regimes from International Experimental and Network Data) [123], and from [124].

In PSST, the hydrological system is not modelled in detail as in the EMPS model. The hydro generation in each area is modelled by an aggregated reservoir connected to an aggregated hydro unit. However, the transmission network is modelled in more detail using a DC power flow formulation representing the whole continental European transmission system. The grid model includes five different synchronous systems: the Nordic region, the RG Continental European region, Great Britain, Ireland, and the Baltic region (including Estonia, Latvia and Lithuania). The grid parameters together with the load and wind production series are the same as the ones used in the TradeWind EU-project [116].

The RG Continental European system model is based on the approximated UCTE network stadium 2002 created by the team of Prof. Janusz Bialek from the University of Edinburgh [125]. In the Tradewind project, the grid reinforcements since 2002 have been included. In order to study the main power flows in the system, each country has been divided into one or more zones consisting of a set of generators and buses according to their geographical location. Due to the lack of available data, apart from the Nordic and German systems, all the transmission lines within each country are assumed to have unlimited capacity. Only the lines connecting two countries have a finite capacity. Moreover, NTC values made available by ENTSO-E are set as constraints for the power flow between countries. The Nordic power system model is based on the 23-generator model of the Scandinavian power system. The 23-generator model determines the topology of the grid, and the distribution of loads and generation, and has been developed at SINTEF Energy Research based on the model presented in [126]. The simplified system model for the synchronous regions of Great Britain, the island of Ireland, and the Baltic system has been developed to reflect the actual flow of power in those systems. More details about these systems can be found in [116].

In PSST, hourly load profiles for all the areas have been collected for a given year, 2006, which is the reference for the future load scenarios [116]. The forecast load for the future scenarios is up-scaled using the relative increase/decrease and the hour by hour load profiles for the year 2006 [116, 127].

The integrated common market for continental Europe for a given time step (one hour) is solved as a linear optimisation problem, where each time step is decoupled in time. The main simulation structure is shown in Figure 5.4.

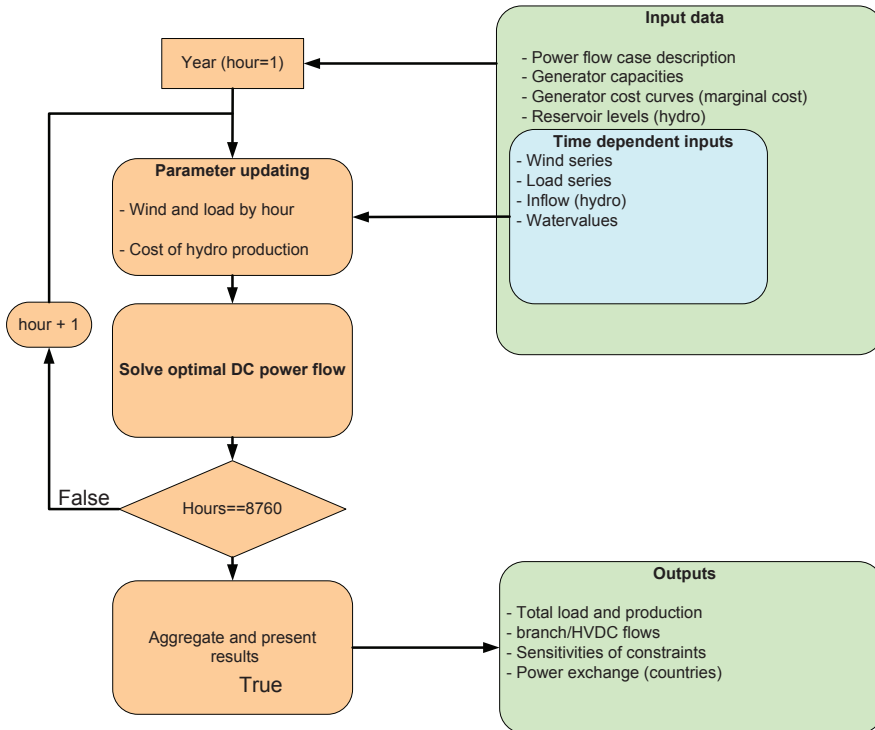


Figure 5.4: The main simulation structure [116]

The results of the optimal power flow problem are the output power of all generators and the flow on transmission lines. There is a distinction between HVDC interconnections and AC transmission lines. The HVDC exchange values are handled by controllable values between minimum and maximum cable capacities, whereas the exchange on AC transmission lines is determined by the power flow equations and physical parameters of the grid. However, they have to be within an interval between minimum and maximum capacities. The power outputs of generators are dependent on the minimum and maximum capacities, the marginal cost relative to other generators, and limitations of power flow through

transmission corridors. Clustered wind farms are modelled as generators with maximum power equal to the available wind power for a specific hour. The marginal cost is set to zero, so that wind power plants will always produce when not limited by grid constraints [116].

### 5.1.3 SecOpt model

SecOpt is the name of a prototype model for the security constrained optimal DC power flow. The formulation is based on having a base-case power flow result. The objective of the optimisation is to minimise the change in power injection. In the case of one (or several) overloaded line(s), SecOpt finds the lowest-cost possible change in power injection to remove the overload(s) [128].

An optimal power flow formulation could include power flow constraints for all transmission lines directly. However, this would make the problem quite large in large scale power systems, with respect to the number of constraints. Often a very small subset of the transmission lines will cause line flow violations. An alternative is to include line constraints where the lines become overloaded and try to alleviate congestion with the least-cost possible dispatch by changing the injected power. The result is that the number of active constraints in the optimisation gets drastically reduced, and hence the computation time as well [128].

The optimisation problem in the SecOpt-model does not include all the line constraints, but identifies line violation in an iterative scheme. Only the overloaded lines are included in the formulation. The iterative scheme is illustrated in Figure 5.5.

As indicated by dashed lines in Figure 5.5, SecOpt can also check for post contingency overloads. Two variables are added to each generation bus. One variable represents the potential reduction in power injected at the bus, and the other variable represents the potential increment in injected power at the same bus. The objective is to minimise the cost of corrective action to remove transmission overload. As shown in Figure 5.5, the LP-problem is solved for the base case power flow. If a line flow violates the thermal limits, two new variables at each production bus will be added together with a new constraint for all the overloaded transmission lines. The resulting new power flow is checked for any violation. The iteration will continue till no more lines are violated. Thus, the SecOpt model can be used to find an optimal re-dispatch from a base-case, removing any overloads on transmission lines in the base-case scenario. The model adopted for the optimisation formulation is given as:

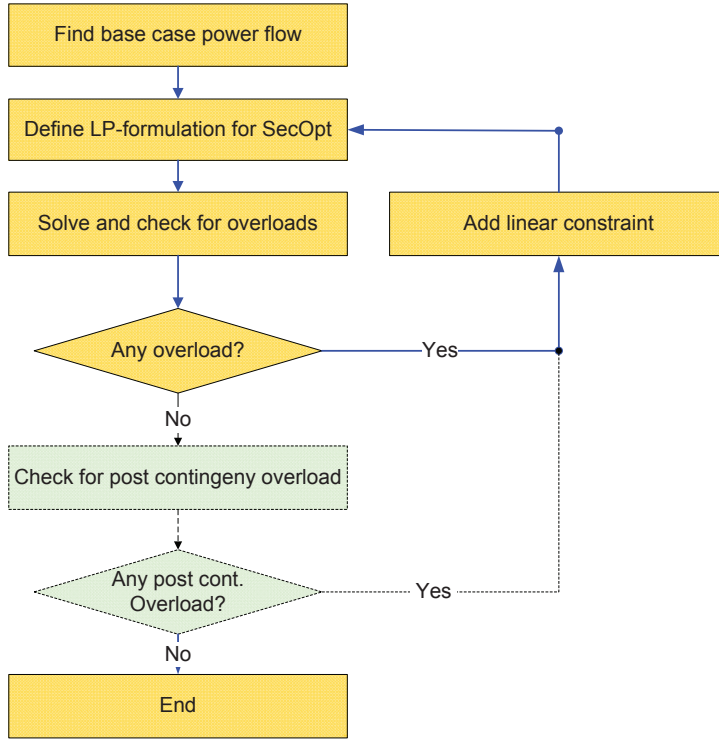


Figure 5.5: Interaction scheme in SecOpt

$$\text{Min } F = \sum_i c_i^u \Delta P_i^u + \sum_i c_i^d \Delta P_i^d \quad (5.1)$$

subject to

$$\sum_i \Delta P_i^u - \sum_i \Delta P_i^d = 0 \quad (5.2)$$

$$\Delta F_{\min}^{kl} \leq \sum_i d_i^{kl} (\Delta P_i^u - \Delta P_i^d) \leq \Delta F_{\max}^{kl} \quad (5.3)$$

where,

$\Delta P_i^u$ and $\Delta P_i^d$	The deviation from the current initial solution
$c_i^u$ and $c_i^d$	Cost coefficients (penalty terms equal 1 and -1 in this application)
$a_i^{kl}$	The sensitivity coefficient for node $i$ for line $kl$
$\Delta F_{\min}^{kl}$	Lower limits for line $kl$ in incremental model
$\Delta F_{\max}^{kl}$	Upper limits for line $kl$ in incremental model

The same approach has been used in the modelling of a real-time market in this thesis [129]. Two variables are added to each generator bus, corresponding to two hypothetical generators, representing upward and downward regulations. Instead of adding a constraint for the overloaded transmission line, the real-time imbalances in the form of wind and load forecast error will be added to Eq. (5.2). Thus, the sum of upward and downward regulation is equal to the real-time imbalances. The aim of optimisation is to follow the base-case scenario, which is a day-ahead dispatch, as closely as possible in the corrective way while minimising the balancing cost.

Figure 5.6 schematically represents the role and sequence of the models described above, leading to the overall mathematical model presented in the thesis.

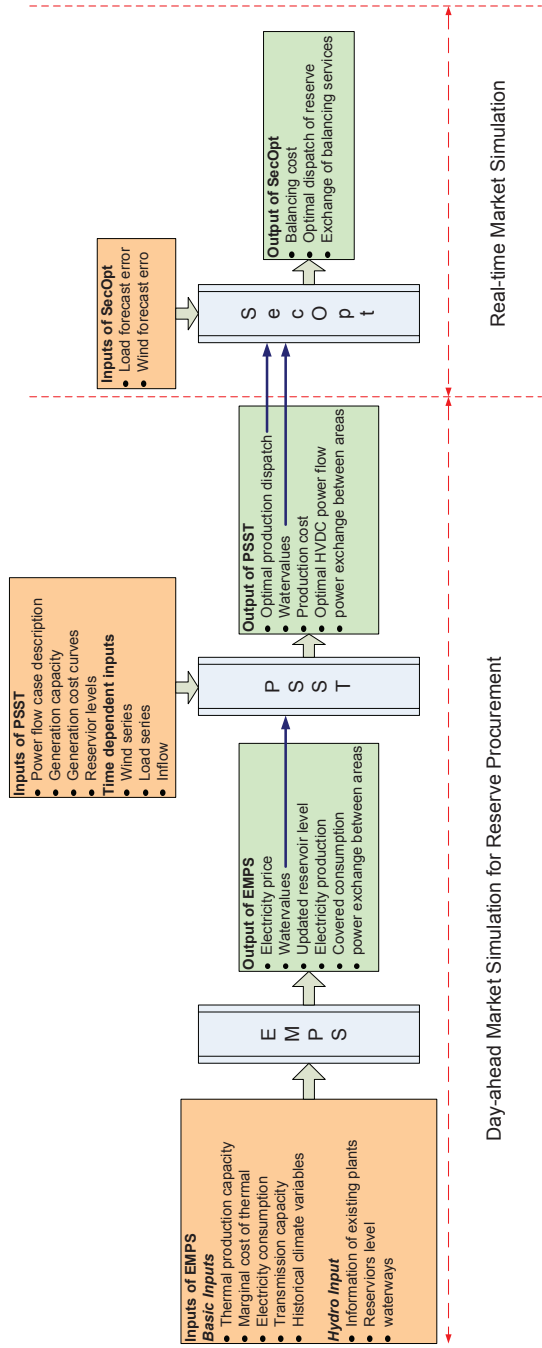


Figure 5.6: Role and sequence of the simulation models

## 5.2 Methodological Approach

In the modelling approach, a two-step model is used to estimate the benefit of integrating the northern European balancing markets and the exchange of balancing services among the Nordic countries, Germany and the Netherlands. The two steps in the model represent the day-ahead and the real-time balancing markets, respectively. The model incorporates several new features. First, it represents a common clearing of day-ahead and reserve capacity markets, taking into account grid constraints during the allocation of reserves. Next, it models the HVDC interconnections between synchronous systems, and uses these for reserve procurement and activation. Finally, it couples the above two features with a realistic (though highly aggregated) representation of the Norwegian hydropower reservoirs.

Figure 5.7 shows the modelling steps including the day-ahead and the real-time market models. The day-ahead market for the whole European continent is modelled as a perfect common market, neglecting market power issues. This means that the conditions for a perfect market in the economic sense are assumed to be satisfied. Most importantly, all generators are assumed to be price takers; they bid their marginal costs, and market power is non-existent.

Reserve procurement is limited to northern continental Europe and is done simultaneously with the day-ahead market clearing. Subsequently, the balancing energy market is modelled with a real-time power dispatch using the day-ahead market clearing results as the basis. Load forecast error and wind forecast error in the model of existing system are presented by recorded imbalance scenarios downloaded from associated TSOs' websites. For the simulation of future power systems, the wind forecast error has been added to these values.

Both day-ahead and real-time power dispatch take into account the high voltage network topology, capacity limitations on generators and interconnectors, wind power variations, hydro power characteristics, and fuel prices for different types of thermal generators.

The results of day-ahead dispatch are the power output of all generators and the flow on HVDC interconnections. The outcome of the real-time power dispatch is the optimal activation of the available regulating generators that results in both a minimum system balancing cost, and the optimal exchange of balancing services between the control areas within the integrated balancing market.

The simulation models used in different modelling steps are included in Figure 5.7. The water values as inputs to the day-ahead market are derived from



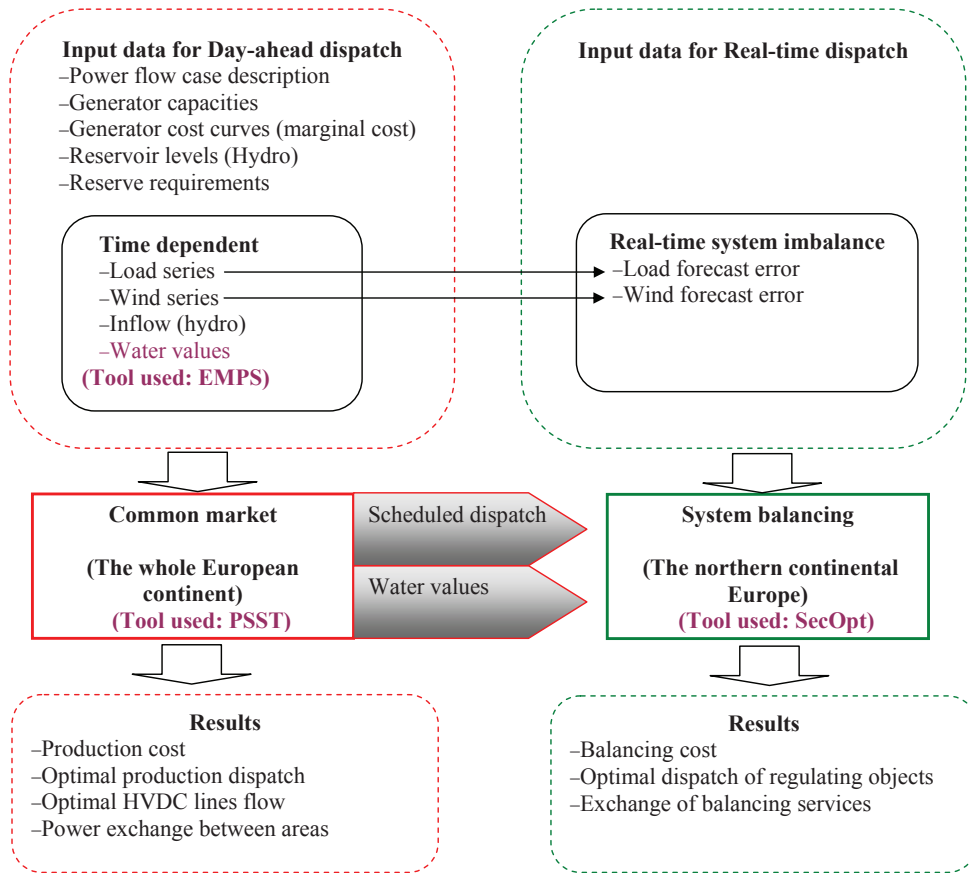


Figure 5.7: Schematic of the proposed methodology

the pre-existing EMPS model. PSST and SecOpt have been adapted to fit the requirements of the posed-problem. PSST toolbox has been modified to accommodate the model of day-ahead and reserve procurement simultaneously taking into account transmission capacity reservation for reserve exchange. SecOpt model is adapted in such a way to model the real-time reserve activation. Reserve procurement and reserve activation are the new issues modelled by these models within the scope of this PhD work.

### 5.2.1 Mathematical model for day-ahead market model

A flow-based model using DC optimal power flow (DCOPF) is used for the day-ahead market model. Eq. (5.4) expresses the cost function<sup>1</sup> for a day-ahead dispatch of a successive 24-h period. It is a piecewise linear incremental cost function, and the offered costs consist of thermal costs. These include both the start-up costs and the cost of using reservoir water that could be used for future hydro production, as well as the rationing cost for energy not supplied. The marginal cost and start-up cost of each type of thermal production in northern European area taken from the Adapt-Excel sheet as the appendix of [130]. For the other part of Europe, the marginal costs and the start-up costs are determined based upon the linear regression of those costs and production capacities. The constraints for the thermal unit start-up and hydro reservoir levels are coupled in time. The problem includes almost 300,000 variables and more than 400,000 constraints.

$$F_{\tau}^d(\cdot) = \min \left\{ \sum_{\tau \in T} \left[ \sum_{g \in G} (C_s^{th,d} \cdot St_{g,\tau}^{th,d} + C_g^{th,d} \cdot P_{g,\tau}^{th,d}) + \sum_{h \in H} (C_{h,t}^{hyd,d} \cdot P_{h,\tau}^{hyd,d}) + \sum_{i \in Bus} (C^{rat} \cdot P_{i,\tau}^{rat,d}) \right] \right\} \quad (5.4)$$

The exchange power between buses  $i$  and  $j$  is described by Eq. (5.5). Eq. (5.6) states the energy balance at each bus for a given time step  $\tau$ . Line transmission constraints are formulated by Eq. (5.7), and Eq. (5.8) limits the flows between areas to the NTC. DCOPF does not capture stability constraints, e.g., voltage stability, transient and angular stability. NTC values are established based upon detailed studies of each of the areas in the system, which account for these stability issues or Socio-political constraints. These studies are not in the scope of this thesis, and hence NTC values are considered as inputs to the model. The NTC values are available at ENTSO-E Website. The NTC constraints are considered in addition to each branch flow constraint limiting the flow between two areas. The HVDC transmission constraint is expressed by Eq. (5.9). Eq. (5.10) imposes the thermal generation limits between the maximum and the minimum production capacity. The hydro power production at each time step should also be between the minimum and the maximum production capacities. The maximum hydro production is limited by the reservoir level at each time step, as expressed

<sup>1</sup>In a perfect market context, these costs are equal to the marginal costs of the generators. In a real market context, they represent the generator's offers.

by Eq. (5.11). Inflow is divided evenly among the hours within the week, and the reservoir levels for hydro generators are updated at each time step, as formulated in Eq. (5.12).

$$P_{ij,\tau}^{Tr,d} = B_{ij} (\delta_{i,\tau}^d - \delta_{j,\tau}^d) \quad \forall ij \in Line, \tau \in T \quad (5.5)$$

$$P_{i,\tau}^{th,d} + P_{i,\tau}^{hyd,d} + \sum_{j \in Bus} (P_{ji,\tau}^{hvdc,d} - P_{ij,\tau}^{hvdc,d}) - \sum_{j \in Bus} P_{ij,\tau}^{Tr,d} + P_{i,\tau}^{rat,d} = P_{i,\tau}^L \quad \forall i \in Bus, \tau \in T \quad (5.6)$$

$$-\overline{P}_{ij}^{Tr} \leq P_{ij,\tau}^{Tr,d} \leq \overline{P}_{ij}^{Tr} \quad \forall ij \in Line, \tau \in T \quad (5.7)$$

$$-NTC_{b'a'} \leq \sum_{i \in Bus_{a'}} \sum_{j \in Bus_{b'}} P_{ij,\tau}^{Tr,d} \leq NTC_{a'b} \quad \forall a', b' \in BA, \tau \in T \quad (5.8)$$

$$-\overline{P}_{ij}^{hvdc} \leq P_{ij,\tau}^{hvdc,d} \leq \overline{P}_{ij}^{hvdc} \quad \forall ij \in HVDC, \tau \in T \quad (5.9)$$

$$\underline{P}_g^{th} \leq P_{g,\tau}^{th,d} \leq \overline{P}_g^{th} \quad \forall g \in G, \tau \in T \quad (5.10)$$

$$P_{h,\tau}^{hyd} \leq P_{h,\tau}^{hyd,d} \leq \min \left( \overline{P}_h^{hyd}, \frac{Rl_{h,\tau}^{hyd,d}}{L_\tau} \right) \quad \forall h \in H, \tau \in T \quad (5.11)$$

$$Rl_{h,\tau}^{hyd,d} = Rl_{h,\tau-1}^{hyd,d} + Q_{h,\tau}^{hyd,d} - p_{h,\tau-1}^{hyd,d} \cdot L_{\tau-1}^d \quad \forall h \in H, \tau \in T \quad (5.12)$$

### 5.2.1.1 Constraints representing start-up costs

One of the main features added to PSST through this research is the inclusion of start-up costs for thermal plants. The optimisation problem includes a large number of variables and constraints. In [131], a mixed-integer linear formulation for the unit commitment problem is presented requiring 123 s. computation time for 100 units. In mixed integer problems, the solution time scales exponentially as the problem size increases [132]. Therefore, the computation time for the current problem, including 2203 integer variables, becomes extremely high.

Thermal plants are either modelled as base-load (non-regulating) power plants such as nuclear plants, with low marginal cost and zero start-up cost, or as regulating plants providing spinning reserve. Thermal plants modelled as the latter are re-dispatched in a real-time dispatch model to compensate for imbalances. Table 5.1 shows different types of generators as regulating and non-regulating generators. The optimisation problem is extended with a simulation of the balancing markets, and solved for 365 days to yield estimations of annual results.

Table 5.1: Different types of generators

Regulating generators	Non-regulating generators
Gas	Nuclear
Oil	Lignite coal
Oil & Gas	Hard coal
Hydro	Wind
Pump storage	Renewable other than wind

It is necessary to take into account the start-up costs because the benefits of exchange between hydro and thermal systems result to a significant degree from the dynamics between high and low load conditions. As a compromise to keep the problem linear and avoid excessive calculation times, an LP based approximate algorithm is used to model the start-up costs. For the same reason, other features like ramping constraints are ignored. The approach is similar to what has been done in other studies that implement unit start-up in large-scale power systems, e.g., [133, 134, 135, 136, 137]. Each thermal plant is represented by four variables taking values from 0 to 1. The following constraints are added to the optimisation problem in order to model the start-up cost:

$$P_{g,\tau}^{th,d} = X_{1,g,\tau}^{th,d} \cdot \underline{P}_g^{th} + X_{2,g,\tau}^{th,d} \cdot (\overline{P}_g^{th} - \underline{P}_g^{th}) \quad \forall g \in G, \tau \in T \quad (5.13)$$

$$X_{1,g,\tau}^{th,d} \geq X_{2,g,\tau}^{th,d} + X_{3,g,\tau}^{th,d} \quad \forall g \in G, \tau \in T \quad (5.14)$$

$$X_{2,g,\tau}^{th,d} + X_{3,g,\tau}^{th,d} \leq 1 \quad \forall g \in G, \tau \in T \quad (5.15)$$

$$X_{1,g,\tau}^{th,d} - X_{1,g,\tau-1}^{th,d} \leq Str_{g,\tau}^{th,d} \quad \forall g \in G, \tau \in T \quad (5.16)$$

For each generation unit  $g$ , Eq. (5.13) gives the relation between the actual production and the artificial variables  $X_{1,g,\tau}^{th,d}$ ,  $X_{2,g,\tau}^{th,d}$ , and Eq. (5.14) shows that

the unit has to be started before it can produce power. Eq. (5.15) requires that the sum of the generation and the reserves above the minimum production does not exceed the maximum production. Eq. (5.16) ensures that if  $X_{1,g,\tau}^{th,d}$  increases in time step  $\tau$  compared with its value in the previous time step, the start-up cost has to be at least equal to its difference. Since the start-up cost is modelled by these linear constraints, there is no guarantee that the unit will not run between 0 and the minimum production level, i.e., the full start-up cost is always applied (partial start-up cost is possible). This is a reasonable compromise between accurate modelling and computation requirements, and has proven to result in more realistic dispatch solutions than those that leave out start-up costs altogether [133, 137]. The same approach is used by EMPS, which is a commercial model for hydro-thermal scheduling and widely used in the Nordic countries, particularly for the purpose of price forecasting, generation scheduling, expansion planning, and system analyses [114]. A similar approach has also been used in the European Wind Integration Study (EWIS) EU-project [138].

### 5.2.1.2 The Implicit allocation of the transmission capacity for reserve exchange

Another new feature added to the PSST model through this research work is the allocation of reserve in each balancing area. Based on the definition by the European Transmission System Operator (ETSO) [60] and discussion in Section 4.1.2, synchronous systems are divided into balancing regions that may consist of several balancing areas. The balancing regions can be national, such as the German system, or international such as the Nordic system. Currently, the balancing regions in Northern Europe are the Nordic system, Germany and the Netherlands. In order to handle transmission congestion within balancing areas, they are divided into sub-areas. Figure 5.8 shows the modelled balancing areas and balancing regions in the northern European system.

The balancing areas in a balancing region are connected by tie-lines, and the exchange capacity between any two balancing areas can be limited either by the capacity of tie-lines or the NTC values. However, the NTC values are assumed to be fixed throughout the year. If there is a demand for regulating resources in other areas, the availability of interconnection capacity becomes a crucial issue [139]. Therefore, the interface transfer limit on procured reserve exchange is taken into account in an optimal reserve procurement, which is determined on a daily basis as part of the day-ahead dispatch. The following equations govern the usage of transmission capacity for balancing purposes:

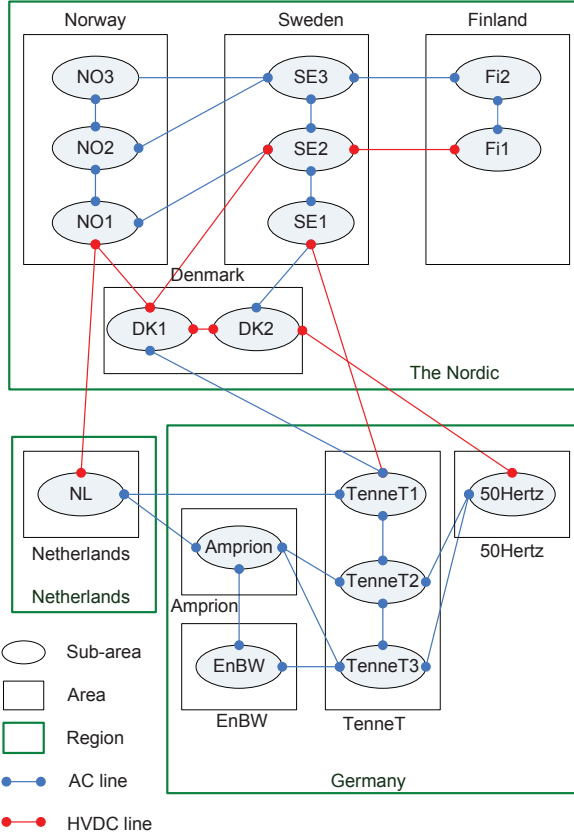


Figure 5.8: The northern continental European model

$$imp_{ab,\tau}^{up,d} \leq NTC_{ba'} + \sum_{i \in Bus_{a'}} \sum_{j \in Bus_b} P_{ij,\tau}^{Tr,d} \quad \forall a', b' \in BA, \tau \in T \quad (5.17)$$

$$\begin{aligned} & \sum_{h \in Bus_{a'}} (\bar{P}_h^{hyd} - P_{h,\tau}^{hyd,d}) + \sum_{gr \in Bus_{a'}} (X_{3,gr,\tau}^{th,d} \cdot (\bar{P}_{gr}^{th} - \underline{P}_{gr}^{th})) + \\ & \sum_{b' \in BA} imp_{a'b',\tau}^{up,d} \geq \bar{Re}_{a'} \quad \forall a' \in BA, h \in H, gr \in GR, \tau \in T \end{aligned} \quad (5.18)$$

$$imp_{ab,\tau}^{dw,d} \leq NTC_{ab'} - \sum_{i \in Bus_a} \sum_{j \in Bus_b} P_{ij,\tau}^{Tr,d} \quad \forall a', b' \in BA, \tau \in T \quad (5.19)$$

$$\begin{aligned} & \sum_{h \in Bus_a} \max \left[ \left( P_{h,\tau}^{hyd,d} - \underline{P}_h^{hyd} \right), 0 \right] + \sum_{gr \in Bus_a} \left( X_{2,gr,\tau}^{th,d} \cdot \left( \overline{P}_{gr}^{th} - \underline{P}_{gr}^{th} \right) \right) \\ & + \sum_{b \in BA} imp_{ab',\tau}^{dw,d} \geq \underline{Re}_{a'} \quad \forall a' \in BA, h \in H, gr \in GR, \tau \in T \end{aligned} \quad (5.20)$$

Eq. (5.17) defines the implicit reservation  $imp_{ab,\tau}^{up,d}$  of upward regulating power exchange capacity between balancing areas  $a'$  and  $b'$ . Eq. (5.18) requires that the sum of available reserves on all regulating units inside a balancing area, plus the import of an upward regulation opportunity from other balancing areas, exceeds the reserve requirement for that area. Correspondingly, Eq. (5.19) defines  $imp_{ab,\tau}^{dw,d}$  as an implicit allocated transmission capacity for import of downward regulating power to balancing area  $a'$  from  $b'$ . The requirement for downward regulating power is defined by Eq. (5.20).

With the present organization of the balancing market in the northern European area, there is no possibility to exchange regulating reserves between balancing regions. Hence, Eq. (5.21) and Eq. (5.22) express the upward and downward reserve requirements for each balancing region. These constraints can be relaxed depending on the level of the balancing market integration.

$$\begin{aligned} & \sum_{h \in Bus_a} \left( \overline{P}_h^{hyd} - P_{h,\tau}^{hyd,d} \right) + \sum_{gr \in Bus_a} \left( X_{3,gr,\tau}^{th,d} \cdot \left( \overline{P}_{gr}^{th} - \underline{P}_{gr}^{th} \right) \right) \geq \overline{Re}_a \\ & \forall a \in BR, \tau \in T \end{aligned} \quad (5.21)$$

$$\begin{aligned} & \sum_{h \in Bus_a} \max \left[ \left( P_{h,\tau}^{hyd,d} - \underline{P}_h^{hyd} \right), 0 \right] + \sum_{gr \in Bus_a} \left( X_{2,gr,\tau}^{th,d} \cdot \left( \overline{P}_{gr}^{th} - \underline{P}_{gr}^{th} \right) \right) \geq \underline{Re}_a \\ & \forall a \in BR, \tau \in T \end{aligned} \quad (5.22)$$

### 5.2.2 Mathematical model for real-time market model

The aim of real-time dispatch is to activate the necessary reserve to re-establish the system balance while minimising balancing costs. This reflects a market design where the objective of the balancing market is purely to relieve imbalances,

and not to create an optimal re-dispatch, as is common in several US markets<sup>2</sup>. Consequently, the so-called corrective control objective represented by Eq. (5.23) is used to minimize the deviation cost from the initial operating point [140].

$$F(\cdot) = \sum C_i |\Delta P_i| \quad (5.23)$$

where  $\Delta P_i$  is the change in production of a regulating generator at bus  $i$  and  $C_i$  is its marginal cost.

$|\Delta P_i|$  is represented by two equivalent hypothetical generators,  $\Delta \overline{P}_i$  and  $\Delta \underline{P}_i$ , modelling upward and downward regulation with incremental cost  $\overline{C}_i$  and  $\underline{C}_i$ , respectively. Eq. (5.24) shows the real-time dispatch cost function.

$$F_\tau^r(\cdot) = \min \left\{ \begin{aligned} & \sum_{gr \in GR} \left( \overline{C}_{gr,\tau}^{th,r} \cdot \Delta \overline{P}_{gr,\tau}^{th,r} + \underline{C}_{gr,\tau}^{th,r} \cdot \Delta \underline{P}_{gr,\tau}^{th,r} \right) \\ & + \sum_{h \in H} \left( \overline{C}_{h,\tau}^{hyd,r} \cdot \Delta \overline{P}_{h,\tau}^{hyd,r} + \underline{C}_{h,\tau}^{hyd,r} \cdot \Delta \underline{P}_{h,\tau}^{hyd,r} \right) \\ & + \sum_{i \in Bus} \left( C^{rat} \cdot P_{i,\tau}^{rat,r} \right) \end{aligned} \right\} \quad \forall \tau \in T \quad (5.24)$$

In addition, the following constraints must be satisfied:

$$P_{ij,\tau}^{Tr,r} = B_{ij} (\delta_{i,\tau}^r - \delta_{j,\tau}^r) \quad \forall ij \in Line, \tau \in T \quad (5.25)$$

$$\begin{aligned} & \left( \Delta \overline{P}_{i,\tau}^{th,r} - \Delta \underline{P}_{i,\tau}^{th,r} \right) + \left( \Delta \overline{P}_{i,\tau}^{hyd,r} - \Delta \underline{P}_{i,\tau}^{hyd,r} \right) + \sum_{j \in Bus} \left( P_{ij,\tau}^{hvdc,r} - P_{ji,\tau}^{hvdc,r} \right) \\ & - \sum_{j \in Bus} P_{ij,\tau}^{Tr,r} + P_{i,\tau}^{rat,r} - P_{i,\tau}^L = \widetilde{P}_{i,\tau}^{dev} \quad \forall i \in Bus, \tau \in T \end{aligned} \quad (5.26)$$

$$P_{gr,\tau}^{th,d} \leq \Delta \overline{P}_{gr,\tau}^{th,r} \leq \overline{P}_{gr,\tau}^{th} \quad \forall gr \in GR, \tau \in T \quad (5.27)$$

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<sup>2</sup>Transmission congestion in real-time is solved by the TSOs depending on the market rules in each country. A common aspect is that actions to relieve congestion should not influence the market price of balancing. The model does not relieve line overloads explicitly, but takes into account transmission constraints when re-dispatching for balancing purposes.



$$\underline{P}_{gr,\tau}^{th} \leq \Delta \underline{P}_{gr,\tau}^{th,r} \leq P_{gr,\tau}^{th,d} \quad \forall gr \in GR, \tau \in T \quad (5.28)$$

$$0 \leq \Delta \bar{P}_{h,\tau}^{hyd,r} \leq \left( \min \left( \bar{P}_h^{hyd}, \frac{R_{h,\tau}^{hyd,d}}{L_\tau} \right) - P_{h,\tau}^{hyd,d} \right) \quad \forall h \in H, \tau \in T \quad (5.29)$$

$$0 \leq \Delta \underline{P}_{h,\tau}^{hyd,r} \leq \left( P_{h,\tau}^{hyd,d} - \underline{P}_h^{hyd} \right) \quad \forall h \in H, \tau \in T \quad (5.30)$$

Eq. (5.25) states the real-time power exchange between bus  $i$  and bus  $j$ . Similar to Eq. (5.6) in the day-ahead market model, Eq. (5.26) states the energy balance at each node for a given time step  $\tau$ , taking into account the real-time imbalances. The exchange power between the buses and the balancing areas is limited using equations similar to Eqs. (5.7), (5.8) and, (5.9). In addition, Eq. (5.27) and Eq. (5.28) show the production capacity of regulating generators for upward and downward regulation, respectively. All the day-ahead values are the optimum results of the day-ahead market model. For the contributing hydro generators in the real-time reserve dispatch, similar assumptions are made as in the case of thermal regulating generators, which are represented by Eq. (5.29) and Eq. (5.30).

The real-time deviation from the day-ahead generation dispatch is completely compensated inside the balancing region as shown in Eq. (5.31). This constraint will be relaxed in subsequent analyses.

$$\begin{aligned} & \sum_{h \in Bus_a} \left( \Delta \bar{P}_{h,\tau}^{hyd,r} - \Delta \underline{P}_{h,\tau}^{hyd,r} \right) + \sum_{gr \in Bus_a} \left( \Delta \bar{P}_{gr,\tau}^{th,r} - \Delta \underline{P}_{gr,\tau}^{th,r} \right) \\ & + \sum_{i \in Bus_a} \left( P_{i,\tau}^{rat,r} \right) = \sum_{i \in Bus_a} \left( \tilde{P}_{i,\tau}^{dev} \right) \quad \forall a \in BR, \tau \in T \end{aligned} \quad (5.31)$$

### 5.3 Case studies and discussion

The balancing market model is implemented from the super TSOs' viewpoint of balancing regions to procure and employ resources in the balancing areas. The super TSOs act as single buyers in the regulating reserve capacity market. In the modelling approach, the reserve procurement is limited to the northern European area and is done simultaneously with the day-ahead dispatch. The reserve

in the model represents resources necessary for load-following, or rather “net-load-following”, where “net-load” indicates demand minus non-regulating production. In RG Continental Europe, this function is performed by frequency controlled secondary reserves [4]. In the Nordic system, only manually controlled tertiary reserves are used for this purpose [7], made possible by the favourable control characteristics of hydropower. The regulating reserves are withheld from the available day-ahead capacity during market clearing. In the actual systems, the procured regulating reserve includes both upward and downward reserves in the RG Continental European system, but only upward in the Nordic system. While in the modelling approach, the reserves are procured for upward and downward regulation in both the RG Continental system and the Nordic system. In the continental system, at most one-third of the required reserve may be procured outside the balancing area, in accordance with the operation policies of ENTSO-E [4]. In order to study the effect of balancing market integration on the reserve procurement and activation within the northern European area, two cases are studied.

- Case I: Is the reference case and represents the current state of the system. In this case, there is no possibility of exchanging balancing services between the Nordic and the continental balancing areas. Balancing services can be exchanged only between the balancing areas within the Nordic system and within Germany.
- Case II: Represents full integration of the balancing markets in Northern Europe where regulating reserves can be exchanged system-wide.

Market integration influences the operating cost both in the day-ahead and the real-time markets. It also influences the exchange energy, and the procured and the activated balancing services between balancing areas. Integration also has an implicit impact on the operating cost in the day-ahead market through the procurement of reserves in the balancing area where cheaper resources are situated. In the real-time market, the integration of larger geographical areas leads to cost savings by the so-called imbalance netting and the availability of cheaper balancing resources. Eq. (5.21) and Eq. (5.22) state the upward and downward reserve requirements for each balancing region, and these constraints can be relaxed at each level of integration. Depending on the level of integration,  $\overline{Re}_a$  and  $\underline{Re}_a$  can be changed to take into account the operation policies recommended by ENTSO-E. On the other hand, there will be one more set of similar equations for the whole balancing region, ensuring that enough reserve is procured.

The balancing reserves are procured simultaneously with the day-ahead dispatch for every 24-h period. This arrangement is captured by implementing the reserve requirement as a constraint in the day-ahead dispatch problem, see Eq. (5.21) and Eq. (5.22). In Section 5.2.1.2, the balancing services are allocated implicitly, contingent upon the availability of resources in each balancing area. If the required reserve is procured outside a control area, the availability of interconnections should be ensured in the procurement phase. This is implemented by the implicit allocation of interface for reserve exchange based on the trade-off between day-ahead energy and balancing capacity exchange. This trade-off is essential because the exchange of balancing capacity should not foreclose access to capacity when it can contribute to the economic welfare. The capacity allocated to the reserve exchange is withdrawn from the day-ahead energy exchange, which carries the risk of allocating the capacity to non-welfare maximising services and reducing the overall welfare. The model presents a market solution with a daily allocation of reserve resources in the control areas of balancing regions. ETSO in [59] addresses key issues and introduces different technical models for cross-border balancing services exchange. In [139], a framework for the trade-off between day-ahead energy and reserve exchange has been suggested. The results show that there are occasions in which there is a different social welfare arising from the use of capacity for day-ahead trade and balancing services exchange.

The real-time balancing model is implemented as an incremental power flow using the same philosophy as the SecOpt model (see Section 5.1.3), where the inputs are the results of generation dispatch after day-ahead market clearing, and the system imbalances. For real-time dispatch, the focus is on the northern European area only, i.e., it is assumed that the Netherlands and Germany maintain their ACE with other neighbouring countries in the continental system. The model's imbalances include deviations in both the load and the wind production, based on recorded imbalance scenarios in 2008 [27, 141, 17].

## 5.4 Concluding Remarks

As has been mentioned in Section 5.3, the case studies of the balancing market integration include the reference case and the full integration of balancing markets. Full integration of balancing markets will result in significant changes in balancing volumes and prices. Therefore, historical data are not representative of the post-integration scenario of the balancing market. In this connection, statistical and econometric models, as well as technical analysis and expert systems, cannot effectively capture the behaviour of the market after integration since they are mostly built on the basis of historical data. As explained in Section 5.2.1, in

the proposed model, the markets are modelled as perfect common markets, neglecting market power issues. Therefore, game theory models are not applicable in this context. Consequently, the only models which can effectively capture the behaviour of balancing market integration are the fundamental models.

The PSST model is a fundamental model for the day-ahead and balancing markets in a two stage optimisation approach. Two other models, i.e., EMPS and SecOpt have also been presented and the role and sequence of these models in the modelling implementation has been described. A methodological approach of utilising these models, the main contribution of this research, has been outlined in this chapter. In the next chapter, the results of applying this model on the existing power system and projected future markets are analysed and discussed.

## Chapter 6

# Implementation of the Proposed Models: Results and Discussion

In this chapter, the insights gained from the implementation of the models presented in the previous chapter on detailed case studies are presented along with their consequent implications. The results presented in this chapter have earlier been published in the following papers:

- **Paper I:** *Flow Based Activation of Reserves in the Nordic Power System*, H. Farahmand, S.M.A. Hosseini, G.L. Doorman, O.B. Fosso, IEEE PES General Meeting 2010, Minneapolis, USA, 25-29 July 2010.
- **Paper II:** *Modelling of Balancing Market Integration in the Northern European Continent*, H. Farahmand, G.L. Doorman, 17th Power System Computation Conference (PSCC 2011), Stockholm, Sweden, 22-26 August, 2011.
- **Paper III:** *Balancing Market Integration in the Northern European Continent*, H. Farahmand, G.L. Doorman, Applied Energy (2011), doi:10.1016/j.apenergy.2011.11.041.
- **Paper IV:** *Balancing Market Integration in the Northern European Continent: A 2030 Case Study*, H. Farahmand, G.L. Doorman, T. Aigner, M. Korpås, D. Huertas-Hernando, accepted for publication in IEEE Transactions on Sustainable Energy- special issue on application of wind energy to power system.

The author has done all the simulation work explained in the thesis, as well as the interpretation of the results and the preparation of the manuscripts. The contributions of the remaining co-authors of the papers in the above works are listed as below:

- The interpretation of the results was performed jointly in Paper I by S.M.A. Hosseini.
- Wind data was provided by T. Aigner and the interpretation of the results was done jointly by M. Korpås and D. Huertas-Hernando in Paper IV.

Additionally, four offshoots of the principal premise of the research work have resulted in the following publications:

- **Paper V:** *Modelling of Prices Using the Volume in the Norwegian Regulating Power Market*, S. Jaehnert, H. Farahmand, G.L. Doorman, 2009 IEEE Bucharest PowerTech Conference, Bucharest, Romania, 28 June-2 July 2009.
- **Paper VI:** *Optimal Wind Farm Bids Under Different Balancing Market Arrangements*, K.W. Ravnaas, H. Farahmand, G.L. Doorman, IEEE 11th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), pp.30-35, Singapore, 14-17 June 2010.
- **Paper VII:** *Impact of System Power Losses on the Value of an Offshore Grid for North Sea Offshore Wind*, H. Farahmand, D. Huertas-Hernando, L. Warland, M. Korpås, H.G. Svendsen, , 2011 IEEE Trondheim PowerTech Conference, Trondheim, Norway, 19-23 June 2011.
- **Paper VIII:** *Impact of Reserve Market Integration on the Value of the North Sea Offshore Grid Alternatives*, Y. T. Gebrekiros, H. Farahmand, G.L. Doorman, 9th International Conference on the European Energy Market (EEM12), Florence, Italy, 10-12 May 2012.

Figure 6.1 illustrates the organisation of the thesis contribution in terms of publications, and depicts the interconnectivity of the individual modules, highlighting their findings. Figures 6.2, 6.3, 6.4 and 6.5 depict panned-out views of the various modules of the thesis work, concisely explaining each of the motivational aspects and procedural highlights of the identified objectives/problem statements. As illustrated, an optimal activation procedure of reserve resources in the Nordic system is studied in Paper I. The results of two selected hours are compared to those of the current practice and the observed cost savings are used as a basis to demonstrate the effectiveness of the proposed approach. In Paper II, a newly proposed method together with the methodology to optimally procure

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balancing services is implemented for two hours in the northern European system. The quantitative profitability of balancing market integration is captured in Paper III through the implementation for a whole year of the established methodology of Paper II. Paper IV explains the implementation of the proposed models on the future scenarios of power systems with increased uncertainty in the production due to the high penetration of wind production. Paper V is not included in this thesis since historical data-based models have been used in this paper. These models cannot be representative of the post-integration scenario of balancing markets (cf. Chapter 5). Neither is Paper VI included in the thesis. It builds on Paper V and assesses the optimal bid behaviour of a wind park under different balancing market designs, which is outside the scope of the thesis. Also, Papers VII and VIII study the effect of system power losses and balancing market integration on the value of offshore grid building strategies. These two papers are considered to be beyond the scope of this thesis. In the subsequent sections of this chapter, the results of Papers I through IV are presented.

Most of the content is reproduced from the corresponding original publications. The findings of these papers have been grouped together into five distinct sub-sections in this chapter. In order to avoid the redundancy of some generic information the original content has been appropriately edited.

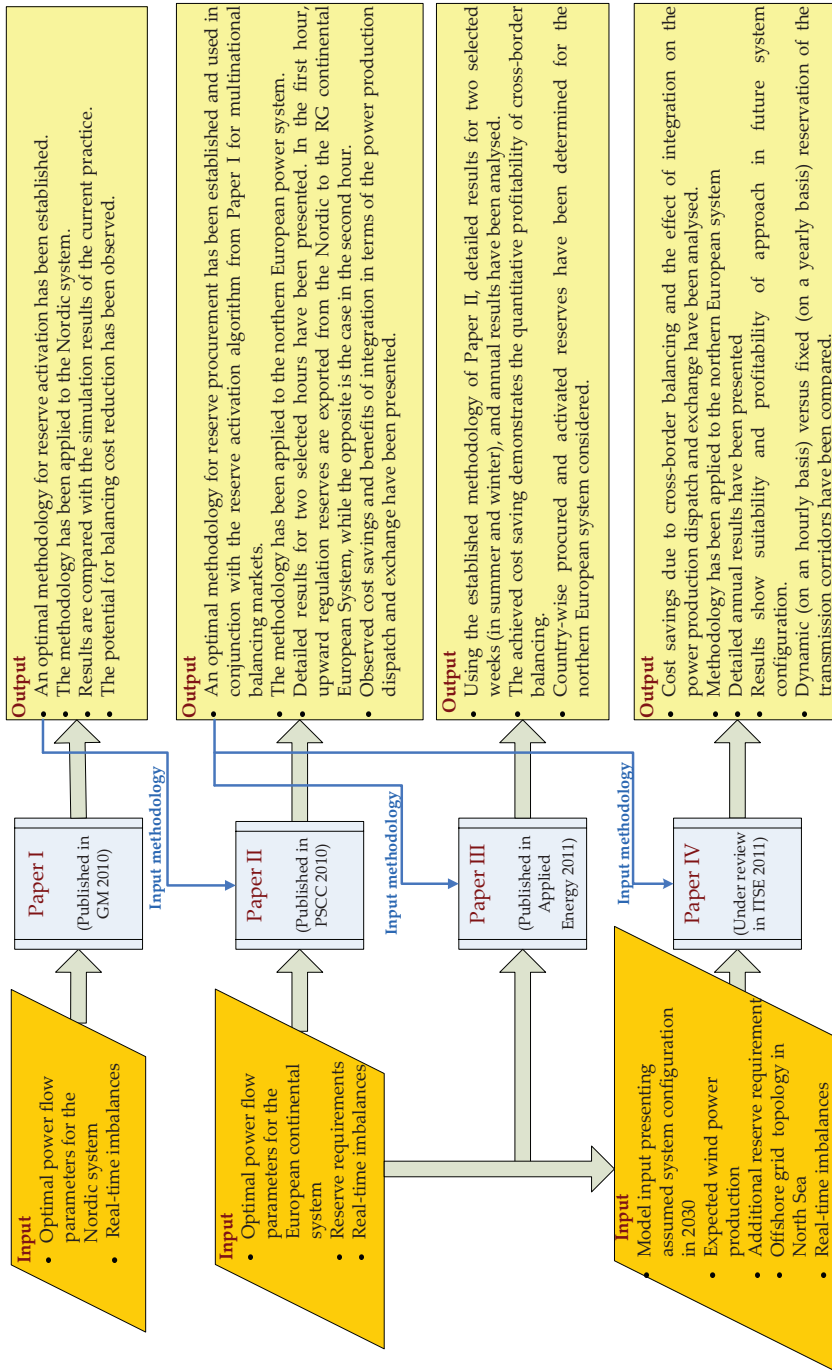


Figure 6.1: Flowchart showing the organisation of the thesis contributions in terms of publications



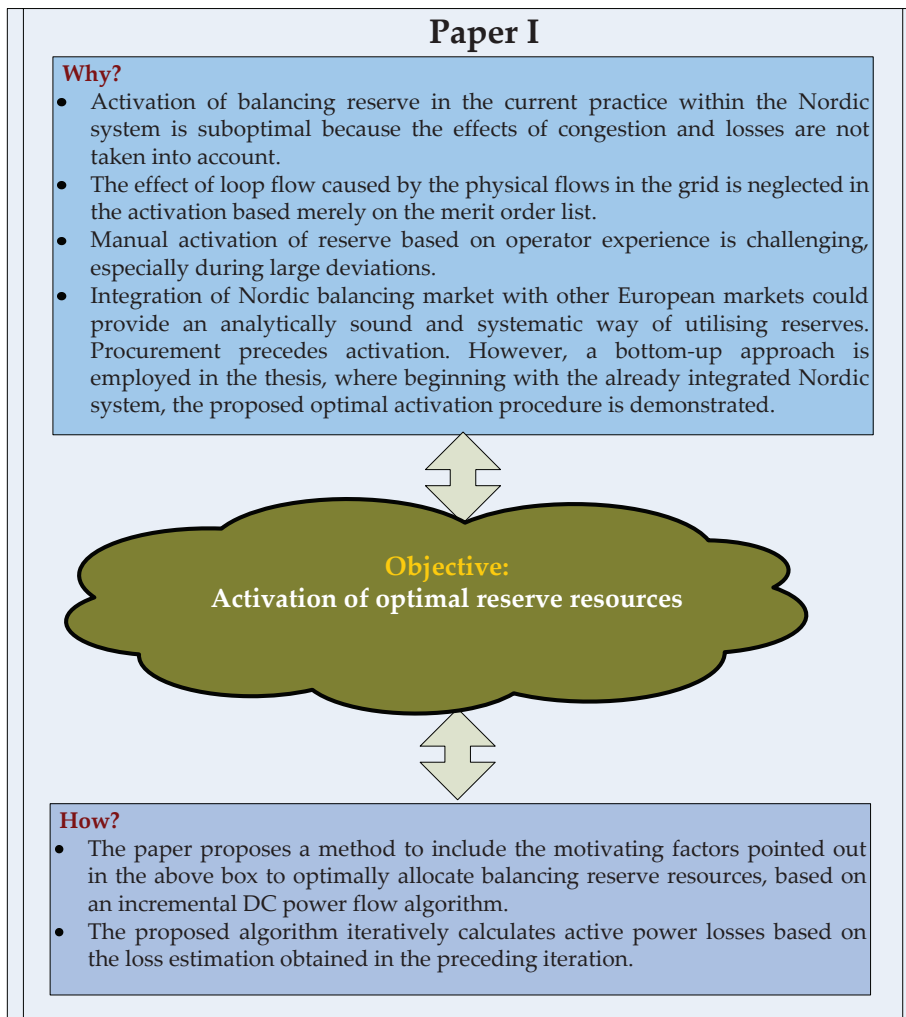


Figure 6.2: Overview of the motivation, problem formulation, and methodology of Paper I

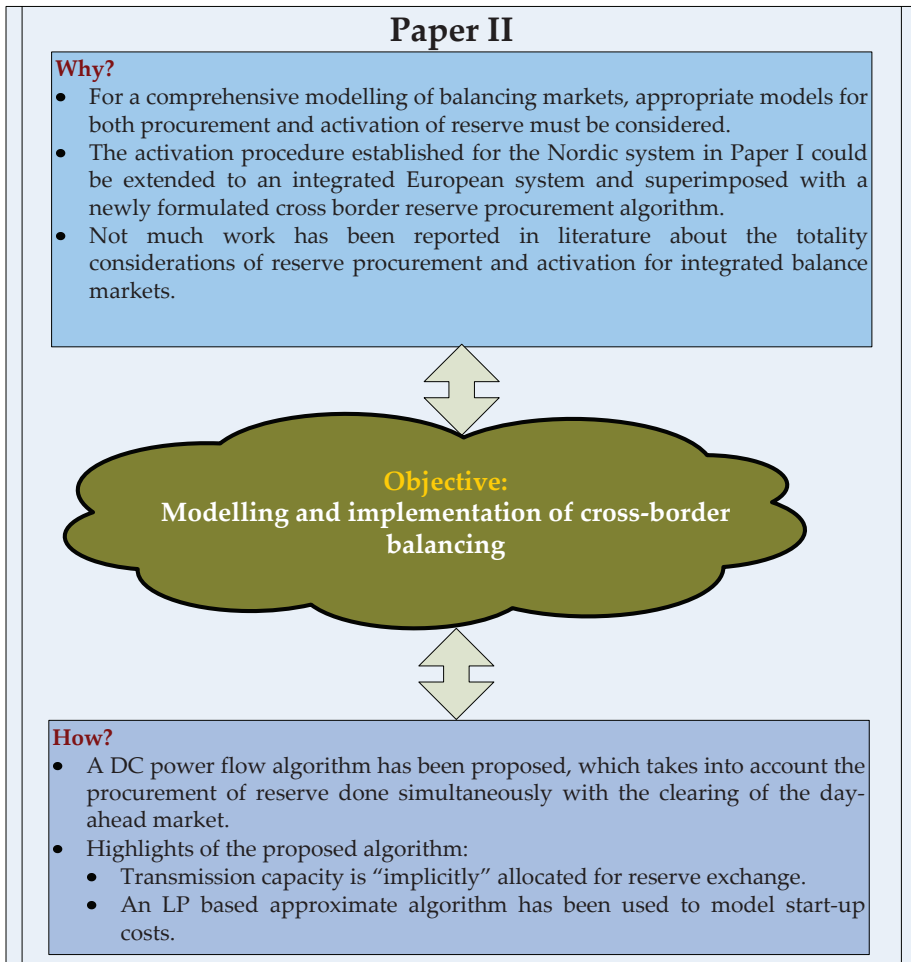


Figure 6.3: Overview of the motivation, problem formulation, and methodology of Paper II

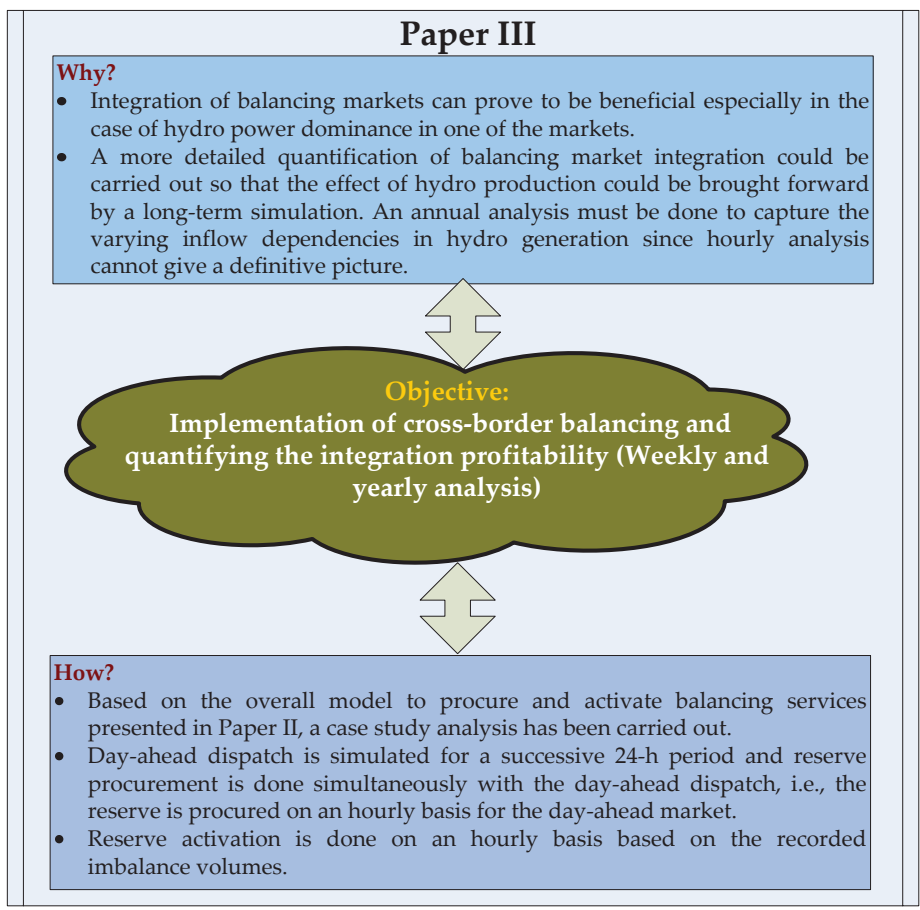


Figure 6.4: Overview of the motivation, problem formulation, and methodology of Paper III

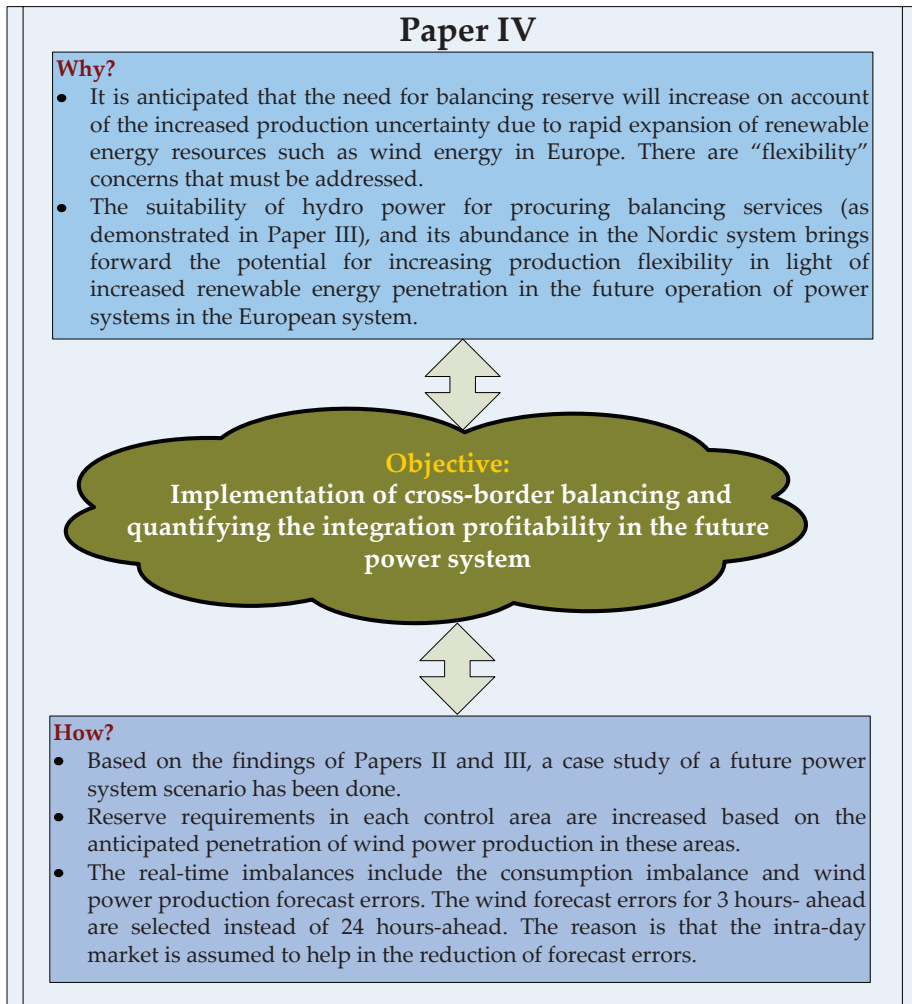


Figure 6.5: Overview of the motivation, problem formulation, and methodology of Paper IV

## 6.1 Paper I: Flow Based Activation of Reserves in the Nordic Power System

*This section is almost identical to Sections II, III and IV in Paper I. The introductory part of the paper has been reshuffled in order to fit properly in the context of the thesis and to avoid redundancy. Some changes have been made in the symbols and notations to be consistent throughout the thesis.*

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ABSTRACT. In the Nordic market, manually activated tertiary control based on bids for upward and downward regulation is used for system balancing. Although a system wide merit order list is used, the resulting regulation is suboptimal because the effect of losses is not taken into account, and transmission congestion is handled purely based on merit order list, where the bid that causes congestion is disregarded from the list. This paper proposes an algorithm for the dispatch of regulation resources based on an incremental DC optimal power flow formulation. The results of this model are compared with those of today's practice for some cases of upward and downward regulation, and a potential for cost reduction is observed. However, the method requires Automatic Generation Control that is not in use in the system, although it is presently evaluated. Pricing of regulation is also an issue, because Location Marginal Prices are probably unacceptable to market participants.

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### 6.1.1 Problem formulation and solution methodology

In the first paper, as shown in Figure 6.2, an algorithm is proposed based on incremental DC optimal power flow, and the results are compared with the simulation results of today's practice for the Nordic system. The underlying algorithm is similar to the SecOpt model [128] using a flow-based market model to dispatch the optimal activated balancing reserve within the system to compensate for real-time power imbalances. The problem as formulated, using an incremental OPF based framework for the Nordic balancing power market, is presented taking into account the active losses in the power system. According to the Nordic balancing market rules presented in Chapter 3, upward regulation will be executed by using the cheapest bid on the common Nordic list, unless this causes congestion. With the integration of balancing markets over several control areas, it becomes more complicated to assess which regulations will cause congestion, because congestion is generally more prevalent between control areas than within control areas. Also, in the case of larger cooperating balancing areas, it becomes more difficult to handle transmission congestion both within and between control areas. Increased

integration of wind power is another factor that can create larger deviations at specific locations. In general, the lowest price-bids are not necessarily those that minimize the total social cost. These considerations suggest the use of a framework based on Optimal Power Flow (OPF), which would implicitly address both aspects of the economic generation dispatch and the physical behaviour of power flow in the transmission grid. However, such an approach would raise questions about the payment for, and pricing of, balancing.

Presently, the spot market is split into several price areas with different prices for each area in the case of congestion. The balancing prices will differ if congestion between areas influences the use of balancing resources. Within each area, the balancing price is set by the marginal activated bid. This marginal price is paid to all activated resources and also paid for all imbalances, resulting in revenue neutrality for the TSO if there is no congestion. The use of OPF would implicitly result in Location Marginal Prices (LMP) in the balancing power market, which would be a major change in the market rules. On the other hand, other pricing mechanisms could be used taking into account the results of OPF.

This paper presents the formulation of incremental DC optimal power flow including system active power losses, and the results of the model implementation in the Nordic system are compared with the simulation results of today's practice. The results, as well as some possible pricing mechanisms, are discussed.

In the Nordic balancing power market, the required reserves are manually activated by the TSO based exclusively on the common Nordic merit order list of regulating reserve bids. If there is no congestion within the system, the regulating price is identical for all the subsystems. However, in the case of congestion, some of the regulating bids will be disregarded, and the balancing price for the congested area will become higher (in the case of upward regulation) or lower (in the case of downward regulation) than the other parts of the system to match the transferred power and available capacity on the interconnections. This paper studies that state of the Nordic balancing market before January 2010, where Norway was split into three, and Denmark into two price areas, while Sweden and Finland each had uniform price areas. The congestion within each area was relieved by a counter trade procedure where the TSO buys and sells at both ends of the congested line to relieve the congestion. Under this condition, since the costs of congestion and losses are not considered explicitly in the dispatch of reserves, the resulting solutions are different from the optimal dispatch of the reserve.

An alternative methodology to consider these costs in the reserve dispatch is

to use the optimal power flow for the calculation of Locational Marginal Pricing (LMP) to minimize the total operating cost. An AC based OPF represents the most accurate methodology for calculating the LMPs. Apart from being computationally expensive, the AC-OPF is difficult to implement in the current regulating market in the Nordic area. Since the LMPs are determined based on the gradient of objective function, they are very sensitive to small deviations. This would require many small control actions, which makes it difficult to implement.

An alternative to the AC-OPF formulation is to formulate the problem as a DC-OPF, focusing exclusively on real power constraints in the linearized form. The results of the DC-OPF problem can be interpreted in a more meaningful way than those of the AC-OPF in an electricity market context. As is well-known, the major approximation in a DC power flow is to neglect the line resistance and reactive power, and to assume a flat voltage profile at all nodes (all voltage magnitudes will be equal to 1.0 p.u.). More details of simplifications that are assumed in the DC power flow model are presented in Appendix A. A quadratic cost curve can be represented with piecewise-linear curves to be able to formulate the DC power flow as an LP problem. Generally the DC-OPF can be expressed as [2]:

$$\text{Min } F^d = \sum_{i=1}^{N_G} (c_i \times P_i^G) \quad (6.1)$$

subject to:

$$P_i^G - \sum_{j=1}^{N_b} (B_{i,j} \cdot \delta_j) - P_i^L = 0 \quad i = 1 \dots N_b \quad (6.2)$$

$$\underline{P}_{ij}^{Tr} \leq B_{ij} (\delta_i - \delta_j) \leq \overline{P}_{ij}^{Tr} \quad ft = 1 \dots N_{TR} \quad (6.3)$$

$$\underline{P}_i^G \leq P_i^G \leq \overline{P}_i^G \quad i = 1 \dots N_G \quad (6.4)$$

where,

$B_{i,j}$	the $i, j^{th}$ element of bus susceptance matrix ( $B$ )
$c_i$	marginal generation cost at bus $i$ (EUR /MWh)
$F^d$	objective function (EUR)
$N_b$	number of buses
$N_G$	number of generators
$N_{TR}$	number of transmission lines
$\underline{P}_i^G, \overline{P}_i^G$	maximum and minimum generation output at bus $i$ , respectively (MW)

$\underline{P}_{ij}^{Tr}, \overline{P}_{ij}^{Tr}$	maximum and minimum transmission capacity of line $ij$ , respectively (MW)
$\delta_i, \delta_j$	bus $i$ and bus $j$ voltage angles, respectively (radians)

#### 6.1.1.1 DC-OPF including marginal losses

In the case with the standard DC formulation (Eqs. (6.1)–(6.4)), the losses are neglected. However, to consider the losses in the DC-OPF, a marginal loss or incremental loss factor can be calculated. Mathematically it can be written as:

$$\rho_i = \frac{\partial P_{loss}}{\partial P_i} \quad i = 1 \dots N_b \quad (6.5)$$

where,

$\partial P_{loss}$	incremental total active losses of the system (MW)
$\partial P_i$	incremental power at bus $i$ (MW)

The total active losses are equal to the sum of the losses for each transmission line:

$$P_{loss} = \sum_{ij=1}^{N_{TR}} (R_{ij} \times I_{ij}^2) \quad (6.6)$$

where,

$I_{ij}$	flow on transmission line $ij$ (A)
$R_{ij}$	resistance of transmission line $ij$ ( $\Omega$ )



The marginal loss factor is equal to the change in system losses according to a change in the power injected or withdrawn at bus  $i$ . An alternative approach is to define a hub or a reference bus, which can be the slack bus in the system. An increase in generation in bus  $i$  by  $\Delta P_i$  will result in a decrease in the hub bus production by  $\Delta P_{ref}$  that is equal to the increase of the total active losses of the system minus the increase in generation at bus  $i$ . This can be expressed as:

$$\Delta P_{ref} = \Delta P_{loss} - \Delta P_i \quad (6.7)$$

In a lossless system,  $\Delta P_i$  would be equal to the negative of  $\Delta P_{ref}$ , whereas the flows on the system change as a result of the two generators' adjustment. This change in flow causes a change in losses. When losses are considered,  $\Delta P_{ref}$  is not necessarily equal to  $\Delta P_i$ . With this assumption, the delivery factor ( $\beta$ ) as the ratio of negative change in the reference bus can be expressed as [2]:

$$\beta_i = -\frac{\Delta P_{ref}}{\Delta P_i} \quad (6.8)$$

Substituting Eq. (6.7) in Eq. (6.8) will result in the marginal loss factor:

$$\beta_i = \frac{(\Delta P_i - \Delta P_{loss})}{\Delta P_i} = 1 - \frac{\Delta P_{loss}}{\Delta P_i} \quad (6.9)$$

or using Eq. (6.6):

$$\rho_i = 1 - \beta_i \quad (6.10)$$

Depending on the sign of the change in losses, the marginal loss factor can be positive or negative. Including this factor in the cost function of a generator will reflect the required cost of the losses arising from generator contribution to the power flow. In a market with LMPs, this marginal loss factor would be reflected in the nodal prices. The LMPs can be calculated as [142]:

$$\lambda_i = \lambda_{ref} + \gamma^L + \gamma^c \quad (6.11)$$

where,

$\lambda_i$	LMP at bus $i$ (EUR/MWh)
$\lambda_{ref}$	reference bus energy price (EUR/MWh)
$\gamma^L$	marginal cost of losses (EUR/MWh)
$\gamma^c$	marginal cost of congestion (EUR/MWh)

$\gamma^c$  is the dual value of the transmission line constraints in Eq. (6.3) which can be positive or negative depending on the flow direction. Since the flow on each transmission line is the linear combination of the contribution of all producers and consumers, the superposition theorem can be applied. Then the marginal loss between a producer and a consumer point is equal to the marginal loss between the producer and the hub, minus the marginal loss between the consumer and the hub. The linear combination of the marginal losses divided by the total load represents the marginal loss for the aggregate load. This can be written as:

$$\gamma_{P_L\_tot}^L = \frac{\sum_{k=1}^{N_L} (P_k \times \gamma_k^L)}{\sum_{k=1}^{N_L} P_k} \quad (6.12)$$

where,

$P_k$	load at bus $k$ (MW)
$\gamma_{P_L\_tot}^L$	marginal loss between aggregate load and hub point
$\gamma_k^L$	marginal loss between load $k$ and hub point

This factor can be employed in Eq. (6.11) to account for the marginal loss of generator  $i$  feeding a set of loads at different points of the system. In order to calculate the losses within a DC-OPF, an iterative process is employed where the first results from DC-OPF are considered as initial results to estimate losses. The allocated loss on each transmission line is then calculated based on Eq. (6.5). Half of the losses are added at each end of the line [142] as shown in Figure 6.6. In practice, the grid losses are bought in the spot market by the respective TSOs and paid for by the market participants through the grid tariffs. A weekly updated point tariff is based on average losses during day and night periods, respectively [7], and can be viewed as a coarse approximation to LMP.

These estimated losses will be used to obtain a new dispatch. This process is repeated until the results between two iterations are within a certain tolerance. The results from this iterative process and an AC-OPF are very similar, while the DC-OPF is faster [143].

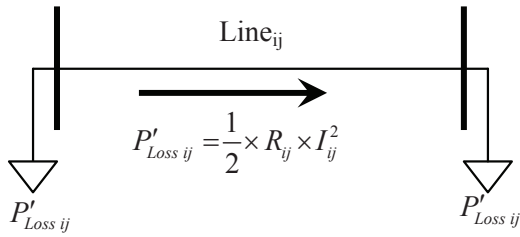


Figure 6.6: Loss represented as loads at both ends of transmission line

### 6.1.1.2 IDC-OPF considering marginal losses

A balancing market deals with the real-time reserve dispatch to maintain the balance between production and consumption caused by, e.g., deviations between forecast and actual demand or generation outages. In real time, the basis for the calculations would be the actual situation in the system as indicated by the state estimator. However, in a model approach, the basis can be an assumed day-ahead spot market dispatch. Subsequently, an incremental optimization approach can be used to minimise the cost of compensating for deviations from the initial market balance.

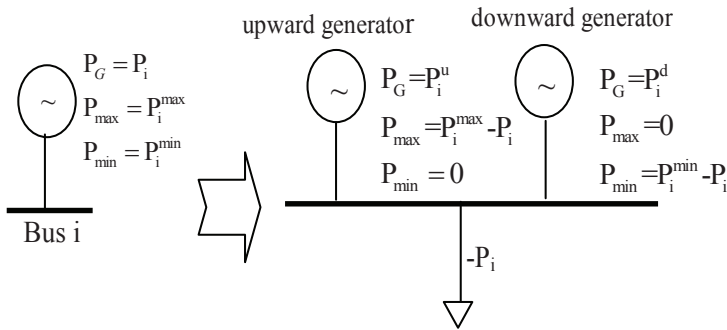


Figure 6.7: Generators represented in IDC-OPF

The Incremental DC-OPF (IDC-OPF) formulation that is employed takes into account grid congestion and marginal losses when determining the optimal dispatch of regulation resources. Figure 6.7 illustrates how each generator contributing in real time reserve dispatch is modelled as a fixed negative load, representing the spot dispatch ( $-P_i$ ) and two hypothetical generators represent-

ing upward and downward regulation, respectively. The IDC-OPF model can be formulated as below [128]:

$$\text{Min } F_{IDC} = \sum_{i=1}^{N_G} (\hat{c}_i^u \cdot \Delta P_i^u) + \sum_{i=1}^{N_G} (\hat{c}_i^d \cdot \Delta P_i^d) \quad (6.13)$$

Subject to:

$$\Delta P_i^u - \Delta P_i^d - \sum_{j=1}^{N_b} (B_{i,j} \cdot \hat{\delta}_j) - P_i^L = P_{dev} + P_{loss} \quad i = 1 \dots N_b \quad (6.14)$$

$$\underline{P}_{ij}^{Tr} \leq B_{ij} (\hat{\delta}_i - \hat{\delta}_j) \leq \overline{P}_{ij}^{Tr} \quad ij = 1 \dots N_{TR} \quad (6.15)$$

$$0 \leq P_i^u \leq \overline{P}_i^G - P_i \quad i = 1 \dots N_G \quad (6.16)$$

$$-P_i \leq P_i^G - P_i \leq 0 \quad i = 1 \dots N_G \quad (6.17)$$

where,

$\hat{c}_i^u, \hat{c}_i^d$	upward and downward marginal generation cost at bus $i$ , respectively, including marginal losses (EUR/MWh)
$P_{dev}$	real-time deviation (MW)
$P_i$	committed generation capacity at bus $i$ (MW)
$\Delta P_i^u, \Delta P_i^d$	upward and downward incremental generation at bus $i$ , respectively (MW)
$\hat{\delta}_i, \hat{\delta}_j$	bus $i$ and bus $j$ voltage angles, respectively (radians)

### 6.1.2 NORDIC power system & PSST model

The description of the Nordic system has been presented in Section 3.1. Table 3.1 illustrates the dominating position of hydropower. The favourable characteristics of hydropower in general and the highly storable Norwegian hydropower specifically, make this technology a perfect candidate for the provision of balancing services. This property will become more and more required with the increasing integration of wind power in the Nordic system, as well as the RG-CE system. However, increased use of hydropower for balancing purposes increases the need for a more efficient use in the context of system balancing.

There are a number of HVDC cables between the Nordic system and the RG Continental European system, cf. Table 6.1.

Table 6.1: HVDC cable connections between Nordic and central European power system [23]

Countries/ Cable name	Rated voltage (kV)	Transmission capacity (MW)	
		From <sup>1</sup>	To <sup>2</sup>
Sweden-Poland (SwePol)	450	600	600
Sweden-Germany (Baltic)	450	600	600
Denmark East-Germany (Kontek)	400	600	600
Sweden- Denmark West (KontiSkan)	2×285	740	680
Norway- Denmark West (Skagerrak)	250/350	1000	1000
Norway-The Netherlands (NorNed)	450	700	700

<sup>1</sup>Transmission capacity from the first country listed.

<sup>2</sup>Transmission capacity to the first country listed.

In addition to the cable interconnections shown in the above table, several new ones are being planned or studied [10]. This creates an increasing opportunity to use Norwegian hydropower for balancing purposes in RG Continental Europe.

As explained in Chapter 3, fast active reserve in the Nordic power system is activated manually, where the cheapest regulating bid is selected from a common merit order list irrespective of nationality, provided the grid has no congestion problem. In the case of congestion in an area, some of the regulating bids will be disregarded and regulating prices will be different from other areas [144].

Manual activation of reserve based on human operator experience has worked satisfactorily in the Nordic system so far, although following the large (net) load increases during the morning hours, especially in the wintertime, can be challenging. This is caused by the fact that the daily exchange with the RG-CE system has the characteristics of a pumped storage scheme, where Norwegian hydropower is exported during the daytime, while cheap thermal low load power is imported during the night. An increasing exchange of both peak and balancing power introduces the need for a more sophisticated methodology for dispatch of activated reserves. It may also become necessary to introduce automatically activated secondary reserves. The proposed IDC-OPF based model for the balancing

power market can be used as a key to solve these challenges.

### 6.1.3 Simulation and results analysis

In this section, the comparison of the results of using the proposed model for balancing in the Nordic system with the present practice is presented. Simulation of the balancing market must be started with a day-ahead system dispatch, which is established in two steps:

1. Calculation of the market dispatch, based on a zonal model with 6 nodes in the Nordic system (Western Denmark is considered as a part of the RG-CE system in the model). This results in different zonal prices, whenever there is congestion between zones.
2. The zonal dispatch may result in congestion within zones. In the market, such congestion is relieved by counter trade as explained in Section 6.1. In the model, this is approximated by using a DC-OPF model. This may result in different marginal costs at different buses within the same zone.

To establish the base case situation, the PSST model is used. As pointed out in Chapter 4, the model simulates the flow-based market model throughout the whole continental Europe taking into account wind power production scenarios. In step 1, the Nordic system is modelled by a highly aggregated model with six nodes representing each price area in the day-ahead market. To relieve intra-zonal congestion (step 2), a more detailed model of the Nordic system is used, shown in Figure 6.8.

This model has 41 buses with 23 generators [126]. At the generator buses, a total of 35 generators are connected, because different technologies are represented by different generators wherever applicable. For example, there are 6 generators connected to bus 7000 (representing Finland), each of them representing a specific technology such as nuclear, hydro, gas, lignite, etc.

For the simulation of the balancing power market, a typical peak load day in wintertime has been selected. Figure 6.9 presents the forecasted Nordic load on the second Wednesday in February 2010 [23]. As the figure shows, there is a fast increase of the load demand from 59 to 63 GW between hours 7 and 8. Between hours 19 and 20, there is a decrease of 1000 MW. It should be noted that large changes on the interconnections with the RG-CE system will occur at the same time, and that the Norwegian generation system will take up a large share

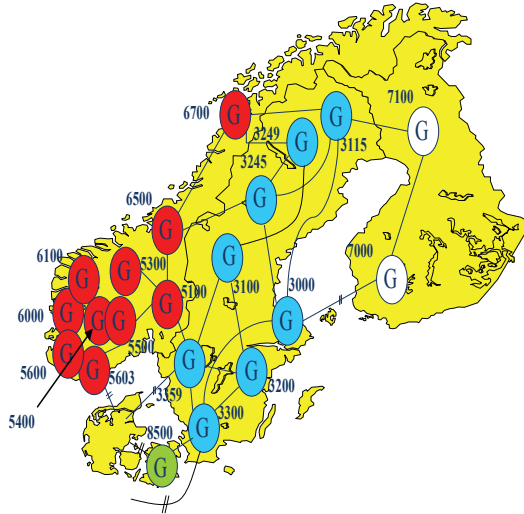


Figure 6.8: The Nordic power system [116]

of these changes, making considerable requirements to the ability of the control systems in the Norwegian system. The greatest deviations with the day-ahead dispatch plans therefore typically occur during these hours. Hence, the demand in hours 8 and 19 is used as the basis for the calculations.

An earlier study modelling the need for regulation power [86] estimated the expected deviations in the Nordic system. These were assumed to occur in the major load areas of Oslo (bus-5100) in the Norwegian power system, and Stockholm (bus-3000) in the Swedish power system, and were taken as the basis for the subsequent analyses.

#### 6.1.4 Day-ahead dispatch

The generator bids were approximated by assumed fuel costs and water values in the case of hydropower. Figure 6.10 shows the balancing market merit order list, and also indicates the total load of 63572 MW in hour 8 and 62848 MW in hour 19. Without congestion, there would be one system price given by the most expensive running generator on this list.

However, congestion between the areas occurs, resulting in different zonal

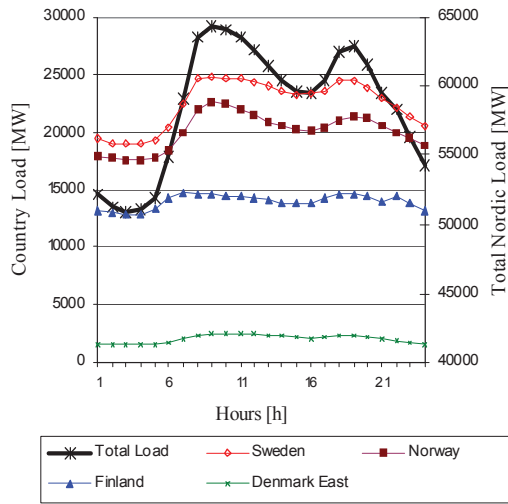


Figure 6.9: Forecast hourly load on the second Wednesday in February 2010 [23]

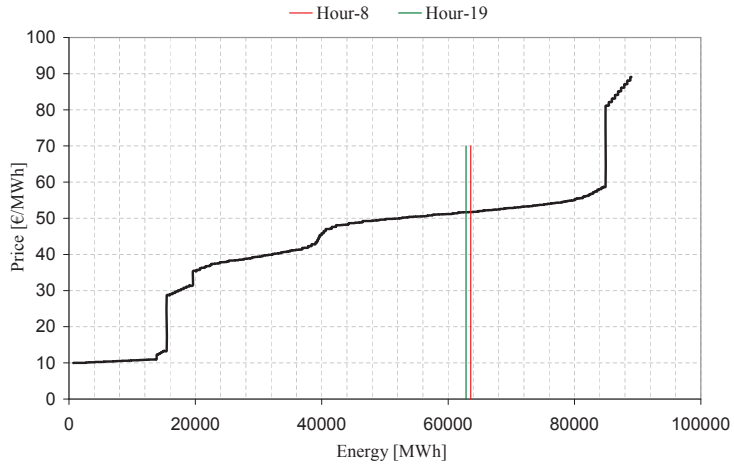


Figure 6.10: Nordic merit order list for hour 8 and 19 in the morning



prices as shown in Table 6.2.

Table 6.2: Zonal prices in hour 8 and hour 19

Area	Price (EUR/MWh)	
	Hour 8	Hour 19
SE (Sweden)	51.44	52.07
NO1 (South of Norway)	49.91	50.41
NO2 (Mid Norway)	42.67	43.06
NO3 (North of Norway)	37.63	37.91
Fi (Finland)	51.44	52.07
DK-E (Eastern Denmark)	50.05	50.63

In order to relieve intra-zonal congestion, it is necessary to do a re-dispatch, which models the TSO counter-trading within control areas. This results in the dispatch and prices given in Table 6.3.

Table 6.3: Marginal costs after counter trading in hour 8 and hour 19

Zone	Gen#	Hour 8		Hour 19	
		Power (MW)	Price (EUR/MWh)	Power (MW)	Price (EUR/MWh)
SE	3000	5477	10.94	5477	10.93
	3000	868	51.14	868	51.84
	3100	1860	52.04	1860	52.95
	3115	3967	52.84	3967	53.47
	3200	362	10.93	362	10.93
	3245	1674	50.98	1674	51.67
	3249	4091	51.88	4092	52.68
	3300	519	41.08	519	41.07
	3300	1369	51.01	1597	51.60
3359	3617	10.92	3617	10.92	
NO1	5100	1757	53.26	1465	53.67
	5300	2237	30.00	2237	30.07
	5400	1855	48.00	1855	48.68
	5500	976	51.21	1139	52.53
	5603	2319	48.77	2319	49.42
	5600	98	50.69	81	50.80
	6000	1822	39.15	1822	39.44

Continued on next page

**Table 6.3 – continued from previous page**

Zone	Gen#	Hour 8		Hour 19	
		Power (MW)	Price (EUR/MWh)	Power (MW)	Price (EUR/MWh)
	6100	3303	40.91	3775	41.74
FI	7000	4271	10.99	4271	11
	7000	3400	41.14	3400	41.16
	7000	3000	52.84	3000	52.86
	7000	1200	45.33	1200	45.34
	7100	1741	52.35	1741	53.04
DK-E	8500	1451	41.30	1451	41.29
	8500	1024	50.05	1536	51.22

The dispatch for the zone SE (Sweden) is almost the same for both hours, because the load is very similar and there is congestion in areas with lower costs, cf. Table 6.4.

Table 6.4: Exchanged power between price areas

From	To	Capacity(MW)	Exchanged Power(MW)	
			Hour 8	Hour 19
NO1	SE	1000	1000	1000
NO2	NO1	500	100.44	106.87
NO2	SE	500	290.84	303.06
NO3	NO2	1000	472.9	442.36
NO3	SE	600	600	600
SE	Fi	1200	1174	876.48
SE	DK-E	1350	1350	1350

### 6.1.5 Activation of reserves based on merit order list

In order to model the present practice of the Nordic balancing market, the cheapest generator's bid is selected exclusively from the merit order list without causing congestion. The results are shown in Table 6.5.

Table 6.5: Results of manual regulation

Case#	Imbalance(MW)	Bus#	Corrective action			
			Gen#	Production (MW)	Price (EUR/MWh)	Cost (EUR)
1	+187	5100	5100	187	53.88	10075
2	+123	3000	3000	123	52.78	6492
3	-147	5100	5600/5603	-146	49.42	-7260
4	-101	3000	3000	-101	48.87	-4936

### 6.1.6 Simulation results using the IDC-OPF model applied in Nordic system

The algorithm described in Section 6.1.1 to find the optimal regulation for each of the four cases is implemented in this section. Table 6.6 shows the dispatch of the activated balancing reserves.

Table 6.6: Optimal regulation results(MW)

Gen#	Case 1	Case 2	Case 3	Case 4
3115	-	30.38	-	-14.10
3245	-	3.74	-	-
7000	-	45.01	-	-
7100	-	34.10	-	-53.14
5100	132.20	-	-107.77	11.46
5300	-5.02	-	-	-
5500	40.57	-	-	-
5600	2.45	-	-	-
5603	16.27	-	-	-
6700	-	9.88	14.44	8.98
6500	-	-	-54.11	-54.11
<b>Sum</b>	<b>+186.47</b>	<b>+123.11</b>	<b>-147.44</b>	<b>-100.91</b>

It can be seen from Table 6.6 that instead of large steps over one or two generators, the regulation is spread with relatively smaller steps over several generators. To some extent this is caused by congestion, and also by the fact that losses are taken into account. As shown in Table 6.5, in the first case the activated reserve

is lower than the deviation, which means that this dispatch pattern decreases the total system active losses and the required activated reserve will become lower. Prices are listed in Table 6.7 at the buses where the reserve resources have been activated.

Table 6.7: Prices at production and consumption buses (EUR/MWh)

Gen#	Case 1	Case 2	Case 3	Case 4
3115	-	52.74	-	49.09
3245	-	50.88	-	-
7000	-	52.25	-	-
7100	-	52.25	-	50.41
5100	53.03	-	51.08	53.52
5300	28.50	-	-	-
5500	51.38	-	-	-
5600	49.25	-	-	-
5603	50.77	-	-	-
6700	-	38.39	38.61	38.63
6500	-	-	47.50	46.99

The balancing costs in different cases are compared with that of the current situation of the market based on merit order list and presented in Table 6.8.

Table 6.8: Balancing cost comparison in the different methods of reserve activation (IDC-OPF and merit order list)

Case#	Balancing cost (EUR)		Difference (EUR)
	IDC-OPF	Merit order list	
1	9917	10075	-158
2	6306	6492	-186
3	-7458	-7260	-198
4	-4953	-4936	-17

The results in the above table indicate that the IDC-OPF algorithm will dispatch the reserve more efficiently than the merit order list method, and this could result in significant cost reductions in the long-term running of the system.

### 6.1.7 Discussion

In the existing market solution, the cost of losses and congestion is not explicitly considered. Using some examples of the regulation of moderate deviations, it is shown that an optimization model, using an IDC-OPF algorithm taking into account the losses, results in a lower cost of regulation. Instead of using one or a few generators for the regulation, four to six generators are used in the optimal solution.

Two issues must be discussed in this context. First, with today's manual dispatch of tertiary reserves it would not be possible to change the set-point of many generators at the same time. The proposed solution would require the use of secondary control based AGC to be feasible. Next, there is the issue of pricing in the balancing power market. Today, all activated generators get paid the marginal price for regulation in the actual hour, while all BRPs pay the same marginal price for their imbalances. There may be different prices between the zones if congestion limits the use of balancing power on a system wide basis. The use of OPF in the balancing market in principle results in LMPs for balancing power (it must be noted that zonal prices in the day-ahead market can still be used). However, market participants will probably be reluctant to accept LMP because it increases the uncertainty they face. Other alternatives are possible, but they are in principle sub optimal (because different market participants face different prices). Differences between prices paid to the providers of regulation and prices paid for imbalances also affect the revenues and costs of the TSO, which warrant a careful analysis.

## 6.2 Day-ahead Market Model in Continental Europe Using PSST Model

*The results in this section are not a part of published papers, but have been included because they demonstrate the viability of the PSST model with respect to representing realistic prices for the northern European power system.*

The day-ahead market is modelled as a common market for the whole European continent using the PSST model (cf. Section 5.1.2). The model includes 101 generators in the Nordic system and 409 in the northern European (NE) area. The basis of modelling is the model presented in Section 5.2.1. In order to illustrate the characteristics of the model, the day-ahead results are presented for two typical weeks in winter (week 6) and summer (week 28). The system of 2010 without the exchange of balancing services between the Nordic and RG-CE

systems is selected for these illustrations.

Figure 6.11 shows a comparison between hydro generation dominated Norwegian spot prices versus thermal generation dominated German spot prices. The spot prices in the German system are lower than Norwegian prices during the low load hours (nights and weekends), while they are higher during peak load hours, where the peaking units have been started up. Comparison between Figure 6.11a and Figure 6.11b indicates that there is a high variation in the German spot prices between load periods (e.g., weekdays, weekend, peak and off-peak hours) whereas Norwegian prices show little variation within a week. However, there is more variation between Norwegian prices in winter and summer, caused by the variation in seasonal inflows and demand. Comparison between Norwegian and German prices shows the scope for energy/reserve exchange from a system in low price period to a system in high price period.

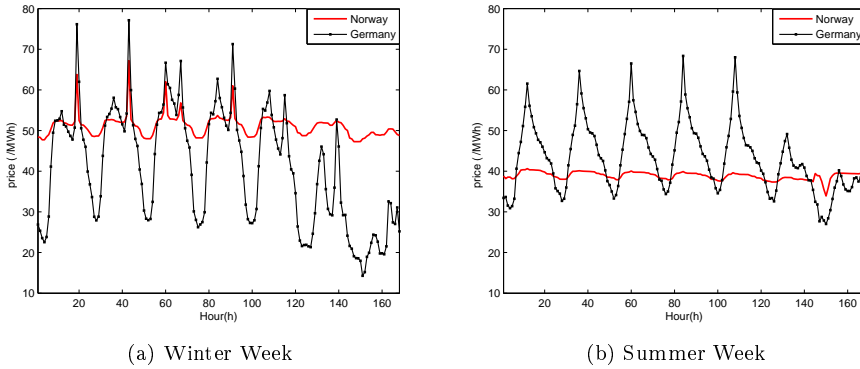


Figure 6.11: Day-ahead spot prices

Figure 6.12 presents the exchange of energy between the Nordic and RG-CE power systems. There is an export from the RG-CE system to the Nordic system during off-peak hours, and export to the RG-CE system during peak hours in the winter week. This is due to the effect of energy prices shown in Figure 6.11. The actual energy exchange in the course of a week depends on the hydrological situation in the Nordic system.

Figures 6.13a and 6.13b represent the detailed dispatch of production in the German system during both summer and winter weeks. The colours indicate

## 6.2. Day-ahead Market Model in Continental Europe Using PSST Model

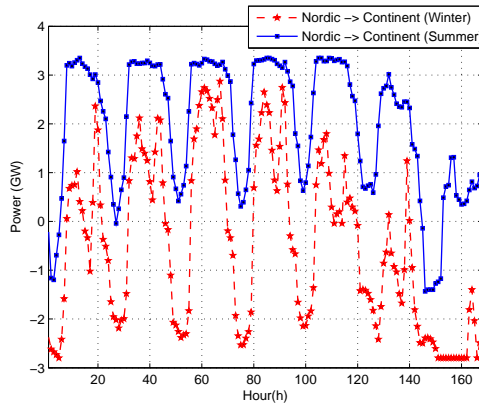


Figure 6.12: Exchange of energy between the Nordic and RG-CE power system (MW); positive values mean flow from the Nordic to RG-CE system.

the marginal cost for each block of aggregated units varying from less than 10 EUR/MWh to greater than 65 EUR/MWh. The figures illustrate that during off-peak hours, some of the peak and mid-merit units take part in generation dispatch due to the consideration of the start-up cost in the optimisation problem and reserve requirement constraint.

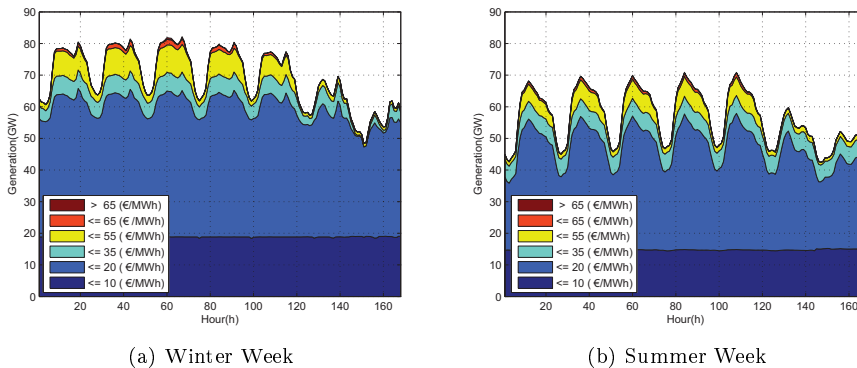


Figure 6.13: Unit dispatch in the German system

Figure 6.14a depicts the average weekly recorded prices in the northern European system in 2010 while Figure 6.14b presents the simulated price. The recorded data are downloaded from Nordpool<sup>1</sup>, APX-ENDEX<sup>2</sup>, and EEX-Germany<sup>3</sup>. The figure is similar to what has been presented in [145] representing the average weekly price structure in Germany and Norway from 2002 through 2008. Comparing Figures 6.14a and 6.14b shows that the pattern of day/night variation is representative. However, the amplitude of the variation, especially in Germany and the Netherlands, is different. A possible explanation is the model assumption of perfect markets. The mean value of actual prices of Norway, Germany, and the Netherlands are EUR 45.22, EUR 53.5, and EUR 57.24, respectively. The average simulated prices of Norway, Germany and the Netherlands are EUR 44.71, EUR 46.83, and EUR 54.35, respectively. This shows similar price behaviour as in the actual system, meaning that the prices in the Netherlands are higher than the prices in Norway and Germany, and the German prices are higher than the Norwegian prices. The comparison shows that the model reasonably captures the daily variations in prices, but with less difference between high and low prices, an effect that may be due to the perfect market assumption in the model.

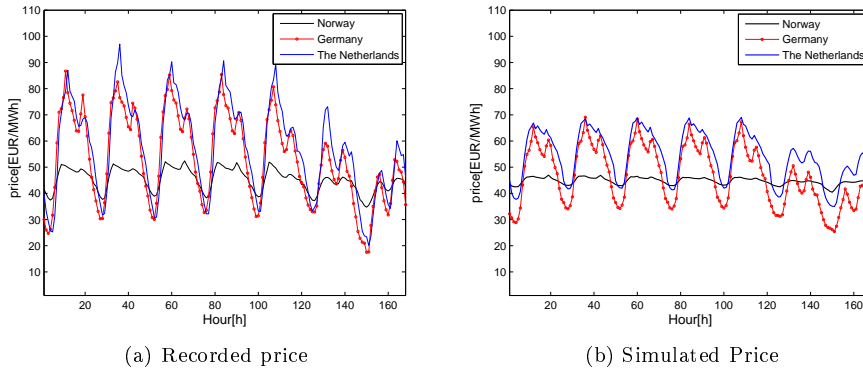


Figure 6.14: Averaged weekly spot in the northern European system, recorded prices versus simulated prices.

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<sup>1</sup><http://www.nordpoolspot.com/>

<sup>2</sup><http://www.apxindex.com/?id=36>

<sup>3</sup><http://www.eex.com/en/>



## 6.3 Paper II: Modelling of Balancing Market Integration in the Northern European Continent

*Sections 6.3.1 to 6.3.4 are mostly identical to Sections 4 to 6 in Paper II, except for minor improvement in language and notation for consistency. In order to avoid redundancy of general information, the Sections 1 to 3 in Paper II have been substituted by appropriate transitional sentences and references to previous sections. In this paper, the original model for reserve activation introduced in Paper I is applied to the case of northern European power system. However, the active power losses are neglected due to high burden of calculation unlike in Paper I. Also, the issue of reserve procurement along with day-ahead dispatch is considered in this paper. The paper documents the model description and illustrates the implementation of the model by showing the results of two selected representative hours.*

---

**ABSTRACT.** In this paper, the analysis of the integration of the regulating power markets in the northern continental Europe including the Nordic system, Germany and the Netherlands are presented. Different levels of balance market integration are analysed, varying from the current state with no integration to full integration of the regulating markets. The day-ahead dispatch and the balancing energy market are settled separately. First, the day-ahead market is modelled with simultaneous reserve procurement for the northern continental Europe. Available transmission capacity is taken into account in the reserve procurement phase. Finally, the balancing energy market is modelled as a real-time power dispatch using the day-ahead market clearing results as the basis.

Detailed results show how plant dispatch and power flows change as a result of more market integration between two synchronous systems. Cost savings are obtained due to less activation of reserves caused by imbalance netting and the use of cheaper balancing resources.

---

This paper focuses on power markets (day-ahead and balancing markets) in the northern part of Europe. In most of the European electricity markets, NTCs between bidding areas are determined by the TSOs based on security considerations and anticipations on loop flows before participants submit their bids in the day-ahead markets. Subsequently, these markets are cleared based on participants' bids/offers. Once the market is cleared and the clearing price determined, market participants self-dispatch based on their bids and offers and the market price for each hour. Their day-ahead positions are physically and economically binding, and deviations from these schedules are handled by the system operators through the balancing markets. In this respect, a two-step model the same as the model presented in Chapter 5 has been implemented. The paper documents

the model description (ref. Chapter 5, Section 5.2.1) and illustrates its usage by showing the results for two selected representative hours with different levels of integration between markets. The results are explained in the following Subsections.

### 6.3.1 Reserve procurement and system balancing

Based on today's situation in the Nordic system, each country is considered as one whole control area except Denmark, where the western part belongs to the RG-CE system. Before the reformation of balancing markets in Germany, it was divided into 4 control areas, and each was controlled by an individual TSO. The Netherlands is also one whole control area. In order to handle transmission congestion within control areas, each control area is divided into sub-areas. Figure 5.8 shows the modelled control areas and sub-areas.

The grid model includes five different synchronous systems: the Nordic system, the RG-CE system, the system of Great Britain and Ireland, and the Baltic system. The OPF data for these systems consists of 1385 nodes, 2218 branches, 12 HVDC connections, 835 generators and 109 wind farm clusters. The model has 101 generators in the Nordic system and 409 in the northern European area. Electrical parameters of transmission lines are estimated from their length and voltage levels. They are adjusted in such a way that they reflect the most significant bottlenecks in the system to a considerable extent. More details can be found in Chapter 5.

Figure 6.15 depicts the share of generation capacity that is assumed to be capable of contributing to system balancing (see Table 5.1) within the control areas. As can be seen, hydro generation has the highest share of regulating capacity, located mainly in the Nordic system. Bottlenecks in the network will not allow allocating all balancing reserve to the Nordic system, even without constraints in the amount of reserve procured outside each control area. Therefore, it is important to allocate the optimum transmission capacity to reserve exchange between control areas and control regions. Depending on the level of integration, three cases are defined for reserve procurement and real-time reserve activation:

- Case I: Represents the situation of the system before the integration of German regulating market. There is no possibility to exchange balancing services between each control area in Germany and the Netherlands, while there are exchange possibilities between the control areas in the Nordic

system. Sub-areas inside the TenneT control area in Germany are modelled to handle internal constraints.

- Case II: Represents the state of the system after integration of the four German control areas [146]. Balancing power can be exchanged between the German control areas/sub-areas and also between the areas and sub-areas within the Nordic region. However it is not possible to exchange balancing services between the Nordic system, Germany and the Netherlands.
- Case III: Represents the state of the system after full integration of balancing markets in the NE area. Reserves can be exchanged between all areas and sub-areas shown in Figure 5.7. The required reserve can be procured outside the area, provided there is enough available capacity on the transmission line from the reserve providing sub-area.

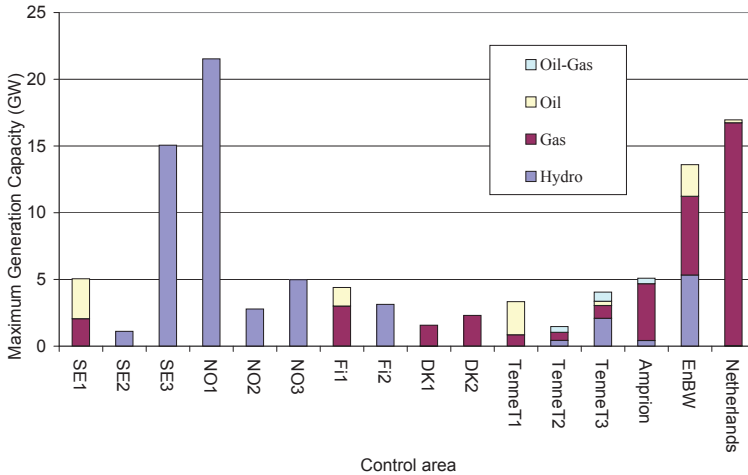


Figure 6.15: Installed regulating generation capacity in each sub-area.

### 6.3.2 Day-ahead dispatch and reserve procurement for specific hours

Reserve requirements for each control area are presented in Table 6.9. These values are based on the actual values for each area, which can be found in [7, 141, 17]. They are the requirements for secondary reserve in Germany and the Netherlands, and Fast Active Disturbance Reserve (FADR) in the Nordic system (see Section 2.4). These values are divided between the sub-areas according to their

portion of demand out of the area total annual demand.

Table 6.9: Reserve requirement for the control area and sub-areas in the NE system (MW)

Control areas	Sub-areas	Up	Down	Up	Down
Sweden	SE1			208	-208
	SE2	1220	-1220	780	-780
	SE3			232	-232
Norway	NO1			915	-915
	NO2	1200	-1200	142	-142
	NO3			143	-143
Finland	FI1			580	-580
	FI2	865	-865	285	-285
DKE	DKE	580	-580	580	-580
DKW	DKW	580	-580	580	-580
Nordic		4485	-4485		
50Hertz	50Hertz	638	-400	638	-400
TenneT	TenneT1			243	-173
	TenneT2	830	-590	281	-200
	TenneT3			306	-217
Amprion	Amprion	1003	-725	1003	-725
EnBW	EnBW	537	-330	537	-330
NL	NL	300	-300	300	-300
GE+NL		3308	-2345		

### 6.3.2.1 Procurement cost

To illustrate the effect of integration of the balancing markets, the detailed results of two specific hours in 2010 are discussed.

- Scenario 1: Hour 1171 which is an hour in the winter with 150 GW total load in the NE area.
- Scenario 2: Hour 7284 which is an hour in the late autumn with 156 GW total load in the NE area.

Table 6.10 shows the reserve procurement cost for the different cases, calculated as the difference in total dispatch cost with and without the reserve requirements.

Table 6.10: Total reserve procurement cost for the NE area [1000 EUR]

Scenario	Case I	Case II	Case III
1	96	89	78
2	130	121	112

As can be seen from Table 6.10, the cost of reserve procurement is reduced from the current state of the system to full integration of the regulating markets. For Scenario 1, the cost is reduced by EUR 7000 and EUR 9000, from case I to case II. For Scenario 2, it is reduced by EUR 11000 and EUR 9000, from Case II to Case III.

### 6.3.2.2 Procured reserve

Table 6.11 and Table 6.12 show the optimal available reserves for each sub-area in scenario 1 and scenario 2, respectively. For Scenario 1, integration of the German control areas (Case II) leads to a shift in the provision of upward regulation reserves from the 50 Hertz, TenneT1 and Amprion control areas to the TenneT1, TenneT2 and EnBW areas. It must also be noted that while there is an excess of upward regulation reserves in Case I, the procurements exactly match the requirements in Case II. With respect to the downward regulation reserves, the effect is the opposite.

Table 6.11: Available reserves, Scenario1 (MW)

Sub-areas	Case I		Case II		Case III	
	Up	Down	Up	Down	Up	Down
SE1	0	1929	0	1929	0	1929
SE2	744	372	744	372	744	372
SE3	9568	5496	9568	5496	9568	5496
NO1	9115	2414	9161	12368	9456	12073
NO2	636	2147	636	2147	636	2147
NO3	1423	3556	1423	3556	1423	3556
FI1	0	4550	0	4550	0	4550
FI2	2184	950	2184	950	2184	950
DKE	0	1311	0	1311	0	1311
DKW	0	2618	0	2764	0	2922
<b>Nordic</b>	<b>23670</b>	<b>35343</b>	<b>23716</b>	<b>35443</b>	<b>24011</b>	<b>35306</b>

Continued on next page

**Table 6.11 – continued from previous page**

Sub-areas	Case I		Case II		Case III	
	Up	Down	Up	Down	Up	Down
50Hertz	638	1896	251	1979	143	2087
TenneT1	496	1776	33	1927	376	1694
TenneT2	48	1628	191	1485	95	1581
TenneT3	462	4598	719	4221	514	4502
Amprion	1003	6425	234	6672	141	6333
EnBW	1381	9395	1580	9469	1305	9471
NL	300	4387	300	4468	8	5035
<b>GE+NL</b>	<b>4328</b>	<b>30105</b>	<b>3308</b>	<b>30221</b>	<b>2582</b>	<b>30703</b>

The amount of available upward regulation reserves in the Nordic system, and downward regulation reserves in both systems (the Nordic + German, and Dutch systems), significantly exceeds the requirement, indicating ample availability of such reserves in this hour. However, all the reserve is not necessarily available for utilisation due to transmission constraints. The total amount of procured upward regulation reserves within Germany and the Netherlands is equal to or greater than 3308 MW, the total requirement in those areas. The optimal procurement in the area NO1 (which is directly connected to Denmark and the Netherlands) also slightly changes as an indirect effect of the integration of the German areas. Changing the generation dispatch in the German areas will alter energy exchange between the control areas and consequently the power dispatch in the other areas. In Case III, the total amount of upward regulation reserves procured within Germany and the Netherlands is reduced to 2582 MW, while the remainder is provided from NO1.

For Scenario 2, the transition from Case I to Case II has a similar but stronger effect than that of Scenario 1, i.e., nearly all the upward regulation reserves are procured in the EnBW area. However, full market integration of Case III leads to a slightly increased procurement of reserves in the German areas, which now supports DKW in the Nordic system. The need for reserves in DKW was covered by imports from DKE in Cases I and II. However, in Case III, these import opportunities are quite limited due to congestion between DKE and DKW, see Section 6.3.2.3. Scenario 2 illustrates that although the normal result would be the export of reserves from the Nordic system to continental Europe, special circumstances and congestion can lead to the opposite result.

It has been assumed that there are no limitations on the share of reserves in a control area that can be procured from outside that area. Including such a constraint is straight forward, but would reduce the benefit of integration.

Table 6.12: Available reserves, Scenario 2 (MW)

Sub-areas	case I		case II		case III	
	Up	Down	Up	Down	Up	Down
SE1	0	529	0	529	0	529
SE2	124	992	124	992	124	992
SE3	4352	10712	4310	10754	4310	10754
NO1	5447	16082	5585	15944	5585	15944
NO2	1062	1721	1074	1708	1074	1708
NO3	2048	2932	2093	2886	2093	2886
FII	0	1527	0	1687	0	1700
FI2	461	2673	482	2652	499	2635
DKE	0	1110	0	1121	0	1280
DKW	227	3120	2	3337	2	3106
<b>Nordic</b>	<b>13721</b>	<b>41398</b>	<b>13670</b>	<b>41610</b>	<b>13687</b>	<b>41534</b>
50Hertz	638	2769	0	2969	0	2969
TenneT1	93	2591	0	2637	0	2691
TenneT2	371	1750	0	1979	0	1979
TenneT3	693	4886	146	5393	258	5281
Amprion	1623	7448	0	8357	0	8463
EnBW	2365	8654	3029	8335	3352	7983
NL	300	8331	300	8166	16	8341
<b>GE+NL</b>	<b>6083</b>	<b>36429</b>	<b>3475</b>	<b>37836</b>	<b>3626</b>	<b>37705</b>

### 6.3.2.3 Interconnection availability and energy flows

Table 6.13 and Table 6.14 show the availability of the corridors between sub-areas for reserve exchange in Scenario 1 and Scenario 2, respectively. As pointed out in Section 6.3.2.2, in Scenario 1 of Case III, a 1346 MW reserve is required to be procured in the Nordic system. This value includes 620 MW procured for Denmark West, and 726 MW (3308-2582), which is procured for both the German and the Dutch systems. The available HVDC capacity for upward regulating power after the day-ahead market clearing on all HVDCs except SE1-FII is  $2 \times$

Table 6.13: Day-ahead flows, Scenario 1 (MW)

	From	To	Cap.	Case I	Case II	Case III
HVDC	SE1	FII	550	550	550	550
	SE2	DKW	485	-485	-485	-485
	NO1	DKW	850	-850	-850	-850
	NO1	NL	700	-359	-404	-700
	DKE	DKW	600	-600	-600	-600
	SE1	TenneT1	600	-600	-600	-600
	DKE	50Hertz	550	-550	-550	-550
AC	DKW	TenneT1	3620	297	485	700
	TenneT1	NL	2000	742	795	933
	Amprion	NL	6923	3108	3055	2870

$(485+850+700+600+600+550) = 7570$  MW (grey cells in Table 6.13) which covers the required interconnection transmission availability. Furthermore, there is sufficient available capacity on the AC interconnections between Denmark West-TenneT1 and TenneT1-the Netherlands for the balancing services exchange.

In Scenario 2 of Case III, the available reserve capacity for upward regulating reserve on the HVDC interconnections to the other synchronous areas, including Denmark West, is equal to  $(600-512) + (550-338) = 300$  MW (grey cells in Table 6.14). The procured reserve in Denmark West is 2 MW. Therefore, the total procured reserve from the Nordic system is equal to 302 MW. Moreover, it is needed to procure  $620-302 = 318$  MW of upward regulating reserve for Denmark West from Germany and the Netherlands to satisfy the reserve requirement in the Nordic system. Thus, the total procured reserve in the German areas and the Dutch system is equal to  $3306+318 = 3626$  MW.

### 6.3.3 Real-time balancing in NE area for specific hours

The model for real-time balancing is implemented as an incremental power flow where the inputs are the results of generation dispatch after the day-ahead market clearing and system imbalances. The model's imbalances are represented by recorded imbalance scenarios for Germany and the Netherlands, as well as the Nordic system. A common Program Time Unit (PTU) of 15 minutes is used corresponding to the present practice in Germany and the Netherlands. Table 6.15 shows the real-time imbalances for both Scenarios 1 and 2.



Table 6.14: Day-ahead flows, Scenario 2 (MW)

	From	To	Cap.	Case I	Case II	Case III
HVDC	SE1	FII	550	534	5454	454
	SE2	DKW	485	485	485	485
	NO1	DKW	850	850	850	850
	NO1	NL	700	700	700	700
	DKE	DKW	600	-20	-18	512
	SE1	TenneT1	600	600	600	600
	DKE	50Hertz	550	550	550	338
AC	DKW	TenneT1	3620	2580	2568	2770
	TenneT1	NL	2000	412	396	428
	Amprion	NL	6923	3438	3454	3422

Table 6.15: Real-time imbalances for both scenarios (MW)

Control areas	Scenario 1	Scenario 2
Sweden	12	122
NO1	-90	218
NO2	0	0
NO3	0	0
Finland	0	0
DKE	-20	-506
DKW	0	-327
Nordic	-98	-493
50 Hertz	327	-304
TenneT	149	290
Amprion	0	41
EnBW	-50	62
NL	61	-16
GE + NL	487	72

To model the cost of balancing in accordance with the actual behaviour of the balancing markets, a similar assumption as in [99] is made, increasing the costs of the hydro plants by 10 % for upward regulation and decreasing them by 10 % for downward regulation. For thermal plants, there is a corresponding 40 % increase/decrease.

### 6.3.3.1 Balancing production cost

Table 6.16 represents the NE area balancing cost for the first PTU in both scenarios.

Table 6.16: Total reserve procurement cost for the NE area [1000 EUR]

Scenario	Case I	Case II	Case III
1	35.40	32.95	22.97
2	27.30	24.80	1.87

The balancing cost is reduced by EUR 2450 and EUR 2500 from case I to II, and by EUR 9980 and EUR 22930 from case II to III, in scenarios 1 and 2, respectively. The significant reduction in Case III is caused by the cancelling out of positive and negative imbalances (“imbalance netting”) in the respective systems as illustrated below.

### 6.3.3.2 Activated reserve

Table 6.17 shows the activated regulating reserve in each scenario for the respective cases. In Cases I and II of Scenario 1, the activated volume is equal to the deviation within each area except for the Nordic system where there is a common market for balancing. This is also the case for Germany in Case II. In Case III, most of the reserve activation is moved to the Nordic system. Given the opposite direction of system imbalances in the Nordic and other systems, imbalance netting has occurred, implying a flow of 278 MW from the Nordic system to the German and Dutch systems. The high amount of this activated reserve is procured by the cheap Norwegian hydro generators located in the NO1 sub-area. In Cases I and II of Scenario 2, the net activated reserve is -493 MW in the Nordic system and 72 MW for the German and Dutch systems. In Case III, the activated reserve is -280 MW and -140 MW for the Nordic system, and the German and Dutch systems, respectively. Again, there is a strong netting effect in the German and Dutch systems, and a net export from the Nordic system to these systems.

Table 6.17: Activated reserves in each sub-area (MW)

Sub-areas	Scenario 1			Scenario 2		
	Case I	Case II	Case III	Case I	Case II	Case III
SE1	0	0	0	0	0	0
SE2	0	0	39	-113	-110	-69
SE3	0	0	32	0	0	0
NO1	-78	-78	109	-378	-380	-193
NO2	0	0	0	-2	-2	-18
NO3	0	0	0	0	0	0
FII	0	0	0	0	0	0
FI2	0	0	0	0	0	0
DKE	-20	-20	0	0	0	0
DKW	0	0	0	0	0	0
<b>Nordic</b>	<b>-98</b>	<b>-98</b>	<b>180</b>	<b>-493</b>	<b>-493</b>	<b>-280</b>
50Hertz	327	327	34	-304	-304	-169
TenneT1	149	77	175	51	114	0
TenneT2	0	22	0	14	0	0
TenneT3	0	0	0	225	146	29
Amprion	0	0	0	41	106	0
EnBW	-50	0	0	62	26	0
NL	61	61	0	-16	-16	0
<b>GE+NL</b>	<b>487</b>	<b>487</b>	<b>209</b>	<b>72</b>	<b>72</b>	<b>-140</b>

### 6.3.3.3 Cross-border balancing energy exchange

The balancing power exchange in Scenarios 1 and 2 is shown in Table 6.18 and Table 6.19, respectively. The results of Scenario 1, Case III shows that the exchange energy on interconnections between the Nordic system and the German and Dutch systems is increased by 278 MW, compared to the day-ahead case, showing the export of upward regulating power from the Nordic to the German and Dutch systems. In the second scenario, the exchange is increased by 212 MW, showing the import of upward regulating power from the Nordic system.

Table 6.18: Balancing exchange Scenario 1 (MW)

	From	To	Case I	Case II	Case III
HVDC	SE1	FI1	0	0	0
	SE2	DKW	0	0	0
	NO1	DKW	0	0	0
	NO1	NL	0	0	186
	DKE	DKW	0	0	20
	SE1	TenneT1	0	0	72
	DKE	50Hertz	0	0	0
AC	DKW	TenneT1	0	0	20
	TenneT1	NL	22	4	-62
	Amprion	NL	-22	-4	-63

Table 6.19: Balancing exchange Scenario 2 (MW)

	From	To	Case I	Case II	Case III
HVDC	SE1	FI1	16	25	42
	SE2	DKW	-397	-396	-153
	NO1	DKW	-415	-416	-262
	NO1	NL	0	0	0
	DKE	DKW	485	485	88
	SE1	TenneT1	0	0	0
	DKE	50Hertz	0	0	212
AC	DKW	TenneT1	0	0	0
	TenneT1	NL	-1	7	-7
	Amprion	NL	1	-7	-9

### 6.3.4 Discussion

In the existing market structure in the northern European area, the regulating reserves are procured and activated inside each control area, except for the Nordic system and Germany, where the cheapest regulating reserves are selected from the common merit order lists. In these analyses, it is illustrated, by way of the detailed description of two specific cases, how the implementation of cross-border balancing markets influences the procurement and dispatch of balancing services,

and how this changes the cross-border flows. Also, cost savings for these particular hours are reported.

The cross-border procurement of reserves takes into account transmission constraints through a simultaneous market clearing and reserve procurement. Although this is not in accordance with current practice, it could be realized by letting generators submit simultaneous bids for energy and balancing. In any case the analysis shows the effect of cross-border procurement of reserves.

Three additional issues must be discussed in this context. First, according to current practice, it is not acceptable to procure the whole required reserve from outside of the control area. The model can easily be modified to the ENTSO-E policies, where at most one-third of the required secondary reserve is allowed to be procured from outside of the area [4]. However, increasingly integrated markets may relax this requirement over time. Next, with today's manual reserve dispatch in the Nordic system, it would not be possible to change the set point of a different number of generators at the same time. The proposed solution would require the use of Automatic Generation Control (AGC). This is presently being considered by the Nordic TSOs. Finally, it may be necessary to include ramp rates to increase the realism of the analysis. This implementation is relatively straight forward by adding relevant constraints in the mathematical framework.

## 6.4 Paper III: Balancing Market Integration in the Northern European Continent

*This section is mainly identical to Sections III and IV in the paper, but some of the introductory text from Section III has been left out and minor improvements in language have been made. The first two sections in the paper describe the background, context and literature, which is superfluous in the context of this thesis and the model, which has already been described in Chapter 5. In this paper, the methodology introduced in Paper II is implemented in the long-term analysis of multi-national balancing market ranging from weekly to annual analysis.*

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ABSTRACT. This paper analyses the integration of the balancing power markets in northern Europe including the Nordic system, Germany and the Netherlands. Two cases of balancing market integration are analysed: the current state with individual balancing markets, and the full integration of these markets, where the

day-ahead market and the balancing market are settled separately. First, the day-ahead market is modelled as a common market for the whole European continent, while a simultaneous reserve procurement modelling is done for northern Europe. Available transmission capacity is considered to be allocated implicitly for the exchange of balancing services based on a trade-off between day-ahead energy and balancing capacity exchange. Next, the balancing energy market is modelled as a real-time power dispatch on the basis of the day-ahead market clearing results and the simulated imbalances.

Detailed results for two different weeks in winter and summer are presented. They illustrate the consequences of market integration between two synchronous areas on procured and activated reserve, generation dispatch and power flows. It is demonstrated that cost savings can be achieved due to the use of cheaper balancing resources and less activation of reserves caused by imbalance netting. Such savings are estimated for a whole year of operation, and amount to approximately EUR 400 million per year.

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Market integration influences the operating cost both in the day-ahead and the real-time markets, as well as the exchange energy, and the procured and the activated balancing services between balancing areas. Integration also has an implicit impact on the operating cost in the day-ahead market through the procurement of reserves in the balancing area, where cheaper resources are situated. In the real-time market, the integration of larger geographical areas leads to cost savings by the so-called imbalance netting and the availability of cheaper balancing resources.

In order to study the effect of balancing market integration on the reserve procurement and activation within the northern European area, two cases have been studied (the same case studies presented in Section 5.3).

- Case I: It is the reference case and represents the current state of the system. In this case, there is no possibility of exchanging balancing services between the Nordic and the continental balancing areas. Balancing services can be exchanged between the balancing areas within the Nordic system and within Germany.
- Case II: It represents full integration of the balancing markets in Northern Europe where regulating reserves can be exchanged system-wide.

To handle congestion within each country, the countries are divided into areas. Figure 6.16 shows the modelled balancing areas and the HVDC connections between the Nordic and the RG-CE systems. NTC values between the countries,

## 6.4. Balancing Market Integration in the Northern European Continent

as given by ENTSO-E<sup>4</sup>, are used as constraints in the power flow optimization.

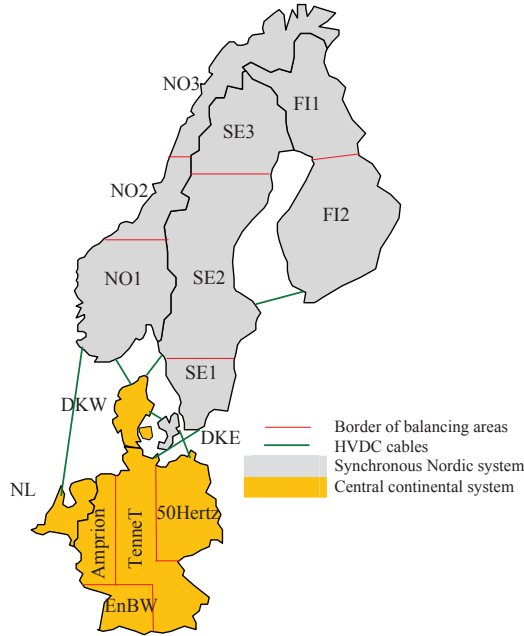


Figure 6.16: The northern continental European model

The same model as in Section 6.3 is employed in this paper. In order to illustrate the results in some detail, available reserves are presented for two typical weeks in winter (week 6) and summer (week 28) in 2010. Figure 6.17a shows the available reserves in the German system. In some (low load) hours, available upward reserves (see Table 6.20) exceed the requirement, where the simulated procurement price will be zero. However, in most hours the requirement for upward reserves is an active constraint, resulting in positive prices. Normally, there are ample downward reserves in the German system, with the exception of some low load hours during the summer week. In the Norwegian system (Figure 6.17b), there are ample reserves for upward regulation, but the amount of downward regulation reserves is limited during low load hours.

<sup>4</sup>European network of transmission system operators for electricity, <https://www.entsoe.eu/>

Table 6.20: Required reserve in the NE area (MW)

Balancing area	Upward regulation	Downward regulation
Sweden	1220	-1220
Norway	1200	-1200
Finland	865	-865
Denmark (East + West)	1200 (580+620)	-1200 (-580-620)
Nordic	<i>4485</i>	<i>-4485</i>
Germany	3008	-2045
The Netherlands	300	-300
RG-CE	<i>3308</i>	<i>-2345</i>

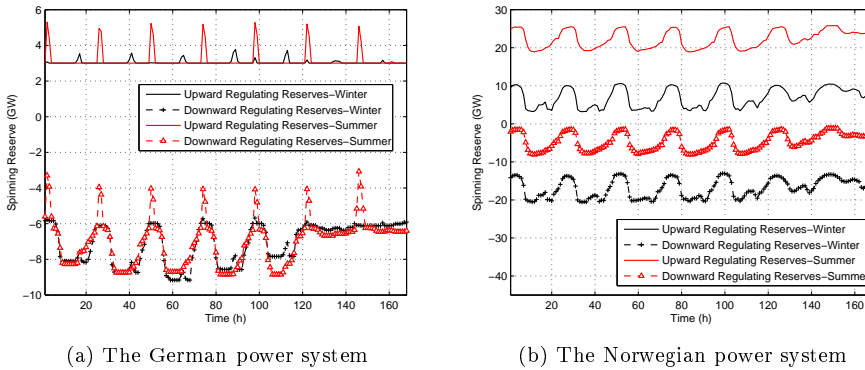


Figure 6.17: Available reserve (GW)

#### 6.4.1 Reserve procurement under different balancing market integration cases

The procured regulating reserve includes both upward and downward reserves. Under full integration (Case II), it is possible to exchange balancing services between the Nordic system, Germany and the Netherlands. In the continental system, the operation policies of ENTSO-E [4] are taken into account, which



means that at most one-third of the required reserve should be procured outside the balancing area.

Reserves are procured simultaneously with the day-ahead dispatch for each 24-hour simulation period. To ensure the availability of sufficient reserves in practical market implementations in Europe, secondary and tertiary reserves are procured for longer time intervals. The periods vary, from day-ahead for tertiary reserves in Germany, to annual procurement for secondary reserves in the Netherlands, and periods in between these extremes for other countries [20], [91], [29] (for more details see Chapter 3). Longer tendering periods lead to more uncertainty and less flexibility, and therefore higher costs for reserve procurement. However, longer tendering periods may often be desired by the TSOs for system security provided all the parties involved agree upon available volume well in advance, which mitigates uncertainty. The model represents a market solution with a daily reservation, which results in lower procurement costs [147] than those in the existing markets.

The summary results of the two cases for the two selected winter and summer weeks are presented in Table 6.21. The integration of balancing markets leads to the import of an average of 1020 MW of upward regulating reserve (31% of the requirement) from the Nordic system to the continental countries in the winter week. This import decreases to 626 MW (19% of the requirement) in the summer week, mainly because the available transmission capacity is mostly used for day-ahead energy exchange. There is no significant procurement of downward regulating reserve between the systems. The operational saving is captured as the weekly operation cost difference between the cases. The cost of reserve procurement is reduced from EUR 3.6 million in Case I to EUR 0.75 million in Case II for the winter week. It reduces from EUR 2.15 million in Case I to EUR 0.32 million in Case II for the summer week, reducing the reserve procurement cost by EUR 2.85 million and EUR 1.83 million for the winter and the summer weeks, respectively.

Table 6.21: The result of balancing market integration on reserve procurement (Up → upward regulation, Down → downward regulation)

Result	Winter (week 6)				Summer (week 28)			
	Case I		Case II		Case I		Case II	
	Up	Down	Up	Down	Up	Down	Up	Down
Total procured reserve In the Nordic system (MW)	4485	-4485	5505	-4496	4485	-4485	5111	-4494
Total procured reserve In the RG-CE system (MW)	3308	-2345	2288	-2334	3308	-2345	2682	-2336
Average balancing services exchange (MW/h)	0	0	1020	11	0	0	626	9
Procurement cost (million EUR)	3.6		0.75		2.15		0.32	

Table 6.22 summarizes the average procured reserves per country for the winter and the summer weeks. In Case I, the procured upward and downward reserves in Norway and Sweden exceed the requirements, showing that these countries export regulating reserve within the Nordic system. Finland imports upward regulating reserve, especially during the summer. Denmark imports both upward and downward reserves from Norway and Sweden in both weeks. A comparison of Case I with Case II shows that full market integration leads to a shift in the provision of upward regulating reserve from the RG-CE system to the Nordic system, as demonstrated by the increase in the procured reserves in Norway and Sweden from Case I to Case II. In the summer week, there is also an export of upward regulating reserve from the Netherlands to Germany. This is because the requirements in the Netherlands are low compared to the available reserve, and because the import capacities on the corridors between the RG-CE and the Nordic systems have been used in the day-ahead generation dispatch.

Table 6.22: Average weekly per country procured reserve in the winter and the summer weeks (MW)

Balancing area	Winter week						Summer week			
	Case I		Case II		Case I		Case I		Case II	
	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down
Sweden	1221	-1813	1279	-1240	2009	-1595	2152	-1201		
Norway	2359	-1557	3326	-2166	2269	-1854	2776	-2256		
Finland	864	-863	863	-846	76	-865	77	-865		
Denmark	41	-252	37	-244	131	-171	106	-172		
Nordic	4485	-4485	5505	-4496	4485	-4485	5111	-4494		
Germany	3008	-2045	2034	-2079	3008	-2045	2111	-2045		
The Netherlands	300	-300	254	-255	300	-300	571	-291		
RG-CE	3308	-2345	2288	-2334	3308	-2345	2682	-2336		

The transmission corridor between Denmark and Norway consists of 3 parallel HVDC cables called Skagerrak connecting the South of Norway to western Denmark, with a capacity of 940 MW. The transmission corridors between Sweden and Denmark consist of both AC and HVDC cables. The HVDC link called Kontiskan connects southern Sweden with western Denmark, with a capacity of 550 MW. The AC cross-border connections include four main corridors with different voltage levels linking southern Sweden to eastern Denmark. The internal constraints of the Danish power system limit the capacity of this link, and therefore the NTC of the link is equal to 1350 MW from Sweden, and 1750 MW to Sweden. The total transmission capacity between Denmark and its neighbouring countries in the Nordic system is 2840 MW to Denmark, and 3240 MW from Denmark [23].

Figure 6.18 shows the effect of balancing market integration on day-ahead cross-border flows between Denmark, and both Norway and Sweden. Dashed lines above and below in Figure 6.18 show the transmission capacity for both directions. The remaining capacity (difference between the corridor's capacity and the day-ahead flows) is allocated to the exchange of balancing services. This allocation represents an optimum trade-off between day-ahead and cross-border reserve procurement for the usage of interconnection capacity. The energy exchange in Case II in both the weeks is higher than in Case I since the fully integrated market makes it possible for the Danish system to procure the required reserve through the link to northern Germany. Therefore, the Danish system imports more power during the peak load hours and exports during off-peak hours in the day-ahead market.

### 6.4.2 Real-time market integration

The same model as in Section 5.3 is used for real-time dispatch. The model's imbalances include deviations in both the load and the wind production, based on recorded imbalance scenarios in 2008 [27, 141, 17].

The results of real-time market integration are presented in Table 6.23. The activated reserves are lower in Case I than in Case II, showing the benefit of imbalance netting in a larger geographical area. In Case II, on an average, 318 MW and 114 MW of upward reserve per hour are exported from the Nordic system to the continental system in real-time for the winter and the summer weeks, respectively. The corresponding export of downward reserve is 43 MW and 54 MW, respectively. With the implementation of system-wide reserve activation, the system balancing cost is reduced from EUR 7.74 million in Case I to EUR 3.74 million in Case II for the winter week, and from EUR 5.4 million in Case I

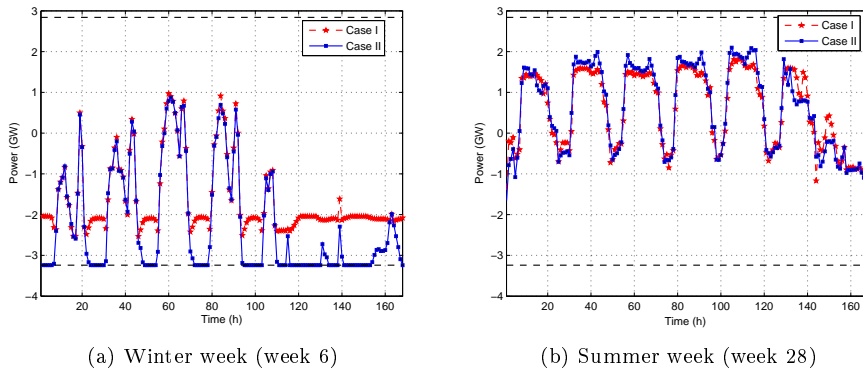


Figure 6.18: Cross-border flow between Denmark and both Norway and Sweden (GW) in the winter and summer weeks. Positive values indicate flow from Norway and Sweden to Denmark.

to EUR 2.9 million in Case II for the summer week.

Table 6.23: The result of real-time balancing market integration

Result	Winter week				Summer week			
	Case I		Case II		Case I		Case II	
	Up	Down	Up	Down	Up	Down	Up	Down
Imbalances (GWh)	65.8	-67.74	65.8	-67.74	52.16	-86.12	52.16	-86.12
Activated balancing reserve (GW)	64.52	-66.76	45.38	-47.62	51.63	-83.79	31.55	-63.70
Average activated balancing services ex-change (MW/h)	0	0	318	43	0	0	114	54
Balancing cost (million EUR)	7.74		3.74		5.4		2.9	

Figure 6.19 presents the real-time deviations in the selected winter and summer weeks. As can be seen in some hours, e.g., hour 58 in the winter week and hour 12 in the summer week, the imbalances in the Nordic and German systems are in the opposite direction, illustrating the benefits of imbalance netting.

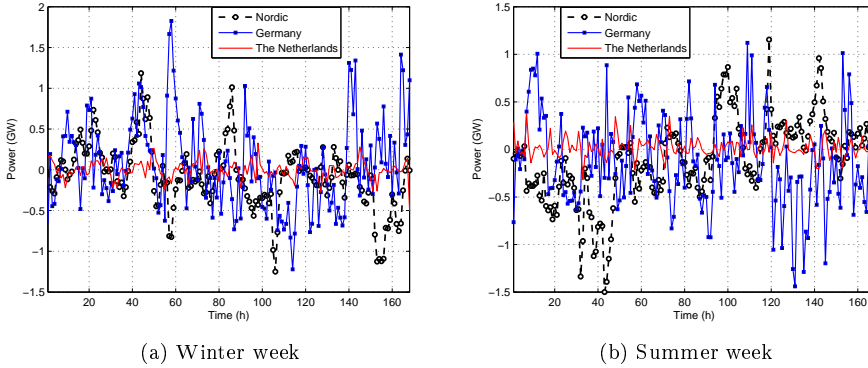


Figure 6.19: Real-time imbalances in the winter and the summer weeks (GW)

Figure 6.20 illustrates the activation of reserve for Case II. Most of the upward activation has been moved to the Nordic system while downward regulation is handled by the German system. A sample effect of imbalance netting can be seen in hour 58 for the winter week and hour 12 for the summer week.



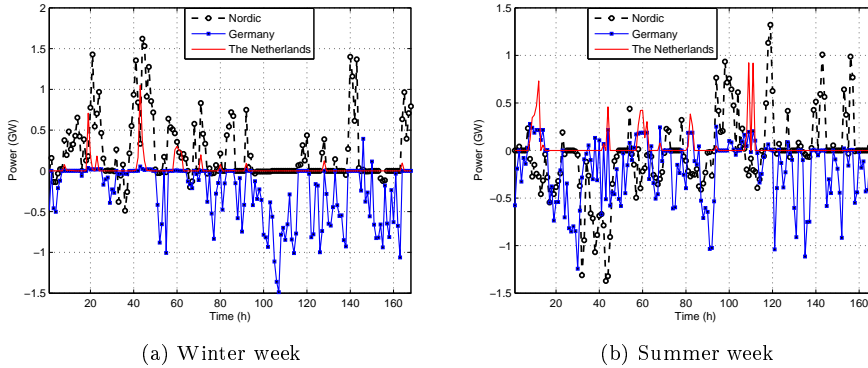


Figure 6.20: Activation of reserve after full market integration (GW)

### 6.4.3 Annual results

In the preceding section, the results for two specific weeks in the year 2010 illustrated the detailed description of the model behaviour. In this section, the annual results are described. Table 6.24 shows the average procured upward and downward reserves in each country. With system-wide reserve procurement, an average 0.9 GW of upward regulating reserve in the RG-CE system is procured in the Nordic system, representing approximately 30% of the required reserve in that system. Table 6.25 compares the average activated reserve in Case I with that in Case II. In Case II, the upward regulating activation in the Nordic system has increased by 34%, whereas the downward regulating activation has decreased by 84%, compared to Case I. The upward regulating activation in the RG-CE system has decreased by 84%, and downward regulating activation reserve has increased by 14% of the activated reserve, compared to Case I. Overall, both the upward and downward activation reserves have been decreased by 31% through the effect of imbalance netting. It turns out that approximately 50% of upward regulating reserves in the RG-CE system have been activated from the Nordic system, while the same percentage of downward activated reserves has been activated from the RG-CE system.

Figure 6.21 shows the annual aggregated exchange of regulating reserve between the Nordic and the RG-CE systems. The difference between the day-ahead and the real-time transmission exchanges are equal to the exchange of balancing energy. The exchange varies between -1 and +2.5 GW during the year. The gross

Table 6.24: Averaged annual procured reserves in case I and case II (MW)

Balancing area	Case I		Case II	
	Up	Down	Up	Down
Sweden	1353	-1964	1428	-1332
Norway	2310	-1700	3156	-2297
Finland	734	-652	737	-635
Denmark	88	-169	68	-177
Nordic	<i>4485</i>	<i>-4485</i>	<i>5389</i>	<i>-4441</i>
Germany	3008	-2045	2075	-2119
The Netherlands	300	-300	329	-270
RG-CE	<i>3308</i>	<i>-2345</i>	<i>2404</i>	<i>-2389</i>

Table 6.25: Averaged annual activated reserves in each country (MW)

Balancing area	Case I		Case II	
	Up	Down	Up	Down
Sweden	36	-19	72	-2
Norway	169	-185	195	-33
Finland	7	-5	13	0
Denmark	2	-12	2	0
Nordic	<i>214</i>	<i>-221</i>	<i>282</i>	<i>-35</i>
Germany	207	-219	10	-297
The Netherlands	46	-38	30	-1
RG-CE	<i>253</i>	<i>-257</i>	<i>40</i>	<i>-298</i>
Total	<b>467</b>	<b>-478</b>	<b>322</b>	<b>-333</b>

exchange is 3.2 TWh, and the net exchange is 2.2 TWh from the Nordic to the RG-CE systems.

The annual cost of reserve procurement is reduced from EUR 195 million in Case I to EUR 42 million in Case II, a reduction of EUR 153 million or 75% of the total reserve procurement cost. The annual balancing cost is reduced from EUR 393 million in case I to EUR 189 million in Case II, representing an operational saving of EUR 204 million for real-time dispatch. The total annual saving is EUR 399 million for both procurement and activation of reserves.

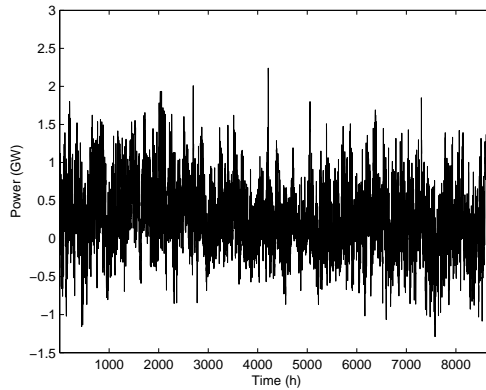


Figure 6.21: Annual activated regulating resources exchange between the Nordic system and the RG-CE areas (GW). Positive values indicate flow from the Nordic system to the RG-CE system.

### 6.4.4 Discussion

In this paper, the required reserve for the northern European system is procured simultaneously with the day-ahead market clearing for the whole continent. The reserve procurement takes the transmission constraints into account. The results indicate that normally ample reserves are available in the Nordic system. This is due to the fact that hydro power plants make up such a large part of the Nordic production portfolio, and that hydropower plants have favourable properties as a regulating resource.

Two cases for balancing market integration have been analysed: the reference Case I, representing the current situation without the integration of the Nordic and the continental balancing markets; and Case II, representing the full integration of these markets.

The analysis shows in detail how the dispatch of generating units and the exchange between areas vary for different levels of balancing market integration. This illustrates the profitability of the exchange of reserves between the synchronous systems using the existing HVDC interconnections.

## 6.5 Paper IV: Balancing Market Integration in the Northern European Continent: A 2030 Case Study

*Section 6.5 is a copy of Sections II, III, VI, and VII of paper VI. Sections IV and V of the paper have been significantly shortened because the relevant concepts have already been explained in other parts of this thesis.*

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ABSTRACT. More production flexibility is needed in the future operation of power systems where more uncertainty is introduced due to the growing wind power penetration. In this paper, a comparison is carried out between two balancing market models, simulating non integrated and fully integrated northern European markets using a 2030 scenario. Wind power is modelled based on high resolution numerical weather prediction models and wind speed measurement for actual and forecasted wind power production. The day-ahead dispatch and the balancing energy market are settled separately. The same model as in Section 6.4 is employed in this study. The results show the benefit of balancing market integration for handling the intermittent production. Cost savings are obtained due to less activation of reserves caused by imbalance netting and the smoothing effect of wind power production, as well as the availability of cheaper balancing resources when integrating larger geographical areas.

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### 6.5.1 System description

The objective of the paper is to bring forward the quantitative analysis of the integration profitability in the future power system scenario in light of increased wind power production penetration.

The production is modified based on the future scenarios of production mixture presented in IEE-EU TradeWind project [148]. The annual total power generation in the Nordic system is expected to be 445 TWh in 2030 [148], whereof 16% is produced by wind power. Wind scenarios corresponding to these figures will be discussed in Section 6.5.3. Norway is expected to produce 88% of its power from hydro energy while the remaining 12% will be produced by wind power generation. Sweden and Finland have a mix of hydro power, nuclear power and other conventional thermal power generation. In both countries, the hydro power stations are mostly located in the northern areas whereas the southern areas are dominated by thermal power stations. The share of wind power production in Sweden and Finland is estimated to be 15% and 7%, respectively. Denmark is expected to have a high contribution from wind power (44% of the total annual

production), whereas the remainder of the power supply is mostly covered by conventional thermal power plants.

The power production in the Netherlands is based on a mix of hard coal, natural gas-fired and oil-fired power plants, with a substantial share of Combined Heat and Power (CHP) plants. Wind power production in 2030 is expected to be 19.5% of the total estimated power production of 139 TWh [105]. The annual production in Germany is estimated to be 540 TWh. A substantial share is provided by lignite coal and the other types of production including a mix of natural gas, hard coal and hydro. All the nuclear power plants are assumed to be shut down by 2030 [149]. The wind power contribution is estimated to be about 32% of the total annual production. The assumed generation mix for the rest of the countries of European power system are taken from the 2030 medium scenario of the IEE-EU TradeWind project [148]. Furthermore, the scenarios for installed onshore and offshore wind power are described in Section 6.5.3. The estimated annual load for each country is based on the “combined high renewable and efficiency” load demand scenario developed by European Wind Energy Association (EWEA) [105].

Table 6.26 represents the total installed generation in the northern European countries in 2010 and 2030. Figure 6.22 compares the existing installed types of generation capacity in 2010 to the projected capacity in 2030 [116]. As shown, the nuclear power plants in Germany are expected to be shut down completely, and a substantial increase in wind power production would be observed in all countries. In the Netherlands and Sweden, the high share of gas-fired and nuclear power plants are expected to be substituted by wind power and other renewable production, respectively. In Norway and Finland, the penetration of wind power production is expected to increase considerably. Wind power production is expected to take over a significant portion of the share of hard coal power production in Denmark.

Table 6.26: Installed generation capacity (GW) in 2010 and 2030

Year	Norway	Sweden	Denmark	Finland	Germany	the Netherlands
2010	30.44	34.24	10.34	15.77	144.00	25.53
2030	39.81	39.11	15.70	21.75	169.81	34.54

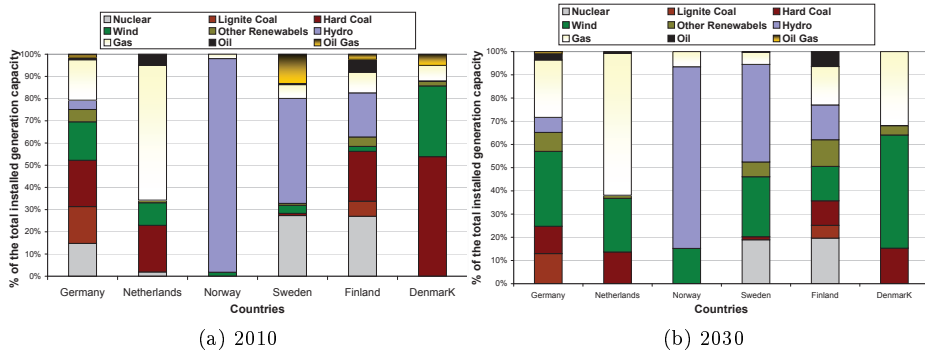


Figure 6.22: Share of installed generation capacity in 2010 and projected capacity in 2030(GW)

### 6.5.2 North Sea Offshore Grid

A stronger connection to the Nordic hydro power can also be realised by an offshore grid. The main driver for establishing an offshore super-grid is the possibility to transmit offshore wind power to the load centres onshore. An offshore grid allows for an increased wind penetration and therefore a reduction of operational costs. This contributes towards reaching the 20-20-20 targets and beyond, as well as an increase in the security of supply [150]. An offshore grid is also an important step forwards in an integrated electricity market. A recent detailed techno-economic analysis has shown that an offshore grid can be highly beneficial from an economic perspective as well [150].

Figure 6.23 shows the offshore grid design used in the model, corresponding to the EWEA 20 year offshore network development master plan (North and Baltic Seas) [10]. The grid topology shown in Figure 6.23 links the North Sea neighbouring countries, namely the UK, Norway, Denmark, Germany, the Netherlands, Belgium and the north of France. This grid development strategy allows the cross-linking of offshore wind farms while improving the interconnection between the Nordic area and northern Europe.

For onshore grid the same model as described in Section 5.1.2.2 is elaborated together with the grid upgrades presented in Table 20 in [116]

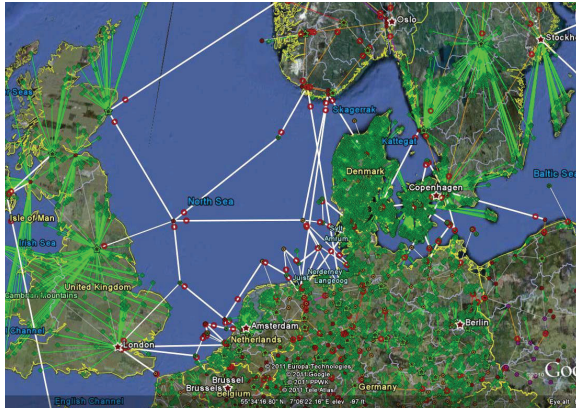


Figure 6.23: Offshore grid configuration in 2030 recommended by EWEA [10]

### 6.5.3 Wind power production modelling

In this section, the model for wind power production and wind forecast error are presented.

#### 6.5.3.1 Wind power data

The simulated wind power production is based on a mixed wind speed model that is a combination of a numerical prediction model and wind speed measurements. The wind speed measurements are provided from more than 200 gauging stations. The numerical prediction model, COSMO EU [151], provides simulated wind speed data for offshore wind location. The COSMO EU model is developed by the Consortium for Small-scale Modelling<sup>5</sup>. The model is designed for both numerical weather prediction and various scientific applications. It covers the whole of continental Europe, the eastern Atlantic and northern Africa. The mixed wind speed model offers the possibility to simulate both onshore and offshore wind scenarios with high time resolution and high spatial resolution. More details of wind speed-power curve, wind power time series and associated forecast errors employed in this work are given in [152].

Table 6.27 presents the scenarios used for 2010 and 2030. The wind to power conversion is based on wind speeds from 2010. To match the installed capacity of the future scenarios, each wind farm has been scaled up to meet the 2030 values.

<sup>5</sup><http://www.cosmo-model.org/>

Table 6.27: Installed wind power generation capacity (GW) 2010 and 2030

Areas	2010			2030		
	Onshore	Offshore	Total	Onshore	Offshore	Total
Norway	0.55	0	0.55	3.95	2.1	6.05
Sweden	0.94	0.31	1.25	4.24	5.86	10.1
Denmark	2.67	0.62	3.29	4.5	3.15	7.65
Finland	0.13	0.22	0.35	1.07	2.15	3.22
Germany	24.01	0.93	24.94	29.55	25.26	54.81
Netherlands	2.3	0.3	2.6	3.55	4.43	7.98
sum	30.6	2.38	32.98	46.86	42.95	89.81

The scenarios for 2030 are collected from the IEE-EU TradeWind project [148]. The power output of each of the 3200 wind farms is modelled individually, in order to reduce scaling errors. The installed capacity is scaled up to meet the assumed installed capacity in 2030. Planned and commissioned offshore facilities are included in the data set. Consequently, surface, roughness, length, topography and turbine characteristics for each onshore and offshore wind power production as well as future wind power production curves are included in the simulation. Each wind farm is connected to the nearest bus in the grid model.

Figure 6.24 shows the grid model and aggregated onshore and offshore wind power productions in Western Denmark. The green lines represent each individual wind farm connected to the nearest bus, and the white lines correspond to HVDC cables. The wind production forecast is provided for 3-hours (3-h) and 24-hours (24-h) ahead, which is solely based on COSMO EU's wind speed data. More details of the model are presented in [152].

### 6.5.3.2 Wind forecast errors

Reducing wind power forecast errors will reduce the imbalances of wind power producers, and can be achieved by allowing bids closer to delivery. For instance, Figure 6.25 shows the wind power forecast error for 24-h and 3-h ahead for the aggregated wind farms situated within the NE system. A significant increase in the accuracy of wind power production is noticeable for the 3-h compared to the 24-h forecast. The mean absolute forecast error for the 24-h forecast in this case equals to 16353 MW (18 % of installed wind power), whereas it reduces to 855



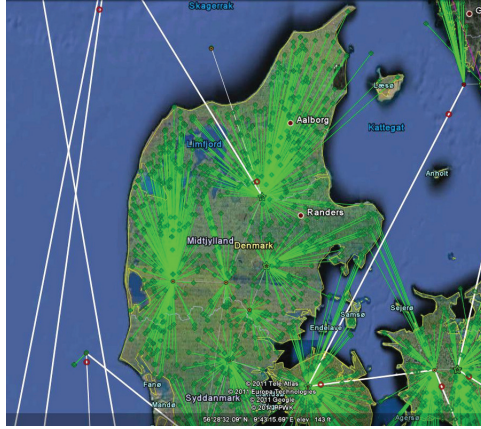


Figure 6.24: Wind power production in the western Denmark

MW (less than 1 % of the installed wind power) for the 3-h forecast. However, using mean absolute forecast error provides a rather optimistic picture of the balancing services requirement. There are considerably higher wind forecast errors, especially before and after storm fronts. The largest deviation in the 2030 wind scenario forecast for 24-h ahead is estimated to reach an absolute value of about 65 GW, whereas this deviation reduces to 6.2 GW for the 3-hour forecast as shown in Figure 6.25. Therefore, provision of capacity and real-time balancing energy activation for 24-h wind power forecast error could result in unnecessary high balancing costs.

Trading part of the imbalances in the intra-day market, closer to the hour of delivery will help reduce the forecast errors of wind power. Gate closure times in present intra-day markets are typically around one hour before the hour of operation. On this basis, it could be argued that a 1-h forecast error would be the appropriate basis for reserve procurement. However, this would underestimate the need for reserves. Firstly, there is no guarantee that the intra-day markets would result in a balance 1 hour before operation - there are no obligations in these markets, the economic risk of not being in balance is the driving force. Secondly, even if intra-day markets would result in a balance between demand and supply 1-h before operation, this would still require reserve resources from market participants. Even if this is not a cost for the TSO, it is a cost for the market. Because this analysis takes a socio-economic approach, it is necessary to include also these costs. Therefore, the 3-h wind power forecast error is used as the basis to estimate the reserve levels in this study. But this is certainly an

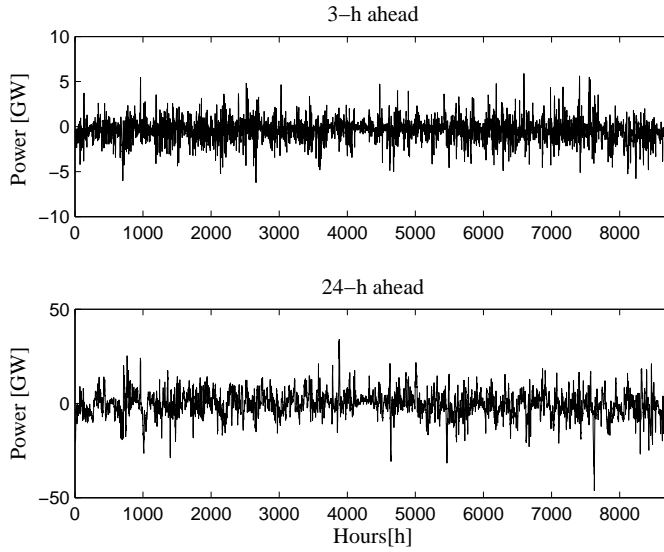


Figure 6.25: Wind power forecast error in 2030 for 3-hour and 24-hour ahead (GW)

issue where more research is needed.

Figure 6.26 compares the distribution of wind forecast errors to a normal distribution. The plot includes a reference line for judging whether the data follows a normal distribution. As can be seen, the forecast errors follow a normal distribution between the probability of 0.05 to 0.95, showing a symmetric distribution around mean value. Therefore within this confidence margin, the calculated additional reserve capacity for upward and downward regulation can be almost identical for both directions.

#### 6.5.4 Additional reserve requirements

The reserve requirement in each control area is increased from the present levels based on the wind penetration in that area. However, control areas are different in how the variability and predictability of wind power will impact the allocation and use of reserve as well as the cost incurred. Reference [106] presents the estimation of additional reserve requirement due to wind power penetration in Finland and Germany. The penetration of wind power is expressed as a percent-

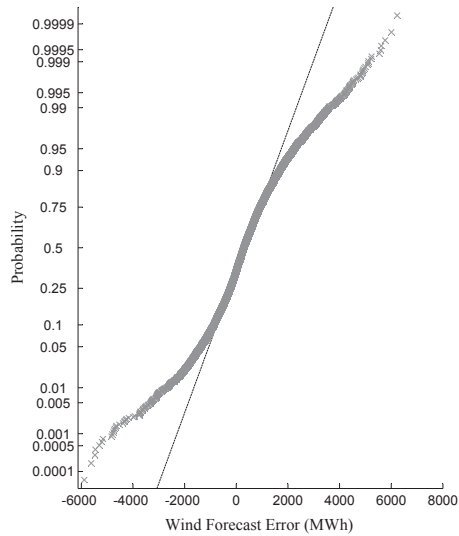


Figure 6.26: Assessment of wind power forecast error against normal distribution

age of gross demand in each control area. The estimate for Finland has been used for the other countries in the Nordic system. In [153], a probabilistic method has been applied for analysing the impact of increased wind production on reserve requirement within the Belgian power system. However, the authors used the Dutch wind speed data and the total installed wind capacity in their wind power development scenario, which almost corresponds to the data used for the Netherlands in 2030 in the data set used in this thesis. Therefore, the same numbers have been chosen for the additional reserve requirement in the Dutch power system. The upward and downward regulating reserves are estimated to increase by 1307 MW (16% of wind capacity in the Netherlands), whereas the downward reserves increase by 1443 MW (18% of wind capacity in the Netherlands); both for a scenario of 11% wind penetration in the Netherlands. Table 6.28 represents the increased reserve requirement in each country based on the wind power penetration.

Table 6.28: Estimated increase in reserve requirements (MW) based on wind penetration in northern Europe

	Wind 2030 (TWh)	Wind 2010 (TWh)	Diff. 30-10 (TWh)	Gross con. 30 (TWh)	Pen. (%)	Req. up (MW)	Req. dw (MW)
Norway	19	1	18	153	12	270	270
Sweden	23	1	22	163	14	513	513
Denmark	22	7	15	45	33	829	829
Finland	7	1	6	115	5	84	84
Germany	139	32	107	560	19	4385	4385

### 6.5.5 Social welfare concerns

As described in the previous chapters, it is important to distinguish between *cross-border reserve capacity exchange* and *balancing energy exchange*. *Cross-border reserve capacity exchange* requires the reservation of balancing energy outside the control area plus the availability of the corresponding cross-border transmission capacity. Both cross-border balancing energy and transmission capacity should be reserved during the reserve procurement phase. The utilisation of Nordic hydro power for balancing purposes requires the availability of enough grid capacity for power exchange. Therefore, the use of direct interconnections to transfer balancing services between control areas must be considered. In this regard, there will be a compromise between the interconnection capacity, which is allocated to reserve exchange, and the capacity allocated to energy exchange.

The Norwegian and Danish TSO's (Statnett and Energinet.dk) have agreed to reserve 100 MW of the capacity on the new HVDC cable connection between Norway and Denmark (Skagerrak 4) for balancing purposes [154]. Even though this allocation facilitates the exchange of balancing services between two synchronous systems, it may suffer from socio-economic losses in hours where the day-ahead market leaves less than 100 MW available capacity on the interconnection. The modelling approach presented in Chapter 5 handles this issue by including an implicit trade-off between the value of the interconnection in the day-ahead and balancing markets, reserving the optimal amount of interconnection capacity on an hour-by-hour basis.

### 6.5.6 Results and analysis

In order to study the effect of balancing market integration on reserve procurement and activation within the northern European system, two cases have been studied, as in the previous paper.

- Case I: Represents no balancing market integration. In this case, there is no possibility to exchange balancing services between the Nordic system and the central continental European system. However, balancing services can be exchanged between the Nordic countries.
- Case II: Represents the state of the system after full integration of balancing markets in the northern European market, where the balancing services can be exchanged system-wide.

A full integrated balancing market entails the harmonisation of the national balancing markets. For example, if Germany procures reserves from the Nordic region, there should be a mechanism in place to optimally allocate both reserves procured inside and outside of the German control areas. In order to implement a fair comparison between no-integrated and full-integrated case studies, similar assumptions are considered in the design of balancing markets in the analysis of both cases.

The summarized results of different market scenarios (Case I and Case II) on reserve procurement are represented in Table 6.29. The reserve requirement has been increased according to the values suggested in Table 6.28. As shown in Table 6.29 for Case II, an average of 2,676 MW of upward regulating reserves are exported per hour through the links between the Nordic and the continental systems. This represents approximately 30% of the required reserves in Germany and the Netherlands, shown in Table 6.31. However, there is only an export of 180 MWh of downward balancing reserves. The procurement cost is defined as the operation cost difference between a simulation case without and with reserve procurement. The procurement cost in Case II is reduced by EUR 226.4 million, which is 72% of the procurement cost for Case I.

Table 6.30 presents the results of system balancing. The activated reserves are reduced from Case I to Case II, showing the benefit of imbalance netting between different areas and increased wind power penetration in Case II, as shown in Table 6.33. The difference between imbalances and activated reserves in Case I is due to the imbalance netting of control areas within the Nordic system. In Case II there is an average export of 989 MWh for upward, and 277 MWh of downward, regulating reserves from the Nordic area to the continental system.

Table 6.29: The result of balancing market integration on reserve procurement in 2030

	Case I		Case II	
	Up	Down	Up	Down
Total reserve requirements [MW]	15181	-14354	15181	-14354
Average balancing services exchange [MWh]	0	0	2676	180
Procurement cost [M€]	315.7		89.3	

Table 6.30: The result of balancing market integration on system balancing in 2030

	Case I		Case II	
	Up	Down	Up	Down
Imbalances [GWh]	10772	-8739	10772	-8739
Activated balancing reserve [GWh]	10467	-8330	8935	-4817
Average activated balancing services exchange [MWh]	0	0	989	-277
Balancing cost [M€]	1758.6		1246.7	

The system balancing cost is reduced by EUR 512 million, corresponding to about 30% of the system balancing cost in Case I.

The average procured upward and downward reserves in each country are listed in Table 6.31. The main importer is Denmark with more than 80% of the required reserves. Norway provides the main share of exported upward balancing reserve, which is almost 76% of the total exported upward balancing reserves from the Nordic to the continental systems, whereas the rest is mainly procured by Sweden.

Table 6.32 compares the average activated reserves for both cases. In Case II, the total activated reserves for upward balancing has decreased by 12%, whereas the downward balancing is reduced by 40%. It appears that an average of 240 MW, 22% of the upward activated balancing reserves per hour, is exported from the Nordic system to the RG-CE system.

Table 6.31: Averaged annual per country procured reserves (MW)

Areas	Reserve req.		Case I		Case II	
	Up	Down	Up	Down	Up	Down
Sweden	1733	-1733	2289	-2218	2923	-2387
Norway	1470	-1470	2863	-2602	4996	-2539
Finland	949	-949	698	-789	734	-790
Denmark	2029	-2029	331	-571	204	-644
Nordic	6181	-6181	6181	-6181	8857	-6361
Germany	7393	-6430	7393	-6430	5142	-6477
Netherlands	1607	-1743	-1607	1743	1182	-1516
GE+NL	9000	-8173	9000	-8173	6324	-7993

Table 6.32: Averaged annual activated reserve in each country (MW)

Areas	Case I		Case II	
	Up	Down	Up	Down
Sweden	26	-125	47	-115
Norway	233	-28	447	-21
Finland	4	-85	7	-88
Denmark	14	-54	17	-75
Nordic	278	-292	518	-300
Germany	842	-624	505	-272
Netherlands	98	-58	39	-20
GE+NL	940	-682	544	-292
Total	<b>1217</b>	<b>-974</b>	<b>1062</b>	<b>-592</b>

The duration curves of activated reserves for the two case studies are plotted in Figure 6.27. System-wide activation of the balancing reserves increases the flexibility when using the Nordic hydro based power. Thus, more upward balancing power is activated in the Nordic area, which causes the Nordic duration curve in Case II to shift up, and the continental duration curve to shift down.

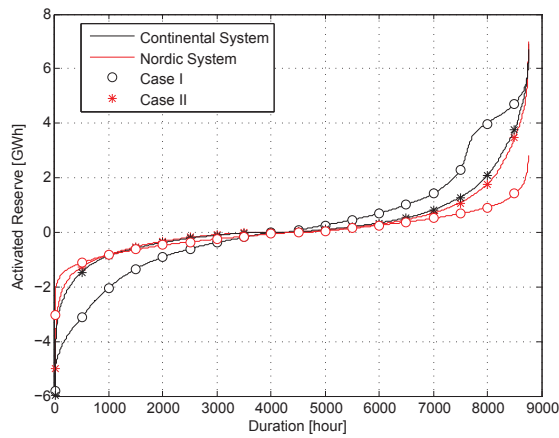


Figure 6.27: Duration curve of balancing reserve activation in Case I and II

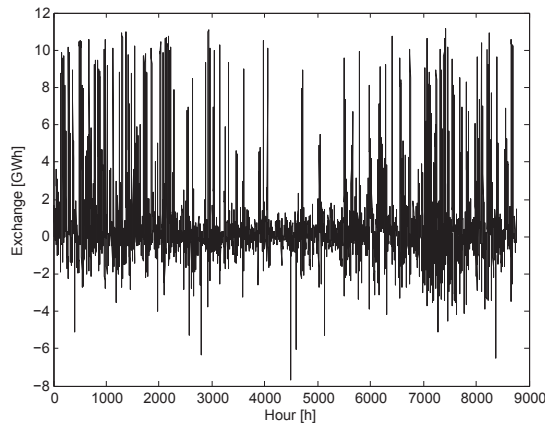


Figure 6.28: Exchange of balancing energy between the Nordic and the central continental European power system

The same effect is observed in downward balancing reserves activation. The gross activated reserve is reduced from 18,798 GWh to 13,753 GWh, and the annual exchange between the Nordic and the RG-CE systems is estimated to be 6,231 GWh in Case II.



Figure 6.28 shows the annual aggregated exchange of balancing energy for Case II. The difference between the day-ahead and real-time transmission exchange is equal to the exchange of balancing energy. The exchange varies between -8 and +11.5 GW during the year. In the summer time, the export of upward regulating reserves is lower than in winter time. This is caused by the high inflow into the Nordic reservoirs, resulting in low hydro water values (i.e., a low marginal cost of hydro generation due to filled reservoirs). Thus, it is optimal to use most of the interconnection capacity for the export of cheap hydro power within the day-ahead market.

In the future NE system, with an expected high penetration of variable production such as wind, flexibility of production will play an increasingly important role. Using a system-wide procurement and activation of balancing reserves enables a higher utilisation of the potential wind production at wind farms. Table 6.33 shows the potential wind production, (i.e. the wind production if there were no grid constraints) and the expected wind production for Cases I and II. Due to the increased production flexibility in Case II (obtained as a result of common sharing of the hydro power resources that have the ability to regulate output power faster and cheaper), wind penetration increases, which contributes to a reduction in day-ahead operating costs.

Table 6.33: Annual wind production in each country (TWh)

Areas	Potential Wind	Case I	Case II
Sweden	23.59	23.58	23.58
Norway	18.60	17.39	17.31
Finland	6.69	6.69	6.69
Denmark	21.59	21.58	21.58
Nordic	70.46	69.24	69.16
Germany	138.98	127.37	128.65
Netherlands	26.98	26.97	26.97
GE+NL	165.96	154.34	155.61
Total	<b>236.42</b>	<b>223.58</b>	<b>224.77</b>

A sensitivity analysis was performed by considering the effect of reserving 100 MW of capacity on the new Skagerrak IV interconnection for reserve purposes

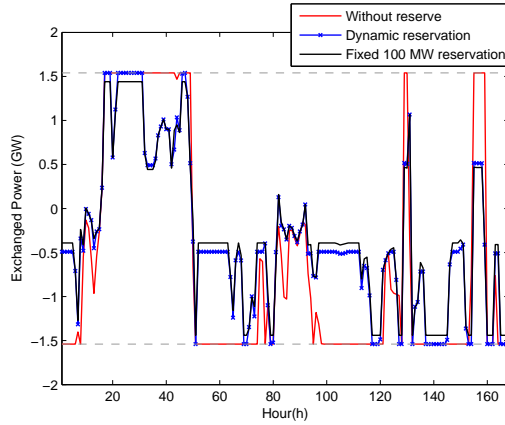


Figure 6.29: Cross-border energy exchange between Norway and Denmark, positive values mean flow from Norway to Denmark

(see Section 6.5.5). Figure 6.29 illustrates the simulated power exchange between Norway and Denmark in a typical autumn week (week 41). The dashed horizontal lines show the total corridor capacity in both directions. The results are compared against the case without reserve provision (without reserve, red line) where all capacity is exclusively allocated for energy exchange. The blue line represents the dynamic allocation of reserve, where the reserve capacity allocation is determined based on an hourly trade-off between day-ahead energy exchange and reserve capacity trade. The black line illustrates a case where the fixed 100 MW of exchange capacity is withdrawn from the day-ahead energy trade and reserved for balancing services exchange. In the occasions where the exchanged energy in dynamic reservation lies between the “fixed” and “without reservation” case it appears that the fixed reservation case bears a socio-economic loss in the day-ahead market.

The results show that a fixed reservation of transmission capacity increases the cost of procurement with approximately EUR 6 million. Note that the procurement cost is the difference between the total cost of dispatch with and without the reserve requirement. This cost increase therefore reflects the net effect of the reduced capacity in the day-ahead market, and the increased transmission capacity available for reserve procurement.

The duration curve of day-ahead power exchange between Norway and Denmark is plotted in Figure 6.30. The exchanged power in the day-ahead market

is reduced in the “fixed reservation” case (black bold) compared to the case with “dynamic reservation case” (red bold). The reduction in trading capacity in the day-ahead market represents a loss of trading opportunities in day-ahead, which will have a negative impact on social-welfare.

The total effect of the reservation also included the effect in the real-time balancing energy market, but that has not been calculated in this paper, and as such the net effect of the reservation is uncertain.

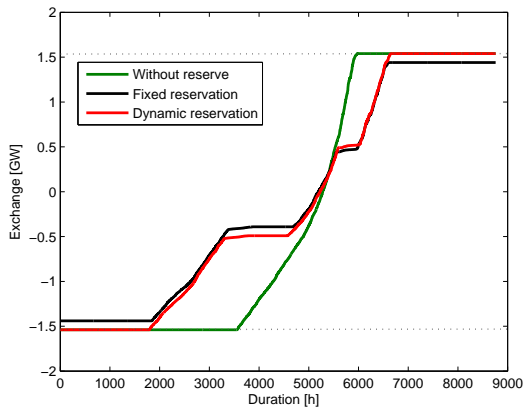


Figure 6.30: Duration curve of energy exchange between Norway and Denmark; positive values mean flow from Norway to Denmark

### 6.5.7 Discussion

The expected large-scale integration of wind power, especially from the North Sea, into the northern European power system brings along significant challenges for system planning and operation. Among those, the procurement of balancing reserves and system balancing play an important role. This paper focuses on the effect of balancing market integration on the procurement of balancing reserves and system balancing in the northern European system. Results indicate that integration of the balancing market provides an efficient opportunity for the continental system to utilize the Nordic flexible hydro power to reduce the activation of thermal generation, and hence reduce the cost of reserve procurement as well as system balancing cost. In the model, the procurement is reduced by 72%, and the balancing cost by 30% with respect to the non-integrated case.

Due to the significant share of hydro power plants in the Nordic production portfolio and the favourable properties they possess as balancing reserve resources, sufficient balancing reserves appear to be available in the Nordic system. However, limited available transmission capacity will not allow allocating all the required reserves to the Nordic system. The investigated scenarios address this issue under the framework of a joint market for energy and reserve capacity. This leads to better utilisation of the interconnections by avoiding socio-economic losses in the day-ahead market imposed by a fixed reservation of the corridors for reserve exchange. A case study of the Skagerrak IV link, between Norway and Denmark, with 100 MW reservation of capacity for reserve exchange, shows that with the integrated market assumed in this analysis the fixed capacity reservation probably results in a socio-economic loss, caused by the reduced interconnection capacity in the day-ahead market. However, there may be a gain in the real-time balancing energy market that was not calculated in this analysis.

## 6.6 Overview and Discussion of the Publications

In this chapter, the quantitative analyses of balancing market integration in the northern European balancing markets are presented. The analyses begin with the employing of IDC-OPF in the Nordic system, and continue with the comparison of the proposed methodology with the current practices in balancing markets. In this model, the active power losses are included through an iterative routine. Results show the improvement in the balancing cost, indicating the effectiveness of this model compared to the ones in current practice. The active power losses are neglected due to the high burden of calculation this imposes on the problem. As mentioned in Section 5.2.1, incorporating start-up cost increases the size of

problem a lot. Therefore, including the active power losses, which entails the iterative process impose high calculation burden. The active power losses are neglected to solve the problem in a reasonable calculation time. IDC-OPF is deemed to provide an underlying model for the further comprehensive analysis of balancing services activation in northern Europe. IDC-OPF is a fundamental model using the flow-based activation of optimal reserves, and has the possibility of being extended to larger geographical areas.

In the second paper the modelling of balancing markets, which includes a two-step optimisation, has been proposed. the modelling step in the first phase includes the day-ahead dispatch, where the required reserve in each control area is procured simultaneously with the day-ahead dispatch. As pointed out in this paper, hydro production, especially with large reservoirs, has the favourable properties that allow it to be procured for balancing reserve. However, they are mainly located in the Nordic system, and the network bottlenecks will not allow allocating all the required reserve in northern Europe to the Nordic system. Therefore, an important issue in the modelling step is the optimum allocation of interconnection capacities based on a trade-off between the exchange of balancing services and the day-ahead energy exchange. The second step of the modelling focuses on the optimal activation of reserves, based on the philosophy used in the IDC-OPF model presented in the previous paper. The results of two specific hours are presented in order to show the detailed description of the modelling. The results show that significant benefits could be reaped by the implementation of balancing market integration.

The next paper emphasises the methodology developed in the thesis for quantifying the potential benefits, i.e., socio-economic cost reduction. Implementing the proposed model for the simulated year of 2010 indicates that through the integration of balancing markets in the northern European area, there is a potential of EUR 400 million operational cost savings per year. The results include the optimal distribution of balancing resources in each control area together with the optimal exchange of balancing services. It is shown that through system-wide reserve procurement, an average of 0.9 GW of upward regulating reserve in the continent is procured in the Nordic system, representing approximately 30% of the required reserves in Germany and the Netherlands. On the other hand, the activated reserves are reduced by 31% through the effect of imbalance netting. The methodology has been implemented for the full integration of balancing market arrangement. However, it can be easily modified to capture the effect of different levels of balancing market harmonisation by changing the maximum reserve allowed to be procured from outside of the balancing area, according to the policies available in the system operation handbook [4]. The analysis shows

in detail how the dispatch of generating units and the exchange between areas vary for different levels of balancing market integration. This illustrates the profitability of the exchange of reserve between the synchronous systems using the existing HVDC interconnections.

In the last paper (Paper IV), the profitability of balancing market integration in the future scenarios of power systems with a high penetration of wind power production is estimated. The reserve requirement of each of the balancing areas will increase due to the penetration of wind production, based on the previous studies of this aspect. In order to capture the imbalances in the system, the wind forecast errors for 3-h ahead are selected instead of 24-h. The reason for this is that the trading part of the imbalances in intra-day market closer to physical delivery will help in reducing the forecast errors of wind power production, and will avoid an unnecessarily high balancing cost in the future scenarios of the power system. The annual expected operational cost saving is EUR 512 million, which is 30% of the system balancing cost. The average procured reserve in each country shows that Norway provides the main share of exported upward balancing reserves from the Nordic to the RG-CE system which is almost 76% of the total exported values. Also, it turns out that 24% of activated reserve is reduced due to the effect of imbalance netting. Another analysis carried out in this paper is on the comparison of the dynamic allocation of balancing exchange (on a daily basis) and fixed allocation (on a yearly basis) through an HVDC link between Norway and Denmark. The result indicates that the annual procurement cost would be increased by EUR 5.93 million in the fixed reservation case. This illustrates the socio-economic losses in reserve procurement imposed by the fixed reservation of the corridors for reserve exchange.

# Chapter 7

## Conclusions

### 7.1 Research Contributions

This thesis presents a methodology enabling the quantification of the potential benefits of implementing balancing market integration in the northern European power system. Most of the literature in this field focuses on market design and is concerned with the qualitative analysis of cross-border balancing. Relatively few references describe simulations and quantitative modelling of cross-border balancing, hence the need for a comprehensive analysis through the development of appropriate frameworks in this area.

Multinational balancing markets make it possible to increase security of supply, competition, and efficiency by enabling access to cheaper resources. They also provide the advantage of exploiting opposite imbalances in the neighbouring areas through the effect of imbalance netting. However, implementation of cross-border balancing entails a quantitative as well as a qualitative analysis of different balancing exchange scenarios for a detailed analysis of the challenges and potential benefits of cross-border balancing. Chapters 2, 3, and 4 encapsulate the foundational basis for the thesis. They concisely describe the introductory fundamentals, and study the prevailing practices and state-of-the-art in the European power systems in the sphere of balancing services. The remainder of the thesis is devoted to model formulation and case studies of the cross-border balancing services' procurement and activation in northern Europe. The methodology developed in the thesis enables the quantification of the benefits of integrating balancing markets not only within, but also between the Nordic and RG continental European synchronous power systems. The effect of the exchange of balancing services among the Nordic countries, Germany and the Netherlands

has been studied in detail.

The methodology includes a two-step model for the optimal procurement of reserve capacity and activation of balancing services, taking into account transmission constraints in the case of exchange between two synchronous areas. The two steps in the model represent a common clearing of the day-ahead and reserve capacity markets simultaneously, and the real-time balancing market, respectively. In contrast to the analyses that have been done on the integration of northern European balancing markets thus far, the model presented in this thesis explicitly addresses the transmission grid constraints through power flow equations. This fundamental model of the balancing market could also be suitable for the wider European power market with its highly meshed transmission grid. However, that goes beyond the scope of this thesis.

In the modelling steps different simulation models are employed. The water values as inputs to the day-ahead market are derived from the pre-existing EMPS model. PSST and SecOpt have been adapted to fit the requirements of the posed-problem. PSST toolbox has been modified to accommodate the model of day-ahead and reserve procurement simultaneously taking into account transmission capacity reservation for reserve exchange. SecOpt model is adapted in such a way to model the real-time reserve activation. Reserve procurement and reserve activation are the new issues modelled by these models within the scope of this PhD work.

## 7.2 Main Findings

- A model has been developed to simulate the exchange of balancing procurement and activation within and between synchronous systems. These are the Nordic system on the one hand, comprised of Norway, Sweden, Finland and Denmark, and on the other hand, the systems of Germany and the Netherlands .
  - Annual analysis of the post-integration scenario shows that more reserve is procured in the Nordic system, which is due to the high share of hydro power in its generation portfolio.
  - A per country distribution of the procured reserves shows that Norway and Sweden contribute more reserve. In Germany and the Netherlands there is a decrease in the procured reserve since part of their required



reserve is procured from the Nordic share through HVDC connections.

- With system-wide reserve procurement in 2010, an average 0.9 GW of upward regulating reserve in Germany and the Netherlands is procured in the Nordic system, representing approximately 30% of the required reserve in Germany and the Netherlands.
- The model includes day-ahead dispatch and unit commitment. Since the benefits of exchange between hydro and thermal systems to a significant degree result from the dynamics between high load and low load conditions, start-up costs have also been included in the analysis.
- The day-ahead model has been shown to give quite realistic results, although the price variations between high load and low load levels are somewhat less than what is seen in reality. A possible explanation may be the perfect market assumptions made in the model.
- The model is run on a daily basis, but extensive simulations have also been done for whole years. Implementing the proposed model for the simulated year of 2010 indicates that by the full integration of balancing markets in the northern European area, significant benefits could be reaped. The estimated potential saving is found to be around EUR 400 million. This saving is on account of both the reduction in reserve procurement, due to cross-border procurement of relatively cheaper services, and reserve employment, because of the imbalance netting and activation of cheaper reserves.
- The real-time market is modelled on the basis of the day-ahead simulation results using incremental DC power flow. The aim is to execute the necessary reserve activation to re-establish the system balance while minimising balancing costs. Therefore, the objective of the balancing market is purely to relieve imbalances in order to minimise operating costs in real-time, and not to generate an optimal re-dispatch. The simulation results in 2010 show that the activated reserves are reduced significantly (more than 30%) through the effect of imbalance netting.
- The suitability of hydro power for procuring balancing services, and its abundance in the Nordic system brings forward the potential for increasing production flexibility in light of increased renewable energy penetration in the future operation (in 2030) of the European power system. Applying

the developed model on a future power system (Nordic + RG continental European systems) with high wind power penetration and the expected offshore super grid in the North Sea shows that there is an almost three-fold significant increase in the balancing services exchange compared with what has been observed in the 2010 simulation scenario. The annual expected operational cost saving is found to be more than EUR 738 million. It is noted that there is no proportional increase when compared to the 2010 integrated scenario in cost savings. This is caused by the assumed commissioning of more transmission corridors between the Nordic and RG continental European systems, which reduces the price differences between the areas. Also, it turns out that 24% of the activated reserve would be reduced due to the effect of imbalance netting.

### 7.3 Scope for Future Work

Future work may relate to the modelling of an intra-day market between day-ahead and real-time markets. The variability and limited predictability of wind generation will impose high demand on generation adjustment in the future scenarios of European power systems. The more wind power generation, the more need to improve the balance of the market participants. Thus, the volume traded in the intra-day market is predicted to increase in the coming years. Hence, it is essential to analyse intra-day markets and their effect on balance management, especially for the studies of the future system scenarios. This can be done by re-dispatching the day-ahead results, taking into account the possibility of exchanging energy between control areas.

It is anticipated that there might be a new interconnection between the Nordic system and the UK. Future work could focus on the inclusion of the UK in the cross-border balancing of the northern European system. A challenging issue in this regard is the rather different organization of the UK market.

Further work could finally focus on the effect of smart grids on balance management. In this connection, consumers will be able to control their electricity consumption in an automated way. The involvement of electricity consumption in real-time balancing can significantly change the current practices of system balancing, necessitating the inclusion of the active participation of demand in real-time balancing studies.

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# Appendix A

## DC Power Flow Calculation

### A.1 DC Power Flow

One of the main features of the modelling approach in this thesis is the use of power flow and the power exchange between the different buses and areas. Power Flow is carried out to calculate the flow of the power in the network (from generators to loads) according to the physical laws, while holding the voltage and current inside allowed intervals. It analyses the power systems in the normal steady-state operation.

The assumption of a linear DC power flow is often used in optimisation problems of power markets when the effect of the transmission networks is taken into account. In most of these models, the focus is on power economics rather than on the exact modelling of the power flow. Instead of using non-linear AC power flow equations, the most critical cases in the transmission network can be captured by the DC power flow approximation. Moreover, the linear DC power flow equations retain the convexity of optimisation problems and are faster to be solved without using iterative processes. This feature is of great value in the operation and planning of electric power systems.

Figure A.1 shows a two-bus system, and equivalent circuit of a transmission line, between bus  $i$  and bus  $j$  with a lumped parameter represented by the series impedance  $Z_{ij}$ .

The transmission line is characterised by series impedance and shunt admittance, where the following equation describes these lump parameters [2]:

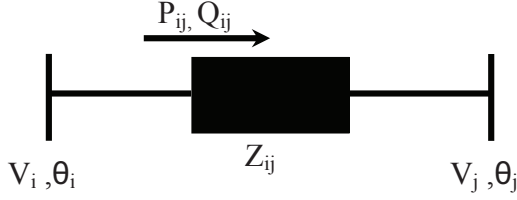


Figure A.1: Transmission line between buses  $i$  and  $j$

$$Z_{ij} = R_{ij} + jX_{ij} \quad (\text{A.1})$$

where  $R_{ij}$  and  $X_{ij}$  are the series resistance and reactance between buses  $i$  and  $j$ , respectively. In the power flow calculation, usually the admittance is used instead of impedance. The conversion of impedance to admittance is presented in Equation (A.2).

$$Y_{ij} = Z_{ij}^{-1} = G_{ij} + jB_{ij} = \frac{R_{ij}}{R_{ij}^2 + X_{ij}^2} - \frac{X_{ij}}{R_{ij}^2 + X_{ij}^2} \quad (\text{A.2})$$

where  $G_{ij}$  and  $B_{ij}$  denote the equivalent conductance and reactance of the transmission line between buses  $i$  and  $j$ , respectively. The active and reactive power flows from bus  $i$  and bus  $j$  are obtained as follows [2]:

$$P_{ij} = V_i^2 G_{ij} - V_i V_j G_{ij} \cos(\theta_{ij}) - V_i V_j B_{ij} \sin(\theta_{ij}) \quad (\text{A.3})$$

$$Q_{ij} = -V_i^2 B_{ij} + V_i V_j B_{ij} \cos(\theta_{ij}) - V_i V_j G_{ij} \sin(\theta_{ij}) \quad (\text{A.4})$$

where  $V_i$ ,  $V_j$  and  $\theta_i$ ,  $\theta_j$  are voltage magnitudes and angles, respectively. Besides,  $(\theta_{ij}) = \theta_i - \theta_j$ .

The major approximation in a DC power flow is the neglecting of reactive power, and assumption of a flat voltage profile at all nodes (all voltage magnitudes are equal to 1.0 per unit) which is particularly the case for light load condition. Additionally,  $\theta_{ij}$  is assumed to be small. Hence, the following approximations

are valid [2]:

$$V_i \approx V_j \tag{A.5}$$

$$\sin(\theta_{ij}) \approx \theta_{ij} \tag{A.6}$$

$$\cos(\theta_{ij}) \approx 1 \tag{A.7}$$

Furthermore, the resistance of each transmission line is neglected. Therefore,  $G_{ij} = 0$  and  $B_{ij} = -\frac{1}{X_{ij}}$ . The expression for active power flow, stated in Equation (A.3), can be simplified to:

$$P_{ij} = \frac{\theta_{ij}}{X_{ij}} = \frac{\theta_i - \theta_j}{X_{ij}} \tag{A.8}$$

Figure A.2 illustrates the simplified transmission line model between buses  $i$  and  $j$ . It is analogous to Ohm's law applied to a resistor with a DC current, where  $P_{ij}$  denotes the DC current,  $\theta_i$  and  $\theta_j$  are the DC voltages at both ends of the resistor, and  $X_{ij}$  is the resistance.

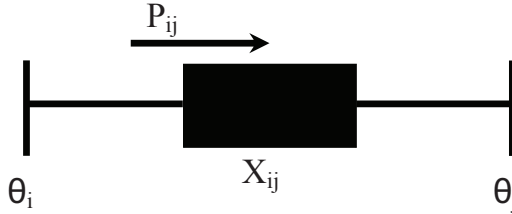


Figure A.2: Simplified DC power flow representation of transmission line