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Science and Technology

Flow based market clearing: estimation of net positions

Ragnhild Aker Nordeng

Master of Energy and Environmental Engineering
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Supervisor: Gerard Doorman, ELKRAFT
Co-supervisor: Jan Hystad, Statnett

Norwegian University of Science and Technology
Department of Electric Power Engineering

NORGES TEKNISK-NATURVITENSKAPELIGE UNIVERSITET

NTNU

M A S T E R O P P G A V E

Kandidatens navn:	Ragnhild Nordeng Aker
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Oppgavens tittel (norsk):	**Flytbasert markedsklarering: estimering av nettoposisjoner**
Oppgavens tittel (engelsk):	**Flow based market clearing: estimation of net positions**

Oppgavens tekst

Marketsklareringen i Nord Pool skjer i dag etter den såkalte NTC-metoden (Net Transfer Capacity). Med denne metoden tas det ikke hensyn til de elektriske egenskapene til nettet. Det arbeides nå med såkalt "flytbasert markedsklarering", som er en metode som i noe større grad tar hensyn til det fysiske nettet. Dette skal gi markedsløsninger som er nærmere den fysiske realiteten og dermed både utnyttelse av nettet mens driftssikkerheten beholdes på et høyt nivå. Som grunnlag for modellen man skal regne på, må man estimere såkalte "nettoposisjoner", dvs områders netto eksport, samt flyten på DC kablene. En mulig framgangsmåte er å bruke markedsdata hos Nordpoolspot og modifisere dem. Kraftbørsene tilbyr en "Simulation Facility" for dette, og hovedformålet med oppgaven er å teste ut denne.

I prosjektoppgaven ble det gjort initielle analyser for fire enkeltdøgn. I masteroppgaven skal dette arbeidet utvides ved å ta hensyn til flere faktorer, samt å analysere flere døgn. Følgende skal gjøres:

1) Ta hensyn til endringer i kapasitetene mellom Elspotområder fra referansedagen til beregningsdagen
2) Gjør en dypere analyse av enkelttimer med store avvik for å finne årsakene til avvikene. Se f.eks. på prisforskjeller mellom områder, flyt ut av Norden, store skift i enkeltområder osv.
3) Inkluder endringer i vind (og helst også sol) produksjon i Tyskland.
4) Inkluder endring i kjernekraftproduksjon. Denne er normalt også meget forutsigbar. Dette betyr ikke nødvendigvis noe for de døgnene som er kjørt så langt, men kan være viktig noen ganger.
5) Vurder sammen med veilederne om eventuelle andre faktorer bør tas med i analysen
6) Gjør en analyse med 2-uker gamle data og sammenlign kvaliteten
7) Gjør en analyse for en eller flere lange perioder (helst hele 2015) og dokumenter resultatene på en hensiktsmessig måte.

Utført ved (institusjon, bedrift):	Institutt for Elkraftteknikk Eksterne kontakter: Jan Hystad, Statnett
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Faglærer: Gerard Doorman

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Preface

This master thesis concludes my final year as a master of science student within the field of Energy and Environmental engineering at The University og Science and Technology (NTNU). The thesis is written in cooperation with Statnett SF, and is finalized during the spring of 2015.

I would like to thank my supervisor Gerard Doorman and co-supervisor Jan Hystad with support and guidance through the project. In addition, I would also like to thank Nils Flaten Ræder from Statnett for taking care of me during a several days visit in Oslo, ans Daniel Stølsbotn at Nord Pool for this great support while working with the simulation tool "Simulation Facility".

Trondheim, 2016-06-17

Ragnhild Aker Nordeng

Summary

Together with the other Nordic transmission system operators Statnett is currently investigating the possibility of implementing the so called Flow Based Market Clearing approach. Flow Based Market Clearing is today the preferred market clearing method by the European Commission, and is already introduced in the Central Western European countries. The approach maximizes social surplus while introducing a simplified grid model as a part of the market clearing algorithm. This is the main difference compared to today's Net Transfer Capacity allocation method, where the physical network flows are not implemented in the optimization problem. The new market clearing approach gives a more efficient system, increases the network flow, and keeps the system security at a satisfactory level.

As a foundation for the Flow Based Market Clearing model the transmission system operator has to make estimations of future production and consumption in each bidding area. These estimations form the areas net position, i.e. the areas net export. This projects main objective is to develop a methodology for a new method for estimation of net positions.

The developed estimation approach assumes that the Day-ahead market curves mainly consists of two parts; One part represented by price dependent bids, and one part represented by non-price dependent bids. It is further assumed that the flexible part of the market curves is roughly the same from one day to the next, and the changes that do occur are related to marked bids that are not effected by price changes, e.g wind and solar power production. The change in these bids will therefore cause parallel shifts to the market curves. The developed method aims to identify these price in-depended bids and uses them to make forecasts of future net positions. The forecasted net positions are found with the market clearing algorithm Euphemia, which is offered through the simulation tool "Simulation Facility".

Two initial test were carried out to test the new estimation approach. One with up-to-date data, and one with a data foundation that is two weeks old.

The results from the initial tests indicate that the new estimation method can give positive results compared to other possible methods. In order to keep the system security at a satisfactory level, it is important to reduce large errors. The simulation results indicate that large error are reduced, however a few very large error do occur with the new method for the tested case.

Sammendrag

Sammen med de andre nordiske systemansvarlige undersøker Statnett muligheten for implementering av Flytbasert Markedsklarering i det nordiske kraftmarkedet. Flytbasert Markedsklarering er i dag den foretrukne markedsklaringsmetoden i EU, og er allerede innført i flere europeiske land. Tilnærmingen maksimerer sosialt overskudd ved å innføring en forenklet nettmodell som en del av modellens algoritme. Dette er den største forskjellen sammenlignet med dagens NTC-modell (Net Transfer Capacity), hvor den fysiske kraftflyten ikke er implementert i optimaliseringsproblemet. Den nye metoden gir et mer effektivt system, øker flyten av kraft mellom områder, og holder systemsikkerheten på et tilfredsstillende nivå.

Som et grunnlag for den nye modellen må Statnett utføre beregninger knyttet til fremtidig produksjon og forbruk for hvert enkelt budområde. Beregningene danner områdets nettoposisjon, dvs. områdets netto eksport. Hovedmålet til denne masteroppgaven er å undersøke og vurdere en ny metode for estimering av disse nettposisjonene.

Estimeringsmetoden forutsetter at markedskurvene i kraftmarkedet hovedsakelig kan deles opp i to deler, en del som representerer prisavhengige bud, og en del som representerer alle prisuavhengige bud. Metoden forutsetter videre at den fleksible delen av markedskurvene forblir omtrent den samme fra en dag til den neste, mens de endringene som oppstår er antatt å hovedsakelig være knyttet til bud som ikke er prissensitive, f.eks produksjon fra vind- og solkraft. Det er antatt at endringen av disse budene vil føre til en parallellforskyvning av markedskurvene fra en dag til den neste. Målet til den nye metoden er å identifisere tidligere nevnte prisuavhengige bud og bruker dem til å lage prognoser for fremtidige nettoposisjoner. De forventede nettoposisjoner blir funnet ved å bruke markedsklareringsalgoritmen Euphemia, som tilbys gjennom simuleringsverktøyet "Simulation Facility".

For å teste metoden ble det gjennomført simuleringer av to ulike caser. Den første casen bruker et oppdatert datagrunnlag under simuleringen, mens den andre bruker et datagrunnlag som er to uker gammelt.

Resultatene fra de innledende testene kan typde på at den nye estimeringsmetoden gir positive resultater sammenlignet med andre andre tilgjengelige metoder. For å holde systemsikkerheten på et tilfredsstillende nivå, er det viktig at metoden redusere store feil. Simuleringsresultatene indikerer at store feil blir generelt redusert, men mer undersøkelser burde gjøres.

Contents

Abbreviations

AC Altering Current

CNE Generation Shift Key

CWE Central Western Europe

DC Direct Current

DK Denmark

ENTSOE European Network of Transmission System Operators of Electricity

EUPHEMIA Pan-European Hybrid Electricty Market Integration Algorithm

FAV Final Asjustment Value

FB Flow Based

FBMC Flow Based Market Clearing

FI Finland

GSK Generation Shift Key

NO Norway

NP Net Position

NTC Net Transfer Capacity

PTDF Power Transfer Distribution Factor

PX Power Exchange

SE Sweden

SF Simulation Facility

TSO Transmission System Operator

UMM Urgent Market Messages

1. Introduction

This chapter gives an introduction to the specialization project and defines the problems fomulation.

1.1 Background

Until now, the Nordic Power Exchange have used a market clearing model called the Net Transfer Capacity allocation model (NTC), this is however changing. Together with the other Nordic Transmission System Operators (TSO) Statnett is currently investigating the possibility of implementing the so called Flow Based Market Clearing (FBMC) approach in the Nordic market. FBMC is today the preferred market clearing method by the European Commission, and is already introduced in the Central Western European countries. The approach maximizes social surplus while introducing a simplified grid model as a part of the market clearing algorithm. This is the main difference compared to today's NTC method, where the physical network flows are not implemented in the optimization problem. The new market clearing approach gives a more efficient system and increases the network flow. Before a potential Nordic launch there are still parts of the FBMC approach that need further study. For example, as a basis for the model, one has to estimate so called "net position", i.e. the areas net export [1], as well as the power flow on the DC cables. One possible approach of finding these properties is to use marked data collected from Nord Pool (Nordic Power Exchange) and modify it. The Power Exchange offers a "Simulation Facility" for this, and the thesis main objective is to test this method.

Over the past several years energy from non-regulating renewable resources, e.g. wind and solar power, have become an increasing part of the supplied energy to the power market. Together with temperature dependent consumption, these resources can be difficult to predict and does not necessarily have a dependable pattern. Since large changes in production and consumption can occur over a short period of time, the expected net positions calculated by

[1] Net Position = Supply - Demand

the TSO for each bidding area in the FBMC approach can turn out to be inaccurate.

In the FBMC approach the TSO starts the transmission system capacity calculations two days before market clearing. Before 10:00 the next day the final values are provided to the market. These values form the systems base case and, among others, includes expected net positions for all bidding zones. The forecast is then handed to Nord Pool. Flow on each transmission line and predicted margins in the market are calculated together with the expected base case.

If the expected net positions differ from the real net positions, utilization of the transmission system can be insufficient. Very large deviations can even threaten the system reliability. Uncertainty of future production and consumption is therefore not only important in a welfare economic point of view, but also in a security point of view.

1.2 Project formulation

Due to the increasing amount of renewable energy supply in the Nordic market, system production and consumption forecast is getting more difficult. With the FBMC uncertainty in the net position forecasts can affect the system reliability and the amount of available grid capacity allocated to the power market.

There is no straightforward way to give precise estimations of net positions, and the Nordic TSOs are therefore currently investigating several different approaches. The Nordic TSOs believes that their net positions are closely related, and it is therefore seen useful to determine the all values in one procedure [1]. The initial evaluated approaches were:

- Use a selected reference day
- Regression against a number of relevant variables
- Similar Net Demand
- Euphemia based

The main objective of this project is to start the evaluation of the last of these methods, the Euphemia based approach. This approach estimates the net positions by using available market data and the market clearing algorithm Euphemia through the simulation tool "Simulation Facility" (SF). Until now, there has been no similar program for modeling of the market available. Hence, this report also makes an evaluation of how well SF work for this type of approach.

Objectives

During the fall of 2015 preliminary research for four single days was carried out. The master thesis continues this work by adding more factors to the model, and testing the estimation approach for longer time periods.

The main objectives of this project are:

1. Account for the transmission capacity changes between the Nordic bidding areas from the reference day and operation day.
2. Execute a thorough analysis of single hours with large deviations in order to find the cause of these errors.
3. Include changes in wind and solar production in Germany in the model.
4. Include changes in Nordic nuclear production.
5. Evaluate if there are more changes that are needed in the model.
6. Execute a similar analysis, but with data that is two weeks old.
7. Make an analysis of longer time periods, for example all of 2015.

Limitations

For the FBMC approach one would use data forecasts that are obtained two days prior to the operational/simulation day. Large shares of this data is currently not available and most of the collected data files used in this research was real market data, giving a "perfect foresight". This might lead to a limitation in the study, but it is however emphasized that market data was used during the project, and not measured data. The market data is a forecast from one day prior to the operational day, and it is therefore assumed that some of the wanted uncertainty related to forecasted data is included in the evaluated simulations. It was not possible to obtain market data for all parameters, and measured data was used instead.

When utilizing the program Simulation Facility, the simulation tool uses the hole Price Coupling of Regions area in the simulation. This includes countries such as Italy, Spain and Monaco. In order to reduce the amount of manual calculations a simplified topology was used for the simulation. This might cause a limitation to the project, but it was seen as a reasonable simplification since the main focus of this thesis are the main trends during a longer simulation period.

Some data used in this project is confidential and is therefore censured in the report.

1.3 Existing literature and ongoing work

The theory and methodology of Flow Based Market Clearing is well documented and investigated, and different methods for reducing the uncertainty in the model are being explored.

In the paper "Methodology and concepts for the Nordic Flow-based Market Coupling Approach" [2] the Nordic TSOs [2] discuss uncertainty and possible limitations to the FB methodology. The authors argues that there are several ways to deal with this uncertainty and large shifts in net positions. On suggestion is "to opt for more robust generic GSK strategy" [2], another way can be to develop more accurate weather forecasts.

There are several papers denoted to the theory and implementation of the method. "Methodology and concepts for the Nordic Flow-Based Market Coupling Approach" [2] developed by the Nordic TSOs, gives a thorough description of the flow based capacity calculation methodology in general and specifically in the Nordic region. The report is part of the Nordic Flow Based Feasibility Study part 1. This study also includes a report on the "Principle approach for assessing Nordic Welfare under Flow-Based methodology" [3]. The papers do not go into the details of specific estimation methods, but states that further investigation on the subject is needed.

There is limited literature aimed directly to the different methods dealing with estimation of net positions. The approach presented in this report is new, and has not been tested prior to this project. As described earlier, research of finding the best approach for estimation of net positions is an ongoing project, and there is therefore limited published papers directly aimed to this study. There is a memo currently being developed [1], but it is still in the making and is not completely finished. The memo briefly describes the ongoing work on the estimation of net positions for the Common Grid Model project. Four estimations approaches were initially considered, and this master thesis evaluates one of them. The three others are the "Reference day approach", The "Regression against a number of relevant variables" and the "Similar Net Demand approach ". As described in [1], using a reference day is a very simple and easy approach, but it might not give satisfactory results. The Memo [1] points out that the regression approach was initially seen as very relevant, but it requires significant effort to develop.The Similar Net Demand was instead developed, and lead to a significant improvement of the results compared to the reference day.

There have been studies investigating methods offering more accurate wind forecasts. For example: In [4] Olauson and Bergkvist presents a model where MERRA [3] reanalysis data and information on wind energy converts are used as inputs for the generation of wind power

[2]Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland), and Energinet.dk (Denmark)
[3]MERRA: Modern-era retrospective analysis for research and applications

time series in Sweden. Comparing the results with data from the Swedish TSO the mean absolute error in hourly energy for this study was 2.9 % compared to the actual production from 2007 to 2012.

The FBMC approach is already launched in the Central Western European region, and there are several available reports for the method and results from this area. In the article "The Flow-Based Market Coupling in Central Western Europe: Concepts and Definitions" [5], Bergh, Boury, and Delarue briefly explains the net positions estimation used in these countries. For this region, the local TSO uses a market solution from a reference day and updates this solution for generation forecasts, load forecasts, and scheduled outages. Each TSO uses slightly different techniques when updating the reference day values.

Several master thesis at NTNU the past years have been denoted to a possible Nordic implementation of Flow Based Market Coupling, [6], [7], and [8]. The main focus of these theses are however on other Flow Based Market Clearing subjects than estimation of net positions. In [8], Birgit Jegleim investigates different generation shift key (GSK) strategies and which gives the most accurate power flows in the flow based approach. A similar research is further investigated by Vegard Bremerthun Svarstad during the spring of 2016.

1.4 Structure of the Report

The rest of the report is organized as follows: First, there is a introduction to the most relevant theoretical concepts in chapter 2, before a brief description of the the flow based market clearing approach in 3. In chapter 4 the constructed simulation method is presented, and the studied simulation cases are described in 5. The main results are presented and discussed in chapter 6. The report ends with a presentation of some additional study in Chapter 7, and a conclusion of the project and recommendations for future work in Chapter 8.

Parts of the presented report is reused from the project thesis carried out by the author during the fall of 2015. The written material is however in some extend edited and changed in order to match the topics and scope of the master thesis.

2. Theoretical background

This chapter gives a brief description of the most relevant theory in this master thesis, and serves as a theoretical supplement for the other chapters. Most of the presented topics are in general well documented in other literature and master theses, and if the reader is curious on the subject further reading is recommended, e.g. [6] and [8].

2.1 The Nordic power market

Nord Pool serves today as the Nordic markets Power Exchange and is the only common market place for electricity exchange in the region. Nord Pool is a collaboration between the Nordic countries: Norway, Sweden, Denmark and Finland and the Baltic countries: Estonia, Latvia and Lithuania.[9]

The main responsibilities of the Power Exchange is to manage the physical and financial trade in the Nordic system. This includes the Day-ahead market (Elspot), intraday market (Elbas) and the financial market (Nasdaq OMX Commodities) [10]. Approximately 370 companies from 18 different countries trade at the Nordic Power Exchange [11].

This report will only focus on the Elspot Day-ahead market, because this is most relevant for the scope of the thesis. If the reader is interested, [10] can be recommended for further description of the other Nord Pool markets.

2.1.1 Elspot: Day-ahead market

The Elspot Day-ahead market is the main market place for physical power trade in the Nordic region, and most of the 360 members trade power at a daily basis. [9]. The Day-ahead market is organized as an auction, and the daily auction process consists of several steps. A time line of the process is illustrated in Figure 2.1.

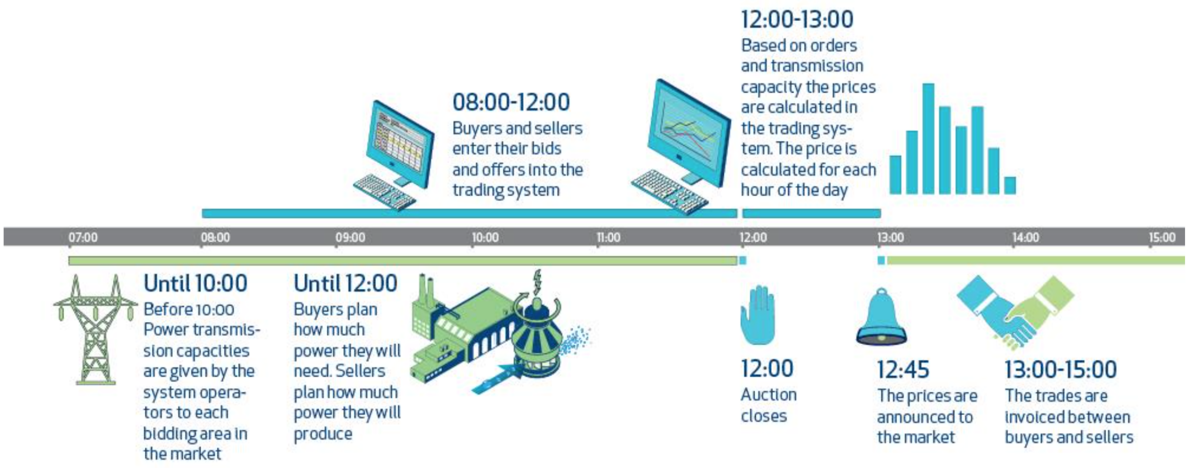

Figure 2.1: Illustration of the Elspot Day-ahead market process throughout one day. Figure is collected from [12]

Before noon every week day buyers and sellers place their offers and bids to Nord Pool for the following day. At noon the auction closes and Nord Pool starts the calculations of area and system prices. The calculations are based on the placed orders as well as transmission capacities. As illustrated in Figure 2.1, the transmission capacities for each bidding area are provided from the TSO before 10:00 every day. The system and area prices for the following day are announced at 12:42, and between 14:00 and 15:00 trades between buyers and sellers are invoiced [13].

Order Types

There are three main order/bid types in the Elspot market; Single hourly bids, block bids and flexible one hourly bids. The single hourly bids are the most common and basic type of Elspot market orders. The price and volume are given separately for each hour and the order must contain the theoretical minimum and maximum price levels [11].

Block bids are often referred to as an all or nothing order. An example can be a supply bid that has a duration of three hours. If the average price is higher then X EUR/MWh between 07:00 and 10:00, the bid is accepted. If the average price is lower than X EUR/MWh, the bid is declined. Block bids are often useful for participant with inflexible production or consumption. This can for example be supply units with high start-up and shut-down cost. A block order has a minimum quantum level of 1 MW and has to have a duration of at least three hours [11].

Flexible one hourly bids are limited to sales bids. A flexible one hourly bid only contains price and volume. Therefore, these type of bids can add flexibility to the system and is accepted for the hour that gives the optimal solution.[11]

Settling the system price

After the action is closed all marked bids are collected, and Nord Pool starts the system price calculations. All market prices are calculated for each hour of the upcoming day.

The system price is settled by finding the equilibrium between the aggregated supply and demand curves for the total power market. The aggregated market curves are established by combining all market bids into supply and demand curves. The supply curve consists of all selling bids placed in the auction, while the demand curve represents all buying offers [9] [14]. A simple illustration of the marked curves and market equilibrium are illustrated in Figure 2.2.

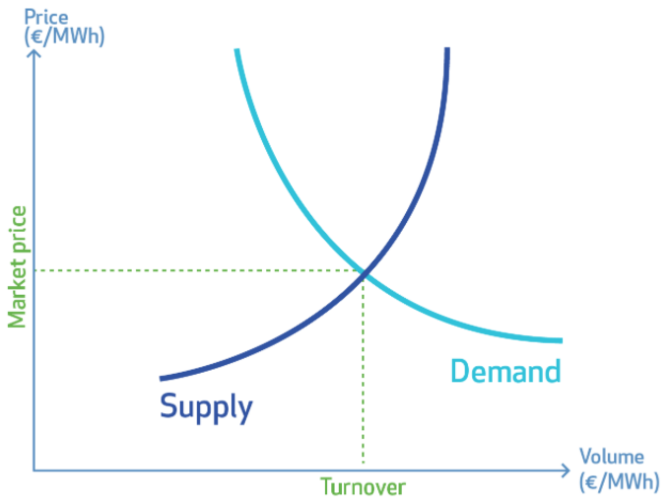

Figure 2.2: Simple illustration of how the system price is settles by using the aggregated market curves. The figure is collected from [9]

2.1.2 Elspot bidding areas and congestion handling

The Nordic countries are divided into different Elspot bidding areas by the local TSO. While calculating the system price Nord Pool assumes that there are no transmission constraints in the power network. This assumption is however rarely valid, and by dividing the market the bidding areas reflect the different Elspot market conditions. The different areas also reflects the transmission system constraints in the power network [15]. The number of bidding areas can vary. There are currently 12 bidding areas in the region, excluding the Baltic countries. Figure 2.3 gives an illustration of the current Elspot bidding areas.

Based on the availability of transmission capacity, the transmission of power can be con-

Figure 2.3: Illustration of the Nordic Elspot bidding areas. Picture is collected from [15].

gested and lead to price deviations between the bidding areas [10]. Figure 2.4 gives a simple illustration of how congestion between to areas can lead to various prices.

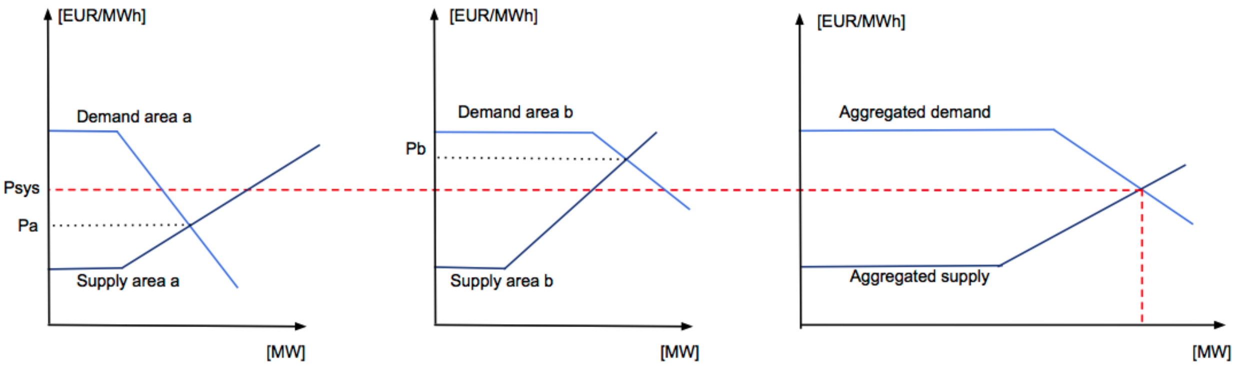

Figure 2.4: Illustration of how several bidding areas can have different prices. Picture is inspired by picture in [10].

The aggregated supply and demand curves, on the right in Figure 2.4, for area (a) and (b) sets the system price. While calculating the system price it is assumed that there is infinite transmission capacity between all bidding areas. This creates a surplus area (a) and a deficit area (b), where the excessed power is export from area (a) to area (b). If there is no available transmission capacity the individual areas have to adjust, and produce/consume power according to the individual equilibrium point. As seen from the figure the price is reduced from Psys to Pa in the surplus area, and increased for the deficit area. When there are price differences between the individual bidding areas the social welfare decreases. This should creates an incentive to have as few bottlenecks as possible in the power system, and hence keep the total social welfare at a hight level.

2.1.3 NTC - Todays market clearing approach

This section gives a very brief introduction to the current market clearing model. However, in [16] the European Network of Transmission System Operators of Electricity (ENTSO-E) gives a thorough explanation of the method and presents examples from the Nordic power market.

Net Transfer Capacity allocation is the current market clearing model in the Nordic power market, and is defined as the difference between the Total Transfer Capacity (TTC) and the Transmission Reliability Margin (TRM) [16]. The relation is presented in equation (2.1).

$$NTC = TTC - TRM \tag{2.1}$$

The Transmission Reliability Margin represents a security margin related to the uncertainty in the computed Total Transfer Capacity. The Total Transfer Capacity is the "maximum transmission of active power in accordance with the system security criteria." [16]. For the NTC method, the characteristics of the physical power grid are strongly simplified. The system capacity is allocated prior to the market clearing, and only commercial exchange between bidding areas is considered in the market algorithm [2].

The NTC is calculated based on the TSO assumptions of the potential market outcome and physical flows. Because of the assumptions that are made in the model, the transmission capacities made available for the market are often a conservative estimate compared to the actual capacities. This is in order to reduce the risk of physical overload [5].

2.2 Price Coupling of Regions

Price Coupling of Regions (PCR) is a pan European project withe seven Power Exchanges covering 13 TSOs. The main objective of the project is that all area prices and flows in the hole region are calculated in the same price calculation algorithm[11]. On February 4^{th} 2014 the PCR method was implemented, and is today seen as an important step to achieve the overall EU target of a harmonized European electricity market [17]. Figure 2.5 gives an illustration of the European area covered by the PCR project.

The common electricity market is assumed to "maximize the overall social welfare and increase the transparency of the computation and price."[19]. It is important to emphasize that even though there is a common system design with the PCR project each Power Exchange is

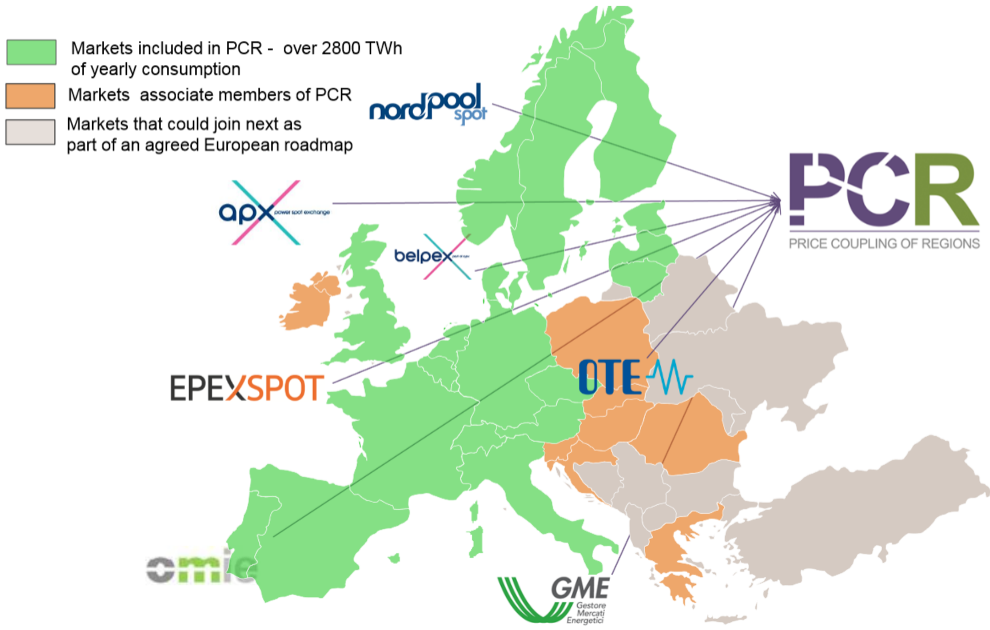

Figure 2.5: European area covered by PCR. The green area represents markets already included in PCR, the orange area are markets associate members of PCR, and the grey area represents markets that could join PCR at a later stage. The figure is collected from a Nord Pool presentation on the PCR Project [18]

still responsible for their own operation and markets [11].

The developed price calculation algorithm is called Euphemia and is further explained in the next section, Subsection 2.2.1.

2.2.1 Pan-European Hybrid Electricity Market Integration Algorithm (Euphemia)

In order to achieve the integrated European electricity market a new algorithm, Euphemia [1], was developed. The new algorithm cover all requirements from the different coupled markets and gives the market solutions within a reasonable time frame.

The main objective of the algorithm is to maximize social welfare. When the optimization problem is solved Euphemia returns prices, volumes, net positions and flows on each interconnection. The algorithm also gives information regarding the selected market bids.

Due to the complexity of the different marked bids, e.g. complex[2], block and PUN orders[3],

[1] Pan-European Hybrid Electricity Market Integration Algorithm
[2] Complex Orders: supply orders used in the Spanish and Portuguese market[20]
[3] PUN-Orders:Special demand orders used in Italy[20]

the optimization problem is quite complex and can not be solved using simple optimization methods. As explained in the Euphemia public description[19], Euphemia instead runs a combinatorial optimization processes that contains four different stages. The stages consists of one masters problem and three independent sub-problems. The three sub-problems consists of: price determination sub problem, the PUN search sub-problem and the volume indeterminacy sub-problem. Figure 2.6 illustrates the optimization approach used by Euphemia. The algorithm uses a branch and cut method to explore the solution space and find the optimal solution [19].

Euphemia starts the calculations by solving the master problem. The problem is still treated as a welfare optimization problem, but the complexity is reduced by relaxing the binary variables on block and complex orders. After a integer solution is found, the algorithm solves the price determination sub problem. At this stage Euphemia finds the market price for each bidding area while making shore that there are no paradoxically accepted block orders and no adverse flows[4] [19]. If there is no feasible solution to the sub problem Euphemia will cut the investigated integer solution and go back to the master problem. The masters problem is then altered according to the newly introduced cut. [19]

If the price determination sub-problem is feasible Euphemia moves on to the PUN search sub-problem. At this stage volumes and prices for PUN orders are found while satisfying the different constraints in the optimization problem. If the solutions does not introduce any new paradoxically accepted complex or block orders Euphemia continues to the last sub-problem. If not, a cut is introduced and Euphemia moves back to the master problem.

During the price determination sub-problem feasible combinations of prices and volumes for the market are found. There might be several combinations of aggregated bids, flows and net positions that give the same feasible social welfare. The Volume indeterminacy sub-problem therefore decides the specific solution by empathizing maximization of traded volume, the merit order and price-taking orders. When the sub-problem is finished Euphemia will try to improve the solution by expanding the solution space and investigating a new branch in the model [19].

The algorithm stops investigating for the optimal solution when one of three stopping criteria are met. Simulation Facility has a time limit of 10 minutes before it has to stop. The feasible solution that gives the highest social welfare will then be chosen as the final market clearing solution. The two other criteria are given by iteration limits and solution limits [19].

For the curious reader, a more in-depth explanation of the optimization method is given in the Euphemia public description [19].

[4] Power flows which floats from a low price area to a high price area

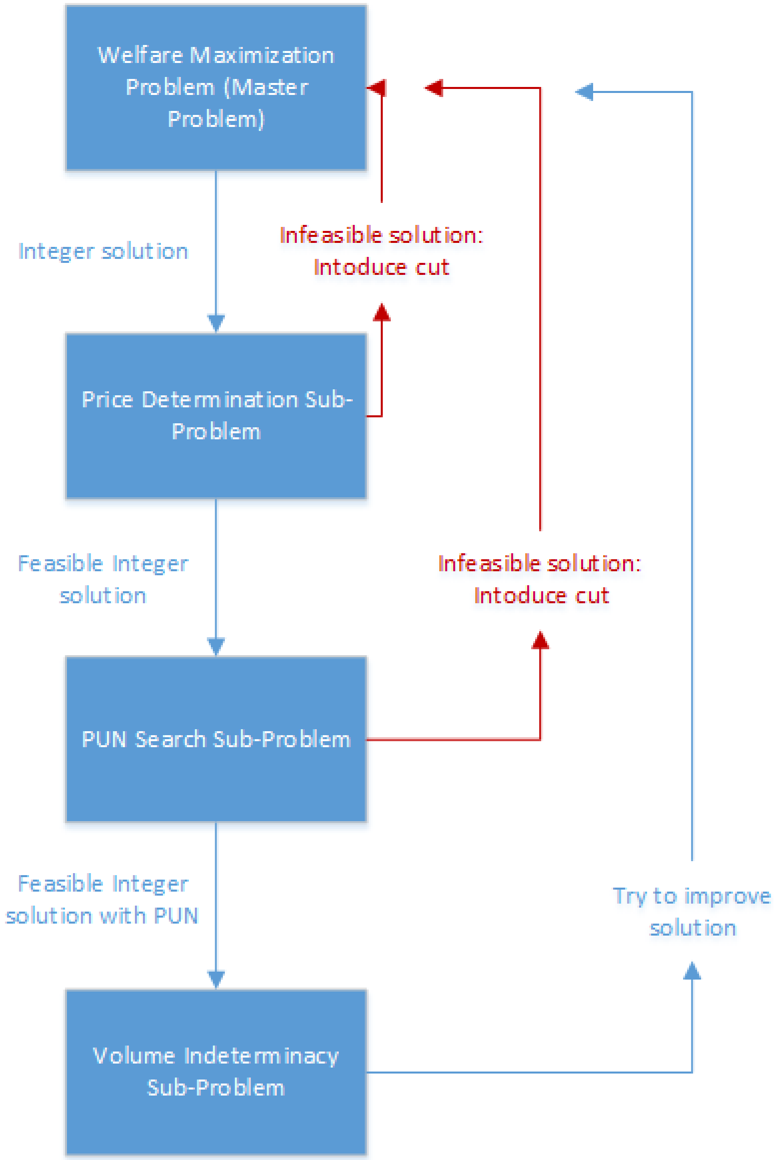

Figure 2.6: The stages of the euphemia optimization problem. The illustration is based on figure in [19].

3. Flow Based Market Clearing

Through the European Commission, ENTSO-E has developed a set of common network codes. The Network Code on Capacity Allocation & Congestion Managements guideline implies that FBMC is the preferred market design in the European Union. The guideline states that "the approach used in the common capacity calculation methodologies shall be a flow-based approach" [21]. This has to be followed unless the TSO can prove that the current model is more efficient then the flow based method. The intention of the European implementation of FBMC is to improve overall social welfare, guarantee security of supply, and promote market integration [2]. The FBMC method is therefore currently being evaluated by Statnett and the other Nordic TSOs.

As mentioned in Section 2.1.3 the current market clearing design, NTC, only considers commercial exchange between the market bidding zones. Since NTC does not account for physical limitations in the power network, actual power flows can differ from market power flows. For the flow based methodology however, the physical laws of the network are implemented as part of the optimization problem [22]. This denotes the main difference between NTC and FBMC approach. By implementing the flow based methodology one creates market solutions closer to the physical reality as well as keeping the operational security at a satisfactory level[2].

While using the FBMC approach the objective of the optimization problem is unchanged from the NTC method. The main difference for the two methods is found in the constraints of the problem formulation. This is illustrated in Table 3.1. The constraints limit the optimization problems solution domain, and by investigating the constraint differences one can demonstrate why FBMC can give a better utilization of the system.

This section will give a brief explanation of the FBMC approach, and illustrate the key role of the net positions while calculating the capacity allocations as a basis for the model. Deviations in the expected net positions can affect the coupling solution in several ways. If the expected net positions are clearly wrong, the linearizion of the flow based approach will be wrong. If this happens, the calculation basis for the method will be inaccurate. This can lead

	NTC formulation	***FB formulation***
Objective function	Maximize Social surplus	Maximize Social surplus
Subject to	$\sum NPs = 0$	$\sum NPs = 0$
	CTN constraint	FB constraints

Table 3.1: Table illustrating optimization problem for NTC and flow based approach. Based on table from [2]

to capacity allocations that are either too large or too small [23]. Fore example, if there is too little capacity allocated to the market the social welfare from trades can be reduced. If there is too much, the extra capacity might have to be specially regulated. Too much capacity can even lead too loss of system reliability [23].

3.1 The market coupling process in brief

The Flow Based Market Coupling process consists of three main parts; pre-market coupling, market coupling and post market coupling.

The pre-market coupling process starts at the evening two days before the physical production is distributed. During the pre-coupling face, the TSO calculates all system parameters that are needed for the actual market coupling. During this process the solution domain is also established. The parameters are later sent to and published at the Power Exchange [24].

The market coupling face is carried out by the Power Exchange, and is the actual solving of the market. The results, such as net positions and prices, are provided to the market. During the post-market coupling process the TSO verifies the market results, analyses the operational security and deals with the congestion income [2].

This section will further focus on the pre-market coupling process, since this part is the most relevant for the scope of the thesis.

For the rest of this report the letter "D" will be used as a reference to the operational day in question; D-1 represents the day prior to day D, D-2 denotes two day prior, and so on.

3.2 Pre-market coupling

In [2] the Nordic TSOs stat that the pre-market coupling process in general consists of six elements:

1. Creating a base case representing day D. The base case contains information on expected grid topology, expected net positions and flows on all critical network elements.
2. Define alls Generation Shift Keys (GSK), Critical Network Elements (CNE), corresponding outages and all remedial actions.
3. Define the Final Adjustment Value (FAV)
4. Verify the flow based parameters and solution domain.
5. Send all parameters to the Power Exchange.

3.2.1 Power Transfer Distribution Factors (PTDF)

The Transmission System Operator starts the capacity calculations two days before the physical production of electric power. At this stage, the TSO does not know the market bids related to production and consumption for day "D", and it is therefore difficult to predict the future state of the system. However, the TSO does know the physical properties of the power grid [2].

In FBMC approach the information about the physical properties is used to describe how the injection of one unit power in one node will be allocated across the power grid. This information is reflected in the sensitivity factors PTDFs. By including the PTDFs there are fewer limitations to the solution domain, and one obtains a better utilization of the system [2].

The PTDFs are derived from the AC power flow equations through a DC power flow representation of the power grid. A full explanation of the process is presented in [2]. The final equation derived from [2] for calculating the PTDFs is however illustrated in equation (3.1).

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}), \tag{3.1}$$

Where:
$PTDF$ = The PTDF value from node n to the line between nodes i and k.
B_{ik} = The susceptance between node i and k with a negative sign.
$Zbus_{in}$ = Element in in the systems impedance matrix.
$Zbus_{kn}$ = Element kn in the systems impedance matrix.

Figure 3.1 illustrates a three node example, and its corresponding line properties. The example is taken from [2].

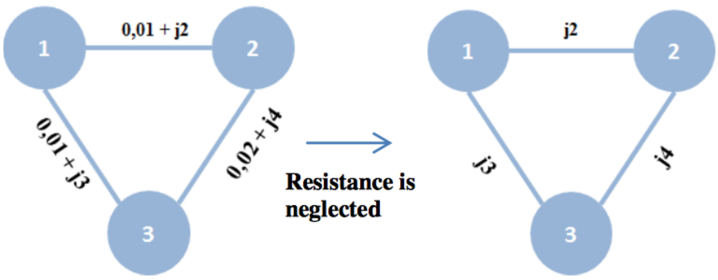

Figure 3.1: Example of a three node system, and its corresponding line properties. [2]

By constructing the $Zbus$ and using equation (3.1), the PTDF matrix can be found. The matrix fo this system is illustrated in equation (3.2).

$$PTDF = \begin{array}{c} \\ 1-2 \\ 1-3 \\ 2-3 \end{array} \begin{array}{c} \begin{array}{ccc} 1 & 2 & 3 \end{array} \\ \begin{pmatrix} 0.33 & -0.44 & 0 \\ 0.67 & 0.44 & 0 \\ 0.33 & 0.57 & 0 \end{pmatrix} \end{array} \tag{3.2}$$

The example illustrates that if one unit of power is injected in node 1, 33% will be distributed on line 1-2, 67% will be distributed on line 1-3, and 33% will be distributed on line 2-3. The knowledge of how the injected power is distributed in the system is one of the fundamental parameters used by the TSO wile calculating the flow based grid constraint. [24].

3.2.2 The solution domain

The flow based constraint derived from the PTDFs will always limit the flow based solution domain. However, with the NTC approach one uses the maximum capacity that can be exchanged commercially on a border in a given direction. By using the FBMC the concept of boarders disappears, and the physical properties reflected in the flow based parameters determines the solution domain. As a consequence the resulting solution domain from the FBMC approach is always larger or the same as the solution domain for the current NTC method.

Figure 3.2 illustrates the final solution domain for the three node example presented in Subsection 3.2.1. The figure illustrates the solution domain obtained with NTC and FBMC approach. Points 1 and 2 presents solutions that are not obtainable for the NTC method, but is possible with the flow based approach. The solution domain clearly shows that in theory the welfare benefit of using the FBMC approach compared to the NTC method.

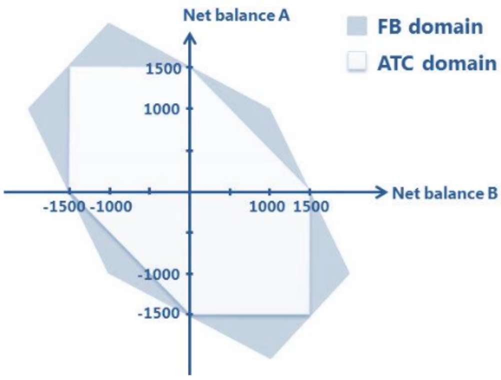

Figure 3.2: Illustration of the difference between ATC/NTC and FB market domain. Figure is collected from [2]

3.2.3 Critical Network Elements, Generation Shift Keys and Remaining Available Margin

Not all grid elements are of interest in the optimization model. Critical Network Elements (CNE) are of interest in the FBMC approach since they are elements that can potentially produce binding constraint to the optimization model. An example of a CNE is a line that could potentially overload. [8].

The Power Transfer Distribution Factors described in earlier sections are used when describing the CNEs in the optimization constraints. The described PTDFs are calculated at a nodal basis and works as node-to-CNE PTDF. The FBMC model relies however on zone-to-CNE Power Transfer Distribution Factor. Therefore, the calculated PTDFs have to be converted to fit the zone-to-CNE in the Flow Based Market Clearing model. This is done with a parameter called generation shift keys (GSK) [25].

As discussed in [2] the GSKs "describes how the net position of one node changes with the net position of the area it is a part of", and is a linear approximation of a non-linear relation. The method for constructing the GSK can differ, and there is still uncertainty related to which strategy is the best. In the master thesis "Flow Based Market Coupling" [8] Birgit Jegleim explains and examines several different GSK strategies for the Nordic system.

The Remaining Available Margin represents how much power that can be allocated on each CNE while keeping the system secure. The Remaining Available Margin can also be referred to as the "free margin" for each Critical Network Element [2]. The Remaining Available Margin (RAM) is expressed using equation (3.3) and equation (3.4). The equations are retrieved from [2].

$$RAM = F_{max} - FRAM - FAV - Fref' \tag{3.3}$$

$$Fref' = Fref - PTDF * NP^{BC} \tag{3.4}$$

where,
RAM = Remaining available margin
F_max = Maximum allowed flow on the CNE
Fref’ = Referance flow at zero net positions when using the computed PTDF matrix.
FRM = Flow reliability Margin
FAV = Final adjustment Value
Fref = loading of the CNEs in the base case given the net positions reflected in the base case.
NP^{BC} = Net position of all bidding zones in the base case.

As shown in the equations the RAM relies on the expected base case. The relation between flow, net position and the RAM is given as $PTDF * NP \geq RAM$. The relation is illustrated in Figure 3.3. A more thorough explanation of the Remaining Available Margin can be found in [2].

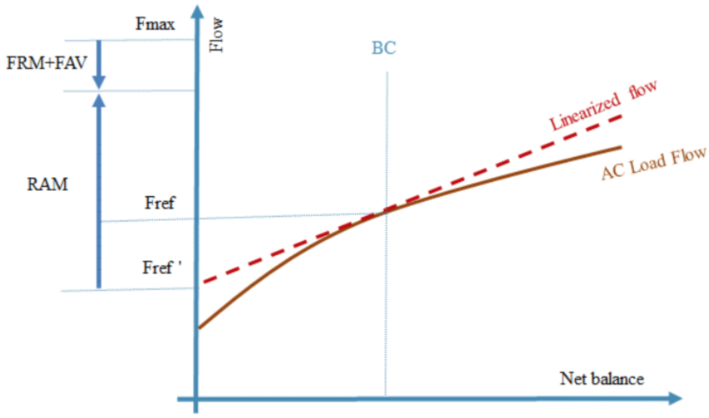

Figure 3.3: Relation between net position/balance, flow and RAM. Figure collected from [2]

This section shows how the expected net positions affects the calculated base case. As explained earlier, deviations in the expected net positions can affect the coupling solution in several ways. For example, the linearizion made in the flow based approach can be clearly wrong if the forecasted net positions have large deviations form the actual net positions - potentially reducing the system security.

4. Method

This chapter gives a description of how the estimation of net position simulations were carried out. This includes; Collecting and preparing the relevant input data, choosing correct system parameters and topology for the simulation in SF, and collecting the final results.

4.1 The main approach

This chapter gives a theoretic explanation of the estimation approach developed in this master thesis. The main objective of the tested estimation method is to give reasonable predictions of future net positions. This is done by combining already known market information and market forecasts.

As a part of the foundation for the estimation process it is assumed that the Day-ahead market curves mainly consists of two parts; One part represented by price dependent bids, and one part represented by non price dependent bids. Thus, the price depended bids are related to the inflexible part of the market curves, while the price independent market bids are related to the flexible part.

The estimation method further assumes that the inflexible part of the market curves is roughly the same from one day to the next, i.e. the flexible market bids on a given Wednesday are roughly the same as the flexible marked bids on the upcoming Thursday. This leads to the assumption that the price independent market bids, or the inflexible part of the market curves, changes according to different parameters from day to day. These changes will cause a parallel shift of the market curves. A simplified illustration of the market curves and the parallel shifts are presented in Figure 4.1.

The main idea of the estimation method is to identify the price independent market bids and use them in the estimation. The idea is to use the parallel shifts to change the market bids and further find the forecasted net positions. In this thesis these bids are mainly assumed to come from non-dispatchable generation, such as wind and run down river power, and consumption related to changes in temperature. This is further discussed in Section 4.4.

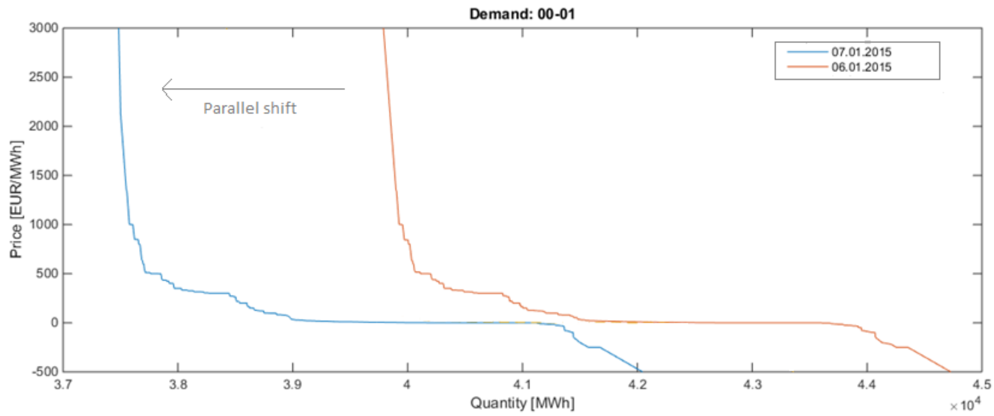

Figure 4.1: Illustration of aggregated demand curve from 06.01.2015 and 07.01.2015 during hour 00-01. The curves illustrates how the shape of the market curves are roughly the same, but there is a parallel shift form one day to the next. Data for the curves are collected from Nord Pool.

The day-to-day parallel shifts in the supply curve is in this thesis mainly assumes to be related to power production from renewable resources. This conclusion is mainly from the fact that the fuel cost related to this type of power production is zero, and the marginal production cost is therefore very low. Since the supply curve in the Day-ahead power market reflects the production units marginal cost, the power production from renewable resources will reflect the price independent market bids. In this research generation from run-down-river systems are not accounted for. This is because of limited available data.

The daily parallel shifts for the demand curve are mainly assumed to come from changes in temperature dependent consumption. These type of bids are mostly inflexible and will therefore cause a parallel shift of the demand curve from one day to the next.

Figure 4.2 illustrates a simple flow chart of the the approach developed to identify the inflexible market bids, and how the new approach constructs the new market curves. The figure shows how Day-ahead market curves from a given reference day is used as a bases for the estimation. These market curves are altered with parallel shifts calculated from expected changes in the demand and supply curves from reference day and the estimation day. By adding the expected market curve changes, the estimated market curves for the operational day is found.

The reference day model is altered by changing the amount of price insensitive bids for each demand and supply curve in every bidding area. The Elspot production and consumption for the reference day is known when the TSO starts the capacity calculations two days before the operational day. This is thus the most resent information about the reference day and is used as the forecast for that day. The forecast for production and consumption for the oper-

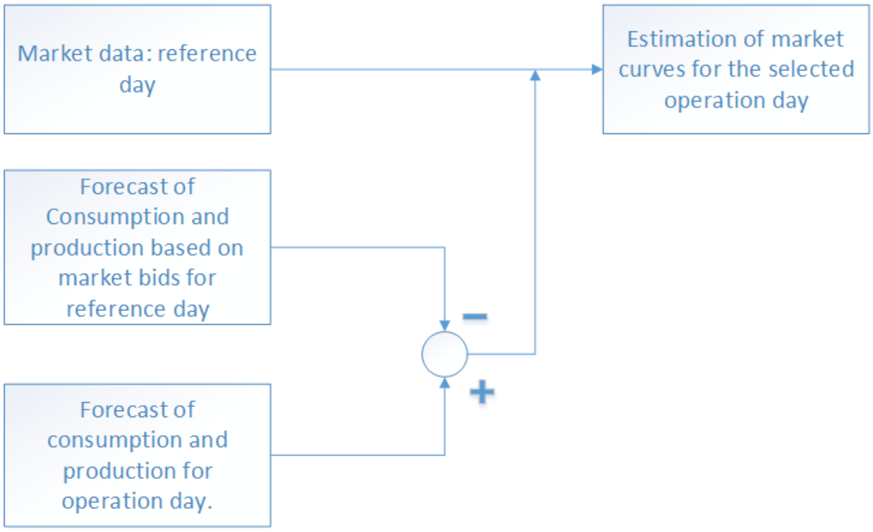

Figure 4.2: Flow chart illustrating the approach of finding the estimate of future market curves.

ational day is not known, and is therefore based on historical and statistical data. In order to calculate the supply and demand shift in each bidding area the Elspot production and consumption for the reference day is subtracted from the operational day forecasts. A MATLAB® script developed by the student collects data, and calculates the shifts in net positions for all Nordic bidding areas.

The new estimation is then found by adding the calculated shift to the available market data of the chosen reference day, and computing a new market clearing with the altered supply and demand curves. The new clearing is found by using the market clearing program "Simulation Facility".

4.2 Choosing the appropriate reference day

The reference day for each simulation was chosen according to Table 4.1. It was desirable to choose a day as close as possible to the operational day (also called day D). The TSO starts the capacity calculations at the evening of D-2, and therefore has sufficient information about the Day-ahead market curves for the next day. D-1 is therefore chosen as the preferred reference day for day D.

It is assumed that market curves during the weekend can have shapes deviating from the market curves during the weekdays. Therefore all Saturdays and Sundays use the previous weekend as reference days. Mondays use Fridays as the reference day, since this is the closes previous weekday before the weekend. The schedule is presented in Table 4.1.

Monday	*Tuesday*	*Wednesday*	*Thursday*	*Friday*	*Saturday*	*Sunday*
D-3	D-1	D-1	D-1	D-1	D-7	D-7

Table 4.1: Possible reference days used in the estimation approach. The letter D denotes the day of physical power production. The TSO starts the capacity calculations at D-2 days.

4.3 Altering market curves in Simulation Facility (SF)

There is no straight forward way to make parallel shifts to the demand and supply curve in SF, and a alternative approach had to be developed.

Adding extra block orders to the inflexible part of the market curves was early suggested as a possible method. To ensure that the orders were accepted the block orders were given the limit prices; -500 for sell orders and 3000 for buy orders. This method turned out to work well for shifts with positive quantities (increasing the amount of insensitive bids), but was not suitable for negative changes. Other methods for handling negative shift were therefore suggested. Three methods were seen as most relevant:

1. Adding negative shifts as positive block orders for the other market curve.
2. Deleting block orders using queries in SF.
3. Change prices of exciting block orders so they are forced in or out of merit.

The first solution has several benefits, but also causes some limitations to the simulation results. For instance, a shift of $-10MW$ to the supply curve is treated as a $10MW$ shift of the demand curve. This results in correct NPs for each area, but the quantities related to consumption and production are wrong. In order to get the correct quantities one would have to adjust the production and consumption quantities after the simulation. In reality, block bids have a minimum acceptable duration time of three hours [11], this could be a problem since the NPs shift are valid for only one hour. The Euphemia algorithm is not implemented with this restriction and SF allows one hour block orders.

The second suggestion uses a tool in SF called queries. The tool enables the user to make adjustments to the simulated batch. One of these adjustments is to delete block orders. The deleted block orders are specified by range of hours, sense (if it is a sell or buy block), quantity and price. This method poses several limitations, for instance one would have to manually add all negative block order shifts instead of adding them as one list to the system. For a larger simulation period this would be very time consuming. In addition, it is not known if a bid at the wanted quantity and price exists in the system or not. Since the specified information of all orders are highly secret, one would not have the possibility to check if these bids already exists in the system or not.

The third option has many similarities with the second, but instead of deleting orders the prices related to a given block is adjusted to the price limits. This will force the block to either be in or out of merit. The limitation of knowing the price is no longer an issue, but the quantity needs to be specified. As mentioned above this information is classified and therefore one does not have the possibility to know the quantities before the actual simulation.

The first method is used in this research. Even though the resulted production and consumption quantities are not correct, this method is a great deal less time consuming then the others. This is especially important with large simulations. In additions one does not face the limitation of explicitly knowing the market bids before the simulation.

4.4 Parameters affecting the day-to-day market changes

As described earlier, several factors were added to the model due to the effect they might have on the day-to-day market changes in the Nordic system. As explained earlier the added parameters includes:

- Inelastic demand
- Non-dispatchable generation
- Outages of network elements (changes in capacity).
- Topology

The inelastic demand is assumed to typical relate to changes in temperature. The non-dispatchable generation includes not only non-regulating renewable generation, but also changes in nuclear power production. The important factor is to identify generation that is not affected by changes in price. For this case, nuclear power production is therefore assumed to be non-dispatchable.

Several of these parameters were also implemented for the German region. The German parameters includes: wind power production, solar power production and inelastic demand. Inelastic demand was not originally a part of the model, but since the changes in supply can be quite large, it was seen as beneficial to add this parameter as well.

In addition to the consumption and generation, changes in topology and network elements were adjusted in the model. All system capacities were adjusted in order to fit the conditions during the operational day. In SF all transmission capacities have to be added manually for each connecting. There are many connections in the PCR region, and in order to reduce the amount of manual calculations a simplified topology of the region was used. This region only contains the northern part of Europe, including among other, German, Poland and France. Figure 4.3 shows an illustration of the simplified topology. This topology includes over 40 individual connections. Using a simplified topology might cause a limitation to the simulation results, but it is assumed that the impact of the rest of Europe is quite small and negligible.

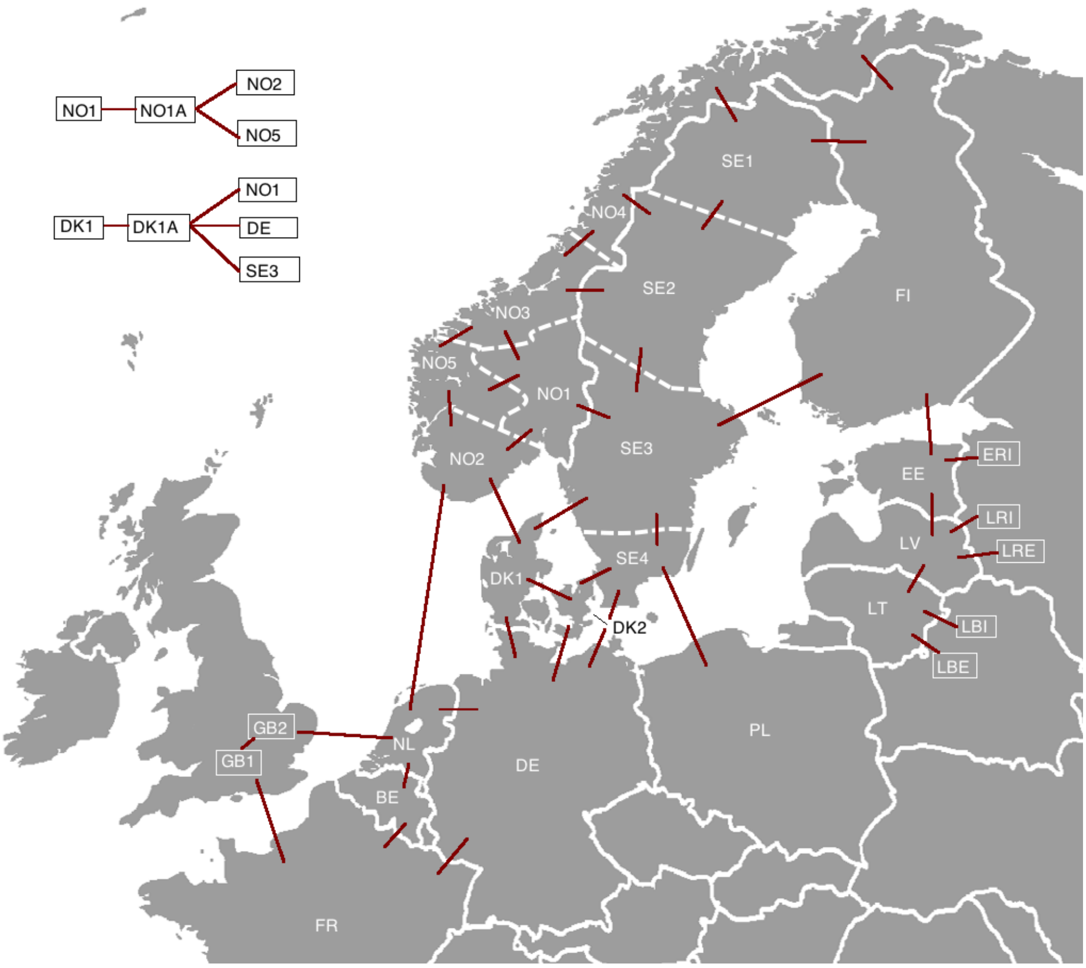

Figure 4.3: Illustratin of simplified topologi of the PCR region. The boxed squares illustrates areas that are either virtual or represents export/import. For example, LRI represents the Lithuanian-Russian Import, and LRE represents the Lithuanian-Russian export. NO1A and DK1A are virtual areas created to steer the import/export to NO1 and DK1 [26].

4.5 Collecting and modifying relevant source data

As mentioned in Section 4.1, one of the key elements of the studied estimation approach is the known market data and forecasts. The data set works as a foundation for the approach and it is therefore vital that the collected data is reliable and as correct as possible. In this thesis the year of 2015 has been studied, and all of the marked data is therefore already known. Net positions relates to market and not the physical clearing. Therefore, one wants to use prognosis and forecasts of consumption and production instead of actual physical data. In the extend that the data has been available, market prognoses have been used instead of actual power consumption and production. This is done in order to make the research as close to the reality as possible.

The Nordic wind power production and consumption data was mainly collected from Nord Pools database on historic market data. [1]. It was seen as desirable to collect as much data as possible from the same source, but some of the data was not available and had to be collected elsewhere. A specific overview of all collected data is given in the Appendix.

There is limited forecast data available for some of the studied bidding areas, and instead some actual measured data was used. For instance, due to the lack of dependable Norwegian wind power production data, measured production data was used instead. It is therefore assumed in this thesis that most of the Norwegian wind power production is traded on the Elspot market. The German wind power production was collected from the German TSOs [2]. The German data is given in 15 minutes intervals and was therefore aggregated to hourly values.

Elspot volumes from Nord Pool were used as a representation of the Nordic consumption. Due to the structure of the Elspot volume data, exchange on connections outside the Nordic and Baltic region are subtracted from the consumption data, e.g. flow on connections such as NorNed were subtracted from the Nord Pool values.

The assumptions related to use of measured data compared to forecasts can pose limitations to this study, and can therefore lead to uncertainties in the simulation results. If further investigation on the subject is desired, applying reliable forecasts and prognoses for all consumption and wind production data may give a more realistic results.

4.6 Handling public holidays in Simulation Facility

There is some difficulties of how public holidays should be handled when using this estimation approach. It is desirable to simulate as many days as possible, but at the same time keep the method efficient. For example, the amount of manual calculations should be kept at a minimum.

[1] http://www.nordpoolspot.com/historical-market-data/

[2] Germany has four transmission system operators; TenneT, Amprion, 50Hertz and Transnet BW.

It is assumed that the consumption pattern during one week changes during weekdays and weekends are different [27]. This will result in different market curve shapes for the given day. Therefore, when a weekend was simulated it was decided to use the market curves from previous weekend as a reference. Public holidays and other special days are assumed to have similar consumption patters to weekends and it would be reasonable to compare these days with the previous Sunday. Due to the nature of how a simulation is executed in SF in this study, this turned out to be very time consuming and cumbersome. One would have to construct new block orders and capacities files for all public holidays, and these would have to be implemented manually into the program. It was therefore decided to treat public holidays as normal days while the simulations were carried out. The simulation dates impacted by the public holidays were later removed from the results.

The issues related to public holidays and the lack of automation in SF clearly illustrates one of the programs weaknesses. If this program should be used for larger simulations executed on a daily basis it is important that most of the task can be automated.

It is however worth mentioning that if the method would be used on a daily basis, the simulation of public holidays would not cause the same problem. Each day would be estimated by itself and one could choose the wanted reference day without creating difficulties for the program. This is only an issue when doing simulations over er large period of time, as done in this thesis.

4.7 Collecting results

Before the analysis all simulations results were organized and adjusted. The different simulation results could then be compared later on.

After a simulation SF creates a folder containing all available information about the simulated sessions, e.g. information on block orders, market curves, PTDFs and line results. Due to privacy settings some of the information is highly classified and not available for the common user. However, most of the market data is available and can be used for further analysis.

A MATLAB® script developed by the student extracts the most relevant parameters and sorts them in a new Excel worksheet. Doing this with a MATLAB® script ensures that no data is lost or any mistakes are made while transferring the data to a new workspace.

The net positions for each bidding area for the Euphemia estimation, from the reference day and the actual net positions are seen as the most important indicators for the evaluation of the tested method. The report will therefore focus one these parameters. The MATLAB®

script also collects the size of the added block orders in the model. The main focus of the report are the Nordic bidding areas. All other bidding areas were therefore not evaluated any further.

4.7.1 Comparing the results

Two different methods were used in order to find relative values for the estimation results; one method presenting the mean absolute error as a fraction of maximum NTC, and one method presenting the mean absolute error as a fraction of the mean absolute flow. These indicators were also adjusted to represent values for the individual Nordic countries and the Nordic synchronous area. In order to separate the method easily they will further be referred to as method 1 and 2.

To give a reasonable illustration of the results the values were aggregated over larger periods and regions. The results were aggregated for each month of the year, in addition to each day of the week. For the aggregated areas the results were adjusted for each of the Nordic countries and the Nordic synchronous area.

While aggregating the results to larger regions the net positions for the aggregated region was found prior to the calculation of the absolute error. Figure 4.4 shows a small example of this approach. As seen, the new area AB is constructed by adding the net positions before further calculations.

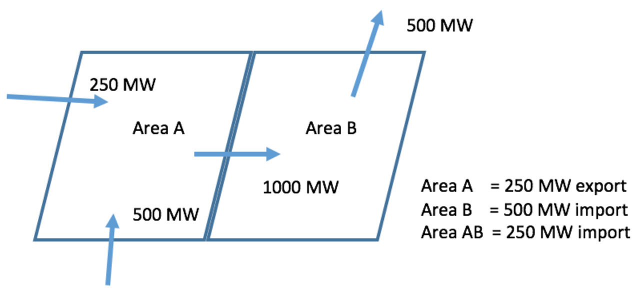

Figure 4.4: Illustratin of method used when aggregating bidding areas into larger regions. Area AB is seen as a new bidding area and the 1000 MW flow is "ignored".

MAE - Mean Absolute Error

The MAE for each hour and area was obtained by using equation (4.1) below. The notation corr. is shorted for correct.

$$MAE_{i,h} = \frac{1}{H}\sum_{h=1}^{H} \mid NP_{i,h}^{Euph} - NP_{i,h}^{corr} \mid, \qquad [MWh/h] \tag{4.1}$$

Where:
$MAE_{i,h}$ = Mean absolute error of net position for area i over number of hours H.
$NP_{i,h}^{est}$ = Euphemia estimated net position for area i and hour h.
$NP_{i,h}^{corr}$ = Correct net positions in area i and hour h.

Aggregated MAE values for larger regions were found with equation (4.2). The equation adds the net position of all aggregated areas within one hour before the absolute error is found.

$$MAE^{Agg} = \frac{1}{H}\sum_{h=1}^{H} \left| \sum_{i=1}^{I} NP_{i,h}^{Euph} - \sum_{i=1}^{I} NP_{i,h}^{corr} \right|, \qquad [MWh/h] \tag{4.2}$$

Where:
MAE = Aggregated mean absolute error of net position
$NP_{i,h}^{est}$ = Euphemia estimated net position for area i and hour h
$NP_{i,h}^{corr}$ = Correct net positions in area i and hour h
I = Total number of aggregated areas
H = Total number of aggregated hours

Method 1

The first method presents the MAEs as a fraction of the maximum flow during the simulation year. The advantage with this method is that all of the references are the same regardless of the market situation. The disadvantage however, is that the flows can be very large. This can give quite small percentage values for the results, hence making the results seem better then they actually are. Since the maximum flow is constant, the same formula could be used for the aggregated MAE. The weighted factor is found with equation (4.3).

$$MAE_{i,h}^{NTC} = \frac{MAE_{i,h}}{maxFlow_i}, \qquad [\%] \tag{4.3}$$

Where:
$MAE_{i,h}^{NTC}$ = Mean absolute error as a fraction of max flow for area i and hour h
$MAE_{i,h}$ = Mean absolute error of net position for area i and hour h
$MaxNTC_i$ = Max flow for area i

The maximum flows were found by aggregating the Elspot flow data from 2015 listed at Nord Pools database on historic market data. The flows were found for each Nordic bidding area, country, and for the Nordic synchronous area. Initially, it was desirable to use the maximum NTC as a weighting factor, but for some areas the physical maximum was far from the maximum NTC. This is because the majority of all bidding areas serves as a transit function as well as being an export/import area. [1]. Therefore, the maximum flow during 2015 for each area was found instead.

Table 4.2 shows the maximum flows chosen for this research. To get one value for the flow, either the import or export was chosen as the representative value. The maximum flow was chosen as the highest value between import and export for all areas. The only exception was for SE4 where the lowest value was chosen. This is because the flow in this region is often limited by the lowest flow value [28].

Area	**Max flow** [MWh/h]	**Country/ region**	**Max flow** [MWh/h]
DK1	2862	DK	3966
DK2	1890	FI	2977
FI	2977	NO	5602
NO1	6700	SE	5693
NO2	5066	Synch	5693
NO3	1887		
NO4	1700		
NO5	4400		
SE1	3451		
SE2	7000		
SE3	9532		
SE4	5200		

Table 4.2: Maximum flow in the Nordic region during 2015.

Method 2

The second method weights the mean absolute error as a fraction of the mean absolute flow. The fractions are found by combining equation (4.4) and equation (4.5). The power flows corresponding with the correct net positions for the simulated day were used as the mean absolute flows. These flows were chosen, as opposed to the Euphemia flows, so it would be easier to compare other results later on, i.e. comparing results from the reference day and Euphemia simulation.

$$MAF_{i,h} = \mid NP_{i,h}^{corr} \mid, \qquad [MWh/h] \tag{4.4}$$

Where:
$MAF_{i,h}$ = Mean absolute flow for area i and hour h
$NP_{i,h}$ = Correct net positions in area i and hour h

$$MAE^{flow} = \frac{MAE_{i,h}}{MAF_{i,h}}, \qquad [\%] \tag{4.5}$$

Where:
$MAE_{i,h}^{flow}$ = Mean absolute error as a fraction of mean absolute flow for area i and hour h
$MAE_{i,h}$ = Mean absolute error of net position for area i and hour h
MAF_i = Mean absolute flow for area i and hour h

The aggregated values for the mean absolute flow over several hours and areas were found with equation (4.6).

$$MAE^{agg} = \frac{1}{H}\sum_{h=1}^{H}\left|\sum_{i=1}^{I} NP_{i,h}^{corr}\right|, \qquad [MWh/h] \tag{4.6}$$

Where:
MAF^{agg} = Aggregated mean absolute error of net position
$NP_{i,h}^{corr}$ = Correct net positions in area i and hour h
I = Total number of aggregated areas
H = Total number of aggregated hours

Finally, by combining equation (4.6) and equation (4.2) the aggregated values for method 2 could be found as illustrated in equation

$$MAE = \frac{MAE^{agg}}{MAF^{agg}}, \qquad [\%] \tag{4.7}$$

Where:

MAE^{agg} = Aggregated mean absolute error of net position
MAF^{agg} = Correct net positions in area i and hour h

Due to the potential lower values of the mean absolute flows compared to the maximum flow, the second method can give a clearer presentation of the simulation results. As explained earlier, the maximum flow is in rarely met and the absolute flows might be seen as more realistic reference. The drawback of this method is that the references values will in some extended change when one is comparing different time periods. In addition, some illustrated results can seem very large even though the MAE is not significant large, but instead because the flow is very small. This has been tried to avoid by using mean absolute flows, but there is still a change that this problem might occur, especially when evaluating small time periods.

The density functions

As a part of the evaluation the errors for each bidding area was plotted as density functions using the Kernel Smoothing function in MATLAB®. The function generates a probability density estimate of the sample data. The errors were evaluated with 500 equal spaces points. The kernel distribution is typically used when one does not want to make assumption regarding what type of distribution a data set represents.

Further, the density functions for the Euphemia estimation were assumed to represent a normal distribution. The mean and 90% interval was therefore found for each bidding areas. This was done in order to give a more clear illustration of how the size of the errors, as "reducing large errors is seen as more important then minimizing the average"[1].

Figure 4.5 gives an illustration of a normal distribution and the 90% interval. As seen from the figure, 90% of the values are within the interval between X1 and X2. Therefore, 10%, the largest errors, would lie outside these values.

Figure 4.5: Illustration of a normal distribution and the 90% interval

.

5. Case study

This chapter gives an explanation of the cases studied in this masters thesis. There are primary two main studies for 2015 presented in this report; One where the applied data source is as up-to-date as possible, and one where the applied data source is two weeks old. The purpose of this chapter is to give the reader an understanding of the bases for each simulation case.

First the chapter gives a general description of the Nordic power system during 2015 with a focus on the factors used in this thesis. For example, wind power production and inelastic consumption.

5.1 A brief observation of the Nordic power system during 2015

This section gives a short description of the Nordic power system during 2015. The purpose is to give the reader an overview of the system state and the main trends during the selected simulation year.

2015 was in general a year with milder weather then usual and higher water inflow then usual. There was also in general a high wind power production, a combination which lead to historic low power prices. As a result, 2015 had an increase of power production throughout the year, and the Nordic region was primary a net export area. [29].

Figure 5.1 illustrate the Nordic combination of electrical power production. Hydro power stood for over half of the total production, while wind and nuclear power stood for 9% and 30% respectively. Most of the hydro power production units can be regulated and is therefore a key player for the balancing of the market. The Nuclear power production in Sweden and Finland serves as an important base lowed for the Nordic system, and is placed in areas with large demand [30].

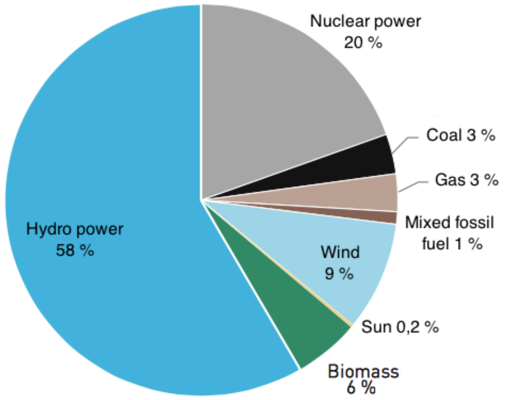

Figure 5.1: The Nordic composition of power production in 2015. The figure is translated and collected from [30]

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Wind and nuclear power production

Figure 5.2 illustrate the Nordic wind power production during 2015. The figure shows that there was in general a high production of wind power during 2015, especially throughout the winter months. The Nordic wind power production have been significantly increased the past couple of years. This can mainly be explained by the large Swedish investments in the wind power sector [29]. In 2015 installed capacity for Swedish wind power production was at 5,4 GW, which corresponds to 8 % of total installed capacity. The installed capacity in Denmark was 4,9 GW, corresponding to 40% of the total installed capacity [29].

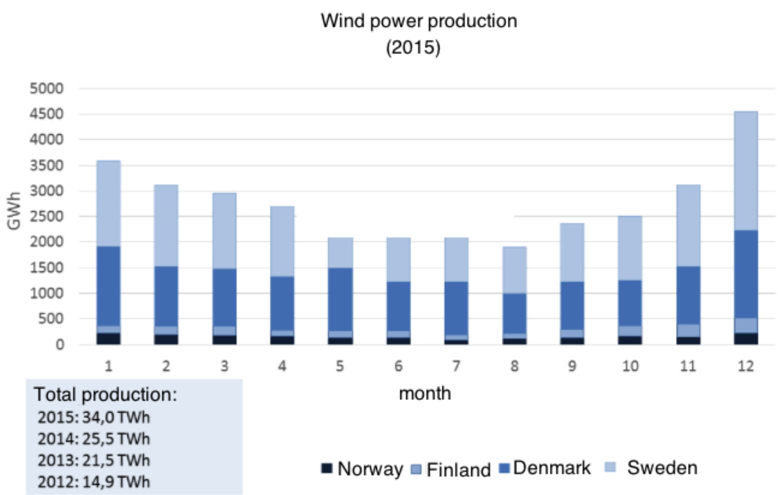


Figure 5.2: Nordic wind power production during 2015. Figure is collected from and based on figure in [29]

Figure 5.3 presents the Swedish and Finnish nuclear power production throughout 2014 and 2015. By examining the figure, one can see that the Swedish production was in general lower then the previous year. The low production was primary due to competition from wind and hydro power production. As seen in Figure 5.3 Sweden down regulates the nuclear power production in May. In [29], NVE states that this was primary because of very low power prices during the snow melting season [29], resulting in large production of hydro power.

The Finnish nuclear power production had some miner periods with maintenance during 2015, but the level of production was mainly at the capacity limit, and similar to the 2014 level.

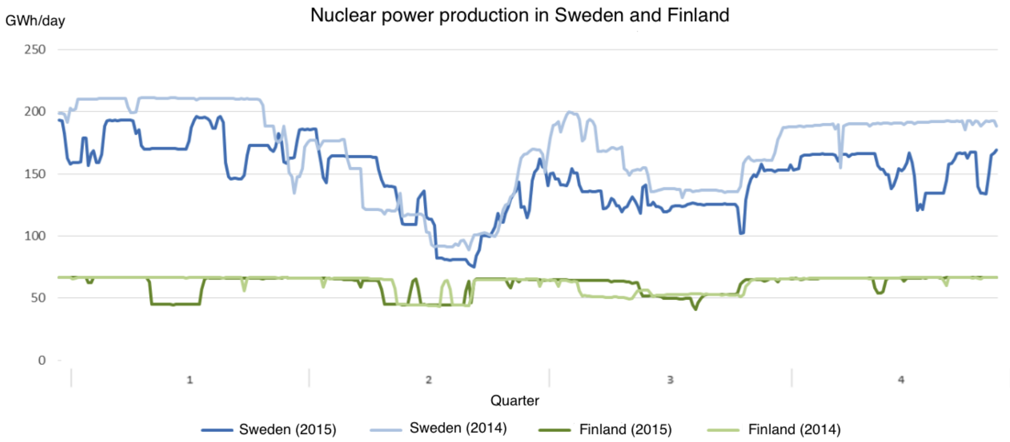


Figure 5.3: Nuclear power production in Finland and Sweden during 2015 and 2014. Figure is collected from and based on figure in [29].

Topology

Figure 5.4 gives an overview of the main changes in the European electrical system topology during 2015. On January 9th a virtual area NO1A was introduced. NO1A was implemented to make it easier to control the import/export in and out of NO1, without reducing the capacity on lines NO2 - NO1 and NO5 - NO1 [31]. Area PLA serves the same purpose for PL as NO1A does for NO1.

		Areas		Lines	
Date	Event	Added	Removed	Added	Removed
09.01.15	NO1A intro	NO1A		NO1A - NO1	NO2 NO1
				NO2 - NO1A	NO5 - NO1
				NO5 - NO1A	
24.02.15	Expantion Italy				
20.05.15	Flow based intro in CWE				
01.06.15	FRE intro	FRE		FI - FRE	
18.11.15	Loss factor NordNed				
24.11.15	PLA intro	PLA		PL - PLA	SE4 - PL
	Trade on LitPol and NordBalt			SE4 - PLA	
				LT - PLA	
				SE4 - LT	

Figure 5.4: Table of selected events in the Euphemia Topology during 2015.

Due to the chosen simplified topology in SF several of these changes do not affect the simulations in this study. The implementation of FBMC in the CWE region is accounted for, and has probably the most effect on the system, for example by improving the capacity allocation at the Power Exchange [3]. The simplified grid only consist of the northern part of Europe, and the implementation of the Italian market is therefore not reflected in the simulation. Another introduced area that is not implemented is FRE. It is important to note that these simplifications might limit the simulation results, however the objective of the project is to research in general how well the estimation approach works in general, and it was therefore seen as a reasonable simplification.

Transmission capacity

Figure 5.5 illustrates the available transmission capacity during 2015. As seen from the figure, there was a reasonable good availability of transmission system capacity during 2015, the exceptions are however: DK1 - DE, SE4 - DE and NO4 - SE1. The reduction in transmission capacity on the German connections are mainly caused by large wind power production and internal congestions in Germany. The reduction for the NO4 - SE1 connection was caused by frequency maintenance.. The total average transmission capacity for this connection was approximately half of the installed capacity. [29].

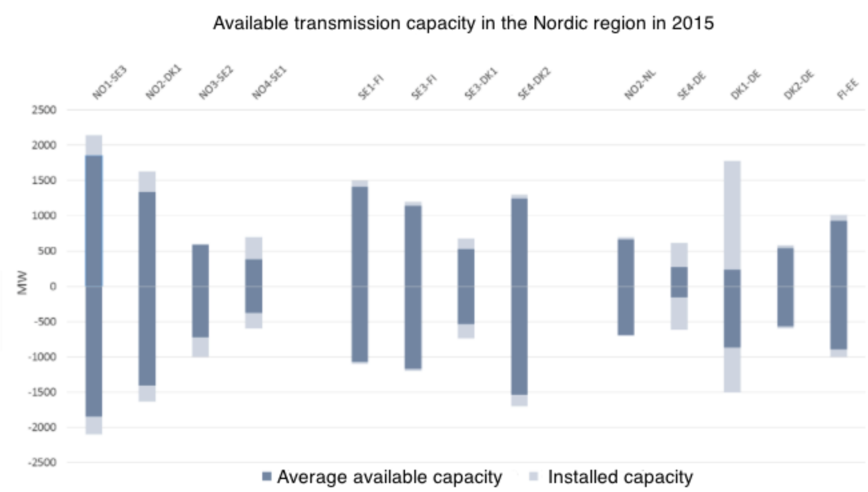


Figure 5.5: Available transmission capacity during 2015 in the Nordic system. Figure is collected from [29].

5.2 Case1: 2015 with up-to-date data

The first and main case evaluated in this research was what is called "the 2015 simulation" in this report.The simulation was carried out between January 19th 2015 and November 22th 2015. Since one of the main objectives of the thesis is to evaluate how well the developed estimation approach is. Therefore, the foundation of the case was chosen to be as good as possible. The reference day for each simulation date was therefore chosen to be as close as possible to the operational day. A reference days were chosen according to Table 4.1 illustrated in Section 4.2.

Case 1 was simulated with two different topologies. The first period was between January 19th and the FBMC launch in the CWE countries. The second period was simulated as a hybrid model combining FBMC in the CWE countries, and the NTC model for the other countries.

This section will highlight the main adjustments and parameters for simulation case 1. Most of the factors presented are illustrated in terms of the difference between operational day and the given reference day. This is to give an indication of the size of the parallel shifts added to the market curves.

The figures in this section presents the market shifts as mean values for the given month and not relative values. This is important to keep in mind while evaluating the figures. The relative size of the bidding areas can differ and 100 MW in SE3 has a different impact on that area compared to 1000MW in NO5.

Wind power production

Figure 5.6 illustrates the mean absolute difference in wind power production for each month during the simulation. Each bar gives an indication of the total added average shifts in the systems market curves. The light blue line gives the overall aggregated Nordic changes for each month. As seen from the figure the changes in wind power production are fairly even throughout the year, meaning that there were no significant larger day-to-day changes in wind power production during winter or summer in 2015.

The figure shows that the largest changes throughout the simulation year was mainly dominated by DK1, followed by SE3 and SE4. This seems reasonable, since DK1, SE3 and SE4 are areas containing large shares of wind power production.

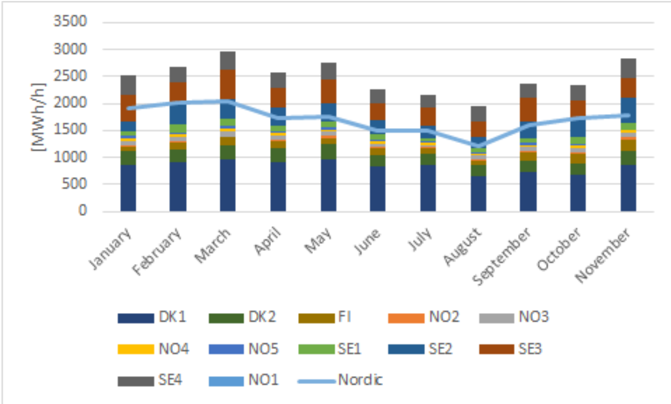


Figure 5.6: Absolute Average difference in wind power production between operation day and reference day for all Nordic bidding areas. Figure gives an illustrates for values between 19.01.2015 and 24.11.2015.

Consumption

Figure 5.7 shows the mean absolute difference between operational day and reference day for the Nordic consumption. The absolute mean change is calculated for each month during 2015. The blue line illustrates the aggregated Nordic values. The figures clearly show a seasonal difference for the consumption changes, indicating that there were large differences between operational day and reference day during the winter months. The largest mean absolute changes during the 2015 simulation mainly origin from areas SE3, FI, DK1 and NO1.

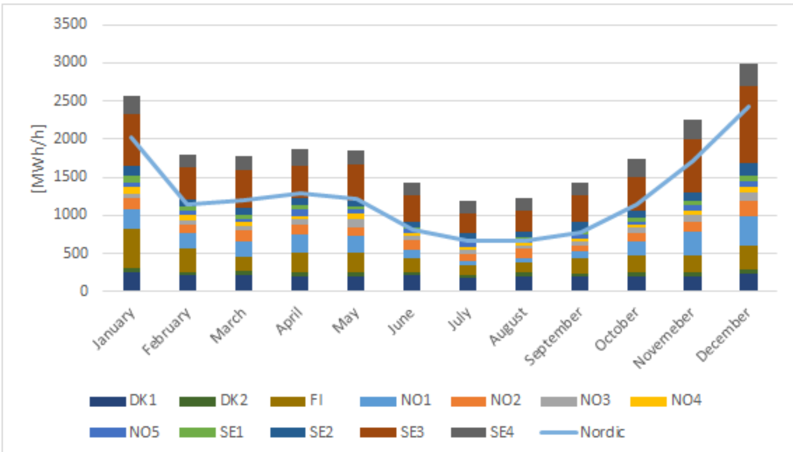


Figure 5.7: Mean absolute difference in wind power production between operation day and reference day for all Nordic bidding areas. Figure gives an illustrates for values between 19.01.2015 and 24.11.2015.

Nuclear power production

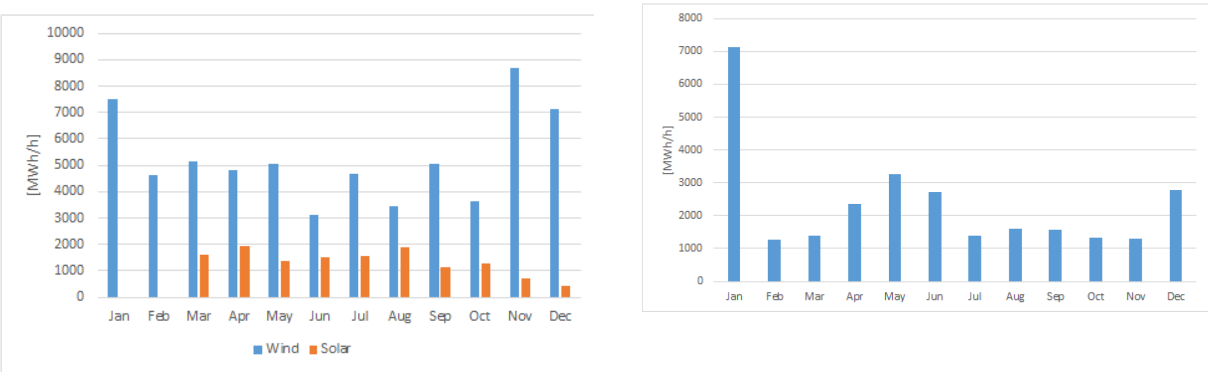
Figure 5.8 illustrate the day-to-day nuclear power production changes during 2015 for FI and SE3 respectably. The figures clearly show that the effect of changes in nuclear power can be significant for certain hours and days. By comparing the two figures one can see that the day-to-day changes are more frequent in SE3 then FI. The figures also show that the largest changes in terms of MWh/h occurs in SE3.

Figure 5.8: Difference in wind power production between operation day and reference day for all Nordic bidding areas. Figure gives an illustrates for values between 19.01.2015 and 24.11.2015. The very large delta for SE3 between March and April is found to be an error in the data set, and is neglected form the evaluation.

Germany

Figure 5.9a and 5.9b represents the mean absolute changes for the German market each month during 2015. Figure 5.9a shows the changes for the wind power production and solar production during the 2015 simulation. Due to limited data for solar production early in 2015, there are no values before March. This is however assumed to be a period with low solar production, and the values are seen to be zero in this research.

Figure 5.9b illustrates the changes for the German consumption. The figure shows a very large changes in January, but more similar values throughout the year. This large difference compared the other month indicate that this might be an error is the data source for the German consumption. It is important to keep this in mind while evaluating the simulation results.



(a) Renewable generation (b) Consumption

Figure 5.9: Difference in German consumption and renewable generation, between operation day and reference day for all Nordic bidding areas. Figure gives an illustrates for values between 19.01.2015 and 24.11.2015.

Simulated dates

Table 5.1 shows all dates that were removed from the simulation. Since all days acts as a reference day for another date, multiple dates had to be removed if there was something wrong with the data for one specific date. All public holidays and connected reference day was removed from the simulation. SF and many of the data sources treats the transition between summer and winter time differently. This caused periods with missing data, and it was decided to remove these dates from the simulation.

There was a bug in SF when the results were simulated, and the program was therefore not able to simulate some of the wanted dates. These were also taken out of the simulation.

Date	**Reference day for**	**Description**
2015.03.29	2015.04.05	Missing data and changing to summer time
2015.04.02	2015.04.03	Public holiday
2015.04.03	2015.04.06	Public holiday
2015.04.06	2015.04.07	Public holiday
2015.05.01	2015.05.04	Public holiday
2015.05.14	2015.05.15	Public holiday
2015.05.25	2015.05.26	Public holiday
2015.07.07		Was not able to simulate due to bug in system
2015.10.16		Was not able to simulate due to bug in system
2015.10.25	2015.11.01	Changing to winter time

Table 5.1: Illustration of dates that are taken out of the results. The column comment gives a description for each selected date. The reference days are also extracted from the results.

5.3 Case 2: 2015 with two weeks old data

Case 2 was tested over a period of seven weeks. This was from 25th of May until the 12th of July. During this period the FBMC approach was implemented in the Central Western Countries and the simulation was executed with a hybrid topology.

The same data was as for case 1 was used for case 2, except that the reference day was two weeks prior to the date used in case1.

Table 5.2 shows the dates that were taken out of the simulation du to public holidays and similar results.

Date	**Reference day for**	**Description**
2015.05.14	2015.05.29	Public holiday
2015.05.25	2015.06.09	Public holiday

Table 5.2: Table illustrating dates that were taken out of the simulation result.

6. Discussion of simulation Results

The purpose of this chapter is to present the main results and give a clear discussion of the findings. The discussion starts with an evaluation of the first simulation case described in Section 5.2. First, the results for case 1 are discussed in Section 6.1. Further, there is a more in depth study of large errors in Section 6.1.3. The simulation results are as well compared with an alternative estimation approach in Subsection 6.1.4. Section 6.2 presents and evaluates the results of the second case described in Section 5.3. The focus of this chapter are the main trends and the reliability of the simulation results.

It was later found that two values in the data foundation for SE3 that was clearly wrong. The error is during the March month. The data error leads to unrealistically large shift for the market curves, and therefore very large errors in the simulation. The error was discovered after the results were calculated, and will therefore affect the aggregated values presented in this report. It is important to keep this in mind while evaluating the presented results.

6.1 Case 1: 2015 with up-to-date data

The main object of the research is to get a reasonable indication of how effective the developed estimation approach is. It was therefore desired to test the method over a longer period of time, and 2015 was chosen as an appropriate simulation year.

The shift parameters included in the 2015 estimation are:

- Inelastic demand
- Non-controllable generation
- Nordic nuclear power production
- System topology

The 2015 simulation is evaluated by comparing the results from the Euphemia simulation and the results one would obtain by using the net positions for the given reference day, see Section 4.2. This way of presenting the results provides several benefits; The Euphemia estimations are compared with another possible net position approach (using the reference day values), and one is able to quantify how much the estimation has improved after adding the chosen market parameters.

The net positions are evaluated by bidding area, country and synchronous area. The results per area are also aggregated on a monthly bases, and for the year as a total. Finally, values for each weekday are studied.

The 2015 simulation starts at January 19^{th} and ends on November 22^{th}. The shorter simulation year is due to limited available data. Aggregated values for January and November are therefore not complete, but they are illustrated in the same way as the other months in the results. The presented yearly values represents the period between January 19th and November 22th.

6.1.1 Results per country and synchronous area

Figure 6.1a and Figure 6.1b illustrate the MAE for each Nordic country and the Nordic synchronous area. The red and green numbers indicate the months with the largest and smallest error for each country during the simulated year.

	Euphemia values MAE [MWh/h]				
	DK	FI	NO	SE	Synch
January	274	265	593	510	476
February	400	229	669	589	622
March	336	170	517	476	450
April	305	270	546	542	562
May	264	242	544	472	311
June	264	242	544	472	311
July	222	124	477	460	264
August	196	167	584	609	293
September	229	171	275	323	282
October	234	212	602	621	330
November	344	159	593	462	596
Yearly	278	201	539	512	415

(a) Euphemia simulation

	Referance day MAE [MWh/h]				
	DK	FI	NO	SE	Synch
January	875	250	1396	649	1309
February	882	370	1331	727	1230
March	829	274	1429	807	1372
April	973	192	1226	823	1397
May	1004	314	1317	949	1437
June	912	289	1164	631	988
July	883	181	1082	666	1075
August	815	253	891	991	1122
September	765	319	853	699	1005
October	758	286	1379	986	1055
November	875	246	1304	917	1221
Yearly	866	272	1198	808	1187

(b) Reference day values

Figure 6.1: Illustration of the simulation results as a fraction of mean absolute flow. The results are aggregated for each Nordic country and the Nordic synchronous area.

The figures clearly indicate that the largest improvement in terms of monthly MAE values were in Norway and Denmark. The improvement for the largest error in Norway was by 57%, and the overall best result had an improvement of 67%. The same type of improvement can clearly be seen in Denmark where the the largest error went from 1004 MWh/h to 400 MWh/h, an improvement of nearly 60%.

Sweden had a more moderate improvement compared to Norway and Denmark. Finland has the least improvement compared to the other Nordic countries, however the reference day errors are considerable lower than the others. This might indicate that Finland has smaller day-to-day changes in the market curves compared to the other countries. Some months, e.g. April has an increase of MAE while using the Euphemia estimation instead of the reference day value. There is an overall yearly improvement for all of the Nordic countries. The largest improvements are for Norway and Denmark.

The Nordic synchronous area has a significant improvement for all of the researched months. The yearly MAE decreases from 1187 MWh/h to 415 MWh/h, an improvement of 772 MWh/h. It is interesting to see that the yearly aggregated value for the synchronous area is lower then the same values for Norway and Sweden. The calculations were checked, and seems to be correct. One reason for this might be that there are internal net positions errors between the Nordic countries, that is not reflected when the values are aggregated for the synchronous area and new "area boarders" are established.

The large internal Nordic improvement might suggest that many of the day-to-day changes in the Nordic region comes from internal alterations in the market. In order to verify this suggestion one could study several simulated single hours. This has not been verified in this study, but is nevertheless mentioned as one possible explanation. It is also important to remember that the German parameters are added in the simulation, and might also have an impact on the Nordic results.

The MAE values are not weighted for the size of each area, e.g. amount of production and consumption. In order to more easily compare the relative improvements the results were normalized. The relative results are further discussed below.

MAE as a fraction of mean absolute flow

Figure 6.2a and Figure 6.2b illustrates the MAE for each Nordic country as a fraction of the mean absolute flow. The mean absolute flows are calculated separately for each month separately and can therefore slightly differ. This is important to keep this in mind while evaluating the figures. Figure 6.2a shows the results from the Euphemia estimation and Figure 6.2b presents the same values from the reference day. The scaling of the MAE gives a more clear impression of the relative results for each country.

The coloring scale is set to a maximum of 50 %. The scale is mainly set to this value in order to give a clear separation of the results, but a MAE larger then 50 % of the mean absolute flow between to areas can be seen as quite high. It is important to find an estimation approach that sorts out and reduces large single errors as well as reducing the total error. A single large error can for example be a major risk for the system security regardless of the total system error.

	Euphemia values - Percent of MA flow				
	DK	FI	NO	SE	Synch
January	35 %	13 %	20 %	35 %	22 %
February	34 %	17 %	29 %	19 %	23 %
March	44 %	17 %	30 %	24 %	26 %
April	36 %	13 %	29 %	16 %	20 %
May	37 %	19 %	25 %	23 %	29 %
June	20 %	18 %	20 %	17 %	9 %
July	16 %	7 %	25 %	11 %	8 %
August	12 %	8 %	24 %	17 %	10 %
September	14 %	10 %	9 %	16 %	12 %
October	17 %	15 %	27 %	18 %	10 %
November	29 %	9 %	21 %	22 %	25 %
Yearly	23 %	13 %	23 %	18 %	16 %

50 %
25 %
0 %

(a) Euphemia simulation

	Referance day - Percent of MA flow				
	DK	FI	NO	SE	Synch
January	103 %	16 %	48 %	38 %	53 %
February	108 %	23 %	65 %	27 %	59 %
March	92 %	20 %	64 %	32 %	57 %
April	103 %	14 %	69 %	27 %	62 %
May	120 %	22 %	60 %	39 %	74 %
June	70 %	22 %	43 %	23 %	30 %
July	63 %	10 %	56 %	16 %	33 %
August	49 %	13 %	37 %	28 %	37 %
September	48 %	19 %	29 %	36 %	42 %
October	54 %	20 %	61 %	29 %	33 %
November	74 %	14 %	46 %	45 %	50 %
Yearly	72 %	17 %	51 %	29 %	45 %

50 %
25 %
0 %

(b) Reference day values

Figure 6.2: Illustration of the monthly simulation results as a fraction of mean absolute flow. The results are aggregated for each Nordic country and the Nordic synchronous area.

The figures presents an overall yearly improvement for all countries, especially for Denmark and Norway. The largest improvements are in the first five months of the simulation, but several of the remaining month also experience a significant improvement compared to the results obtained from the reference day. May and February has an improvement of 84 percent points and 75 percent points in Denmark respectively. There is limited wind power production in the Norwegian bidding areas, and the available production capacity in the country mainly consists of easily regulated hydro power units. These areas would typically compensate for sudden changes in the system, and it is therefore reasonable to assume that if one of the other Nordic areas have changes from on day to the next some of the Norwegian bidding areas will compensate for the change in the system, and hence also experience large errors. As described in Section 5.1 2015 was a good hydrological year and there would be good access to cheap and easily regulated hydro power.

Figure 6.3 illustrates the yearly results from Figure 6.2a and Figure 6.2b in a graph. The picture shows the same trend as seen earlier, where the largest relative improvement is in Denmark.

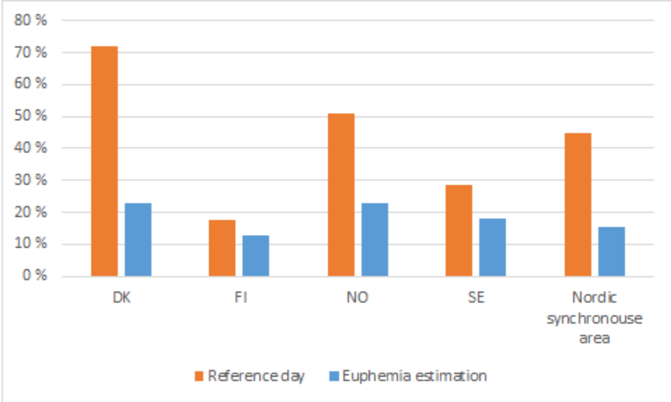


Figure 6.3: Plot of the mean absolute error as a fraction of the mean absolute flow for the aggregated yearly values.

MAE as a fraction of maximum flow

Figure 6.4a and Figure 6.4b presents the MAE as a fraction of the maximum flow. The values for the maximum flow are not presented here, but can be found in Appendix A.2. The results presented in the figures are fairly similar to the tables presented in Figure 6.2 earlier in this section, and illustrates the same main trends, i.e. large improvements in Denmark and Norway.

	Euphemia values - Percent of max flow				
	DK	FI	NO	SE	Synch
January	7 %	7 %	10 %	8 %	10 %
February	7 %	9 %	11 %	7 %	8 %
March	10 %	8 %	12 %	8 %	11 %
April	8 %	6 %	9 %	7 %	8 %
May	8 %	9 %	10 %	8 %	10 %
June	7 %	8 %	10 %	7 %	5 %
July	6 %	4 %	9 %	7 %	4,6 %
August	5 %	6 %	10 %	9 %	5,1 %
September	6 %	6 %	5 %	5 %	5 %
October	6 %	7 %	11 %	9 %	6 %
November	9 %	5 %	11 %	7 %	10 %
Yearly	7 %	7 %	10 %	7 %	7 %

25 %
12,5 %
0 %

(a) Euphemia simulation

	Referance day - Percent of max flow				
	DK	FI	NO	SE	Synch
January	22 %	8 %	25 %	9 %	23 %
February	22 %	12 %	24 %	10 %	22 %
March	21 %	9 %	26 %	11 %	24 %
April	25 %	6 %	22 %	12 %	25 %
May	25 %	11 %	24 %	13 %	25 %
June	23 %	10 %	21 %	9 %	17 %
July	22 %	6 %	19 %	9 %	18,9 %
August	21 %	8 %	16 %	14 %	19,7 %
September	19 %	11 %	15 %	10 %	18 %
October	19 %	10 %	25 %	14 %	19 %
November	22 %	8 %	23 %	13 %	21 %
Yearly	22 %	9 %	21 %	11 %	21 %

25 %
12,5 %
0 %

(b) Reference day values

Figure 6.4: Illustration of the monthly simulation results as a fraction of maximum flow. The results are aggregated for each Nordic country and the Nordic synchronous area.

The improvement is similar for all months during the year, indicating that the estimation method does not work better for some months compared to others. Figure 6.5 shows the yearly results as a fraction of the maximum flow in a bar chart.

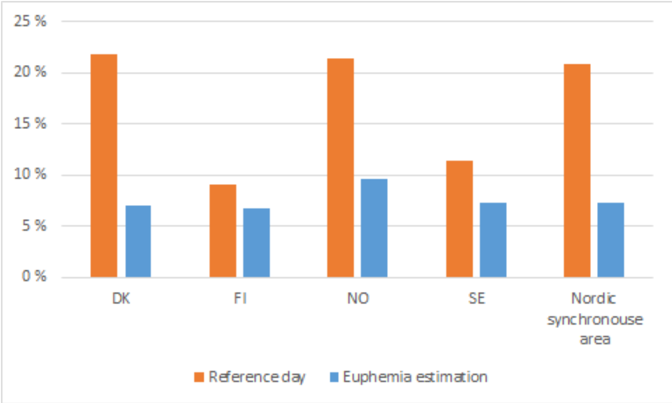


Figure 6.5: Plot of the mean absolute error as a fraction of the mean absolute flow for the aggregated yearly values.

6.1.2 Results per bidding area

Figure 6.6 compares the MAE for each Nordic bidding area during 2015 for the Euphemia estimation and the reference day method. In Figure 6.6 the yearly values for DK1, and NO2 stands out as the areas with the largest starting point errors, closely followed by SE3. After the implementation of the market parameters all areas, except for NO2 and SE3, have a MAE below 300 MWh/h. A more detailed illustration can be found in Appendix A.3.2.

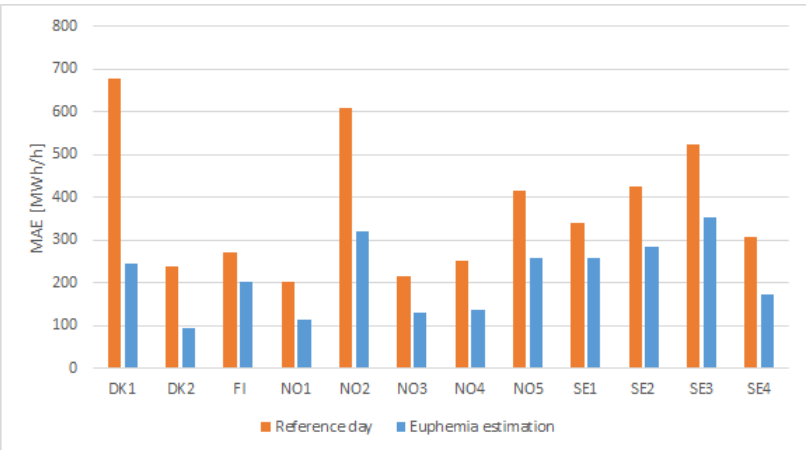


Figure 6.6: Plot of the mean absolute error for each Nordic bidding area during the simulated year. The graph compares the Euphemia estimate with the reference day values.

MAE as a fraction of mean absolute flow

Figure 6.7 and 6.8 presents the MAE as a fraction of the mean absolute flow for each Nordic bidding area. Similar to the MAEs values evaluated in the previous section, DK1 and SE3 stands out as an area with large errors for the reference day case. When the MAE is compared with the mean absolute flow, NO4 seems to have larger relative errors compared to the MAE values alone. For instance, as seen in Figure 6.7 during March NO4 had an error of 53%. This values however corresponds to 169 MWh/h (found in Appendix A.3.2), which in many cases is not that large. It is also important to remember that the data error described earlier was in March, and could have an effect on the aggregated results for that month. Especially in SE3 where the error occur.

As seen in during the case study in Section 5.2 DK1 is the area where the difference between operation day and reference day for wind power production is the largest. The overall significant improvement on the estimation result for this area could therefore be a response to the added shifts in the DK1 market curves.

SE3 also stands out as an area with large improvements. This is a highly populated area with much activity. As seen in Section 5.2, it is also the area with one of the largest market curve parameter differences from the reference day to the operational day. Based on the presented figures, one can see how these large market curve shifts has improved the SE3 results.

	Euphemia values - Percent of MA flow											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	42 %	17 %	13 %	2 %	7 %	15 %	30 %	7 %	17 %	9 %	33 %	8 %
February	34 %	18 %	17 %	2 %	10 %	10 %	43 %	10 %	12 %	6 %	23 %	7 %
March	58 %	23 %	17 %	4 %	13 %	10 %	53 %	11 %	13 %	8 %	42 %	8 %
April	48 %	17 %	13 %	5 %	13 %	9 %	43 %	23 %	20 %	10 %	35 %	10 %
May	45 %	17 %	19 %	7 %	16 %	14 %	31 %	29 %	25 %	8 %	24 %	11 %
June	32 %	12 %	18 %	15 %	19 %	29 %	28 %	19 %	29 %	5 %	36 %	8 %
July	27 %	9 %	7 %	34 %	44 %	25 %	32 %	11 %	30 %	7 %	28 %	11 %
August	20 %	9 %	8 %	35 %	33 %	32 %	23 %	12 %	17 %	8 %	39 %	10 %
September	24 %	10 %	10 %	25 %	15 %	15 %	32 %	10 %	14 %	11 %	30 %	9 %
October	25 %	12 %	15 %	10 %	24 %	20 %	19 %	15 %	17 %	10 %	24 %	11 %
November	44 %	18 %	9 %	3 %	15 %	22 %	7 %	14 %	14 %	7 %	20 %	12 %
Yearly	34 %	14 %	13 %	7 %	16 %	16 %	27 %	13 %	18 %	8 %	30 %	9 %

50 %
25 %
0 %

Figure 6.7: Illustratin of monthly results for each bidding area as a fraction of the mean absolute flow. The results are obtained with th Euphemia estimation.

	Referance day - Percent of MA flow											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	116 %	46 %	16 %	5 %	17 %	27 %	53 %	18 %	27 %	10 %	37 %	16 %
February	100 %	46 %	23 %	7 %	21 %	19 %	70 %	20 %	21 %	9 %	39 %	14 %
March	108 %	51 %	20 %	8 %	23 %	18 %	90 %	21 %	20 %	13 %	51 %	18 %
April	130 %	42 %	14 %	10 %	32 %	14 %	71 %	34 %	30 %	13 %	50 %	18 %
May	136 %	44 %	22 %	16 %	31 %	25 %	55 %	51 %	33 %	10 %	51 %	19 %
June	93 %	34 %	22 %	25 %	34 %	42 %	41 %	23 %	38 %	7 %	43 %	17 %
July	89 %	30 %	10 %	52 %	79 %	38 %	65 %	18 %	36 %	8 %	50 %	16 %
August	74 %	26 %	13 %	38 %	60 %	43 %	29 %	15 %	23 %	14 %	42 %	18 %
September	69 %	25 %	19 %	38 %	23 %	31 %	70 %	18 %	18 %	19 %	43 %	16 %
October	80 %	26 %	20 %	15 %	44 %	33 %	41 %	25 %	20 %	13 %	43 %	15 %
November	93 %	44 %	14 %	9 %	30 %	38 %	24 %	20 %	13 %	15 %	40 %	20 %
Yearly	94 %	35 %	17 %	13 %	31 %	27 %	49 %	22 %	23 %	11 %	45 %	17 %

50 %
25 %
0 %

Figure 6.8: Illustratin of monthly results for each bidding area as a fraction of the mean absolute flow. The results are obtained with th Reference day simulation.

MAE as a fraction of maximum flow

Figure 6.9 and Figure 6.10 illustrate the aggregated MAE for each bidding areas as a fraction of maximum flow. The maximum flows used as the reference for the presented values, are the same for each time period. This gives an opportunity to more easily study the results for each timer period compared with the mean average flow results. The maximum flows are not presented here, but can be found in Appendix A.2.

	Euphemia values - Percent of max flow											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	8 %	6 %	7 %	1 %	5 %	6 %	11 %	5 %	7 %	4 %	4 %	4 %
February	9 %	5 %	9 %	1 %	6 %	5 %	8 %	6 %	5 %	4 %	3 %	3 %
March	12 %	6 %	8 %	2 %	7 %	7 %	10 %	6 %	6 %	4 %	5 %	3 %
April	10 %	5 %	6 %	2 %	7 %	6 %	7 %	7 %	7 %	5 %	4 %	4 %
May	9 %	5 %	9 %	1 %	7 %	6 %	7 %	5 %	9 %	4 %	4 %	3 %
June	8 %	5 %	8 %	1 %	6 %	8 %	8 %	7 %	8 %	3 %	5 %	2 %
July	8 %	4 %	4 %	2 %	6 %	7 %	7 %	5 %	6 %	4 %	3 %	3 %
August	6 %	4 %	6 %	3 %	6 %	10 %	10 %	6 %	9 %	4 %	4 %	3 %
September	7 %	4 %	6 %	2 %	5 %	6 %	8 %	5 %	7 %	4 %	4 %	3 %
October	7 %	5 %	7 %	2 %	8 %	7 %	9 %	6 %	11 %	5 %	3 %	4 %
November	11 %	6 %	5 %	1 %	6 %	6 %	5 %	7 %	8 %	4 %	3 %	5 %
Yearly	9 %	5 %	7 %	2 %	6 %	7 %	8 %	6 %	7 %	4 %	4 %	3 %

25 %
12,5 %
0 %

Figure 6.9: Illustratin of method used when aggregating bidding areas into larger regions.

Figure 6.10 illustrate the net position values before the market curves were adjusted, the so called reference day values. The figure gives an overall similar picture as the mean absolute flow values, but the maximum flow results for each area can however be seen as more even in terms of percentage values. DK1 still stands out as the area with the largest errors for the reference day, and in general experiences a large improvement after the Euphemia estimation.

Most of the Norwegian areas start out some of the overall largest areas for the reference day results compared to the results in figure 6.8. The results after the Euphemia estimation is however similar to the mean absolute flow case.

	Referance day - Percent of max flow											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	23 %	15 %	8 %	3 %	11 %	12 %	20 %	12 %	11 %	5 %	5 %	7 %
February	25 %	12 %	12 %	3 %	12 %	10 %	13 %	11 %	8 %	5 %	5 %	6 %
March	23 %	13 %	9 %	3 %	12 %	12 %	17 %	12 %	9 %	7 %	6 %	7 %
April	27 %	13 %	6 %	3 %	16 %	9 %	12 %	11 %	10 %	6 %	5 %	6 %
May	27 %	14 %	11 %	3 %	14 %	12 %	12 %	9 %	11 %	6 %	8 %	6 %
June	25 %	13 %	10 %	2 %	11 %	11 %	12 %	8 %	10 %	5 %	6 %	5 %
July	24 %	12 %	6 %	2 %	11 %	11 %	15 %	8 %	7 %	5 %	5 %	4 %
August	22 %	12 %	8 %	3 %	11 %	13 %	12 %	7 %	12 %	8 %	4 %	6 %
September	20 %	12 %	11 %	3 %	8 %	13 %	17 %	8 %	9 %	7 %	5 %	5 %
October	21 %	10 %	10 %	4 %	15 %	12 %	19 %	11 %	13 %	6 %	5 %	6 %
November	23 %	14 %	8 %	3 %	13 %	10 %	16 %	10 %	7 %	7 %	7 %	7 %
Yearly	24 %	13 %	9 %	3 %	12 %	11 %	15 %	9 %	10 %	6 %	5 %	6 %

25 %
12,5 %
0 %

Figure 6.10: Illustratin of method used when aggregating bidding areas into larger regions.

The main difference between the two representations are the SE3 results. The values in Figure 6.9 and 6.10 illustrates SE3 as an area with overall good results compared to the other Nordic areas, but in Figure 6.7 and 6.8 SE3 represents one of the areas with the largest errors. The reason for this deviation could lie in the fact that SE3 is an area containing large shares of nuclear power production. This is typically base load production units, and it is difficult to fast regulate the production amount. It is therefore reasonable to assume that SE3 could have a very large maximum flow, compared to the mean absolute flow, in certain peak load hours. This might be one of the reasons why the MAE as a fraction of maximum flow and as a fraction of mean absolute flow can seem this different. It is therefore important to check the actual MAE together with the relative values in order to get a clear sense of the simulation results.

From Figure 6.9 one can see that the monthly errors are overall fairly similar throughout the simulation year. The largest percent values for each bidding area are distributed rather evenly during the year, and one specific season or month does not stand out as a more problematic estimation period.

Weekdays

Figure 6.11 shows the total mean absolute error per Nordic bidding area for the Euphemia estimations. The values are found by adding the hourly absolute error for all bidding areas for each weekday, and later divide by the number of added values - creating the total mean absolute error per bidding area for each weekday. The figure is scaled by color in order to easily compare the values.

The figure shows that the average absolute error for the Nordic system is in general larger for Saturdays and Sundays, closely followed by Mondays. This seems reasonable since the the reference day for Saturdays and Sundays are the previous weekend, and Mondays have Fridays as the reference day. It is expected that the reference day market curves are more different from the operational day the further these dates are apart. This is a very brief evaluation, and in order to make any clear conclusions it could be recommended to do more thorough studies of the different weekdays. One option could be to make separate evaluations for each bidding area, or for each individual week during the simulation period.

	Mean absolute error per bidding area [MWh/h]						
	Mon	Tue	Wed	Thu	Fri	Sat	Sun
January	248	141	181	155	186	308	310
February	205	163	157	148	206	264	211
March	289	219	200	180	213	291	259
April	273	185	166	175	217	289	282
May	224	204	172	137	176	287	289
June	184	178	234	185	195	290	298
July	240	130	144	148	160	248	235
August	197	151	150	135	145	354	359
September	240	166	144	145	186	254	220
October	201	145	156	187	218	352	403
November	247	174	177	165	166	296	269
Yearly	229	171	169	161	187	296	283

Figure 6.11: Illustration of the total mean absolute error per bidding bidding area for the different weekdays.

6.1.3 Large absolute errors

As described in Chapter 3, it is important find an estimation method that has as few large net positions errors as possible. Large errors can influence the system security and it is therefore important to develop an estimation approach that rather has many small errors than a few large.

Figure 6.12 illustrates the absolute error for each individual net position during the 2015 simulation. The errors are sorted from the largest to the smallest value, and are represented both for the reference day case and the Euphemia simulation. The figure clearly shows that the reference day has the overall largest errors throughout the simulation, starting at almost 3500 MWh/h. The exception is two very large errors from the Euphemia simulation, both with an absolute error larger then 6000 MWh/h. These were later found to be caused by an error in the data used for the simulation, and are not seen as valid results.

In addition to the overall difference in absolute error, it was seen as interesting to evaluate which areas in general represents the largest absolute errors during the 2015 simulation. This could given an indication of where further potential development of the method might be needed. Figure 6.13 shows the area distribution of the largest absolute errors during the 2015 simulation. The first column states that 60% of the top 10 largest absolute error were in SE3, 20% were in NO2, and 10% in both NO5 and SE1.

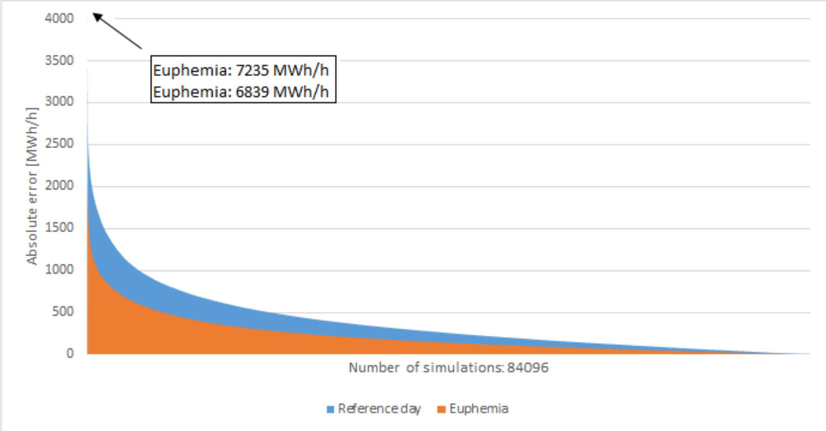


Figure 6.12: Plot of all absolute errors during the 2015 simulations. The figure shows values for the Reference day and the Euphemia simulation.

	Number of simulations with largest error			
	10	100	1000	2000
DK1	0 %	0 %	3 %	6 %
DK2	0 %	0 %	0 %	0 %
FI	0 %	0 %	4 %	5 %
NO1	0 %	0 %	0 %	1 %
NO2	20 %	22 %	24 %	21 %
NO3	0 %	0 %	0 %	0 %
NO4	0 %	0 %	0 %	2 %
NO5	10 %	15 %	11 %	10 %
SE1	10 %	18 %	13 %	15 %
SE2	0 %	9 %	15 %	14 %
SE3	60 %	36 %	27 %	24 %
SE4	0 %	0 %	3 %	2 %

Figure 6.13: Table illustrating the distribution between the Nordic bidding areas for the largest absolute errors during the 2015 Euphemia simulation. The distribution is evaluated for the top 10, 100, 1000 and 2000 largest absolute errors.

The figure clearly indicates that the largest absolute errors are in SE3 and NO2, followed by NO5 and SE1. The SE3 percent value is especially high, and six out of the ten largest errors were in SE3. There can be many reasons for this situation - SE3 is the area with the by far largest production of nuclear power, and the changes in production might not influence the market curves as expected. Another possibility is that there are some factors for the SE3 market curves that are not correctly accounted for in the evaluated estimation approach.

It is important to emphasize that there is a relative difference, in terms of size between the areas and that this figure does not fully reflect these differences. For example, SE3 is the largest area in terms of electricity production and demand. NO2 and SE2 are fairly large in production, while NO5 is a bit smaller. Based on this notation, it could be seen as reasonable that the larger areas do experience some of the overall largest errors in the system.

In order to further investigate why these large absolute errors might occur, one hour containing the large absolute error for the simulation was given a more in depth evaluation. The chosen hour was Friday the 10th of April between 02:00 and 03:00.

Evaluation of 10.04.2015

This section examines the simulation of 10.04.2015 between 02:00 and 03:00. Due to the overall large errors for all of the Nordic bidding areas, it was seen as a very interesting case to examine further. The results for SE3 represents the simulation with the largest single error during the 2015 simulation.

The hours have resulting net positions from the Euphemia estimation that have values further from the actual net position compared to the reference day case. The block orders added to the system, or the difference between the operational day and reference day, is not significant large for any Nordic bidding area except for SE3. The added shift for SE3 is 1374 MW to the demand curve. SE3 is also the area with the largest net position errors. This indicates that the large SE3 shift might be the reason for the overall errors in the Nordic system.

By evaluating the Nuclear power production in SE3 one can see that the added shift mainly origins from a large change in nuclear power production. This value is also confirmed by evaluating the nuclear production data. This could indicate that the change in nuclear production might not effect the market curves as expected in this situation. It is however hard to verify this notation unless further studies are made. Another option could also be that there are factors or parameters effecting the day to day changes in the system that are not accounted for in this simulation.

One other options were investigated to find the reason for the SE3 increase. one was checking for possible UMMs [1] affecting the market. There was however not found any relevant UMMs for this period.

6.1.4 Density functions

Figure 6.15 and 6.14 shows a graphical representation of the errors from the Euphemia estimations and the Similar Net Demand approach. The density functions are represented with the Kernel Smoothing function.The function and its nature is described in Section 4.7.1. It is important to emphasize that the Kernel Smoothing function is a

The figures clearly illustrate that both estimation methods have errors with the highest density close to 0 MWh/h. The two estimation approaches have fairly similar results for some of the bidding areas, while other are more different. The density function for the Norwegian

[1] Urgent Market Messages [32]

bidding areas have for instance in some cases clearly different shapes, especially for the areas NO1 and NO4. The difference between the two estimation approaches are however more similar for the Swedish areas.

The figures give a general impression that the Euphemia estimation have fewer large errors then the alternative approach. This is because the Euphemia plot often has a higher density close to zero.

Many of the illustrated density functions for the Euphemia approach have a clear resemblance to the normal distribution. In order to provide a better impression of how well the estimation approach reduces large error, the mean error and 90% interval was found. Meaning that 90% of the simulation results where within this area. The values are listen in Table 6.1 and area also compared with the reference day case.

Firstly, the table illustrates that the mean origins around zero for both methods, and is quite similar for all Nordic bidding areas. The reference day have slightly lower mean values then the Euphemia estimation. The 90% interval between X1 and X2 can however be quite different for the different bidding areas. Two areas, DK1 and NO2, particularly stands out from the rest. With the given interval this would mean that 10% of all error in DK1 are larger then 1400 MWh/h, but are reduced to 570 MWh/h for the Euphemia estimation. It is important to note that the SE3 values could potentially be affected by the error in the data source described earlier in the report.

	Euphemia estimation			**Reference day**		
Area	**Mean**	**X1**	**X2**	**Mean**	**X1**	**X2**
DK1	8	-570	578	3	-1425	1432
DK2	4	-227	234	-4	-503	494
FI	25	-510	559	2	-610	615
NO1	-4	-330	321	2	-446	450
NO2	-34	-852	784	6	-1337	1348
NO3	-9	-318	300	-4	-470	462
NO4	-25	-398	348	-7	-595	581
NO5	-30	-669	610	4	-915	922
SE1	-18	-696	659	-8	-801	785
SE2	-41	-749	668	-10	-952	931
SE3	0	-902	901	27	-1122	1175
SE4	3	-421	427	4	-640	647

Table 6.1: Table illustrating key values for the 90% interval for the Euphemia estimation and reference day method.

The representation of the 90% interval assumes that the Euphemia simulation errors and reference day errors can be represented by a normal distribution. If this is not the case, this

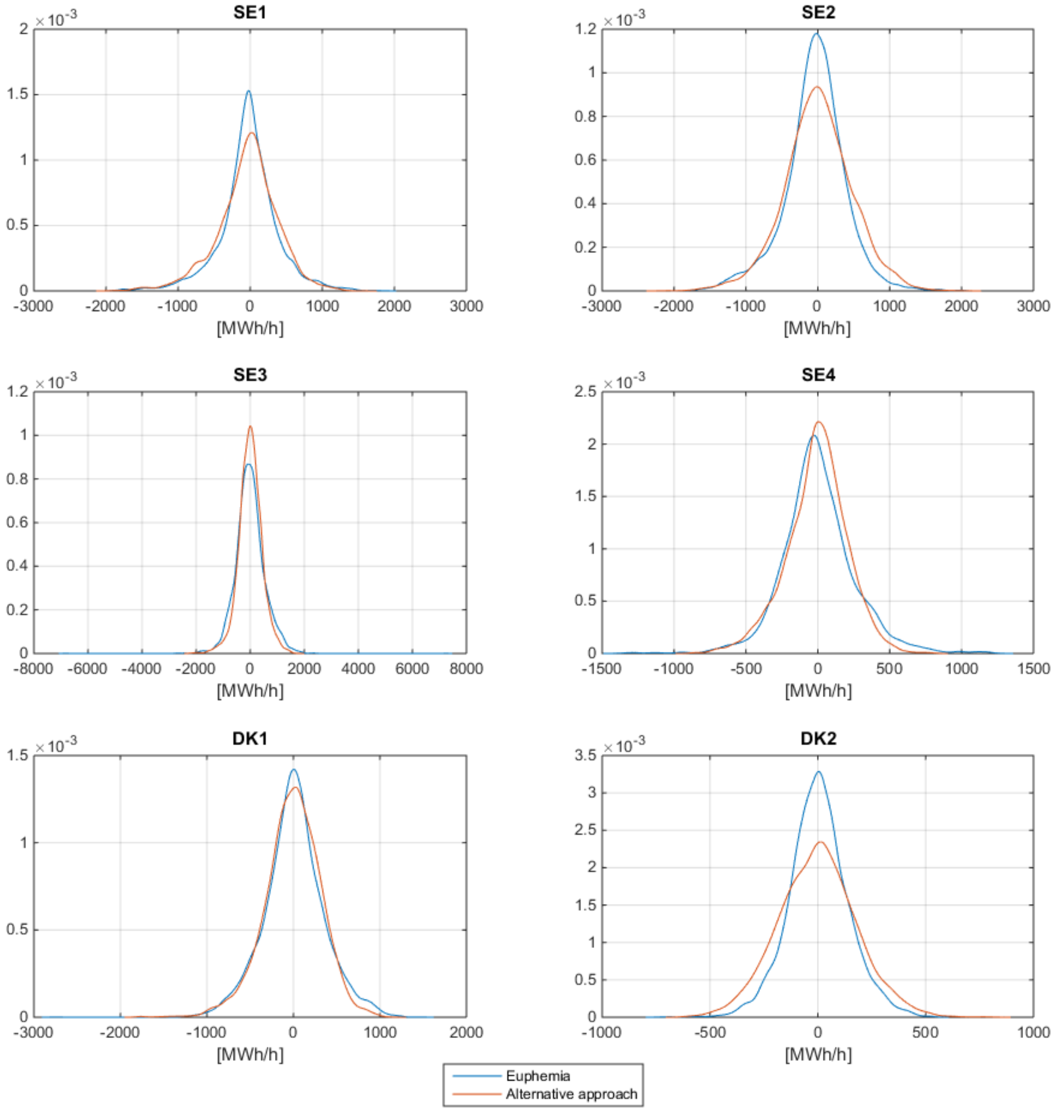


Figure 6.14: Plot of the estimation errors as density functions.

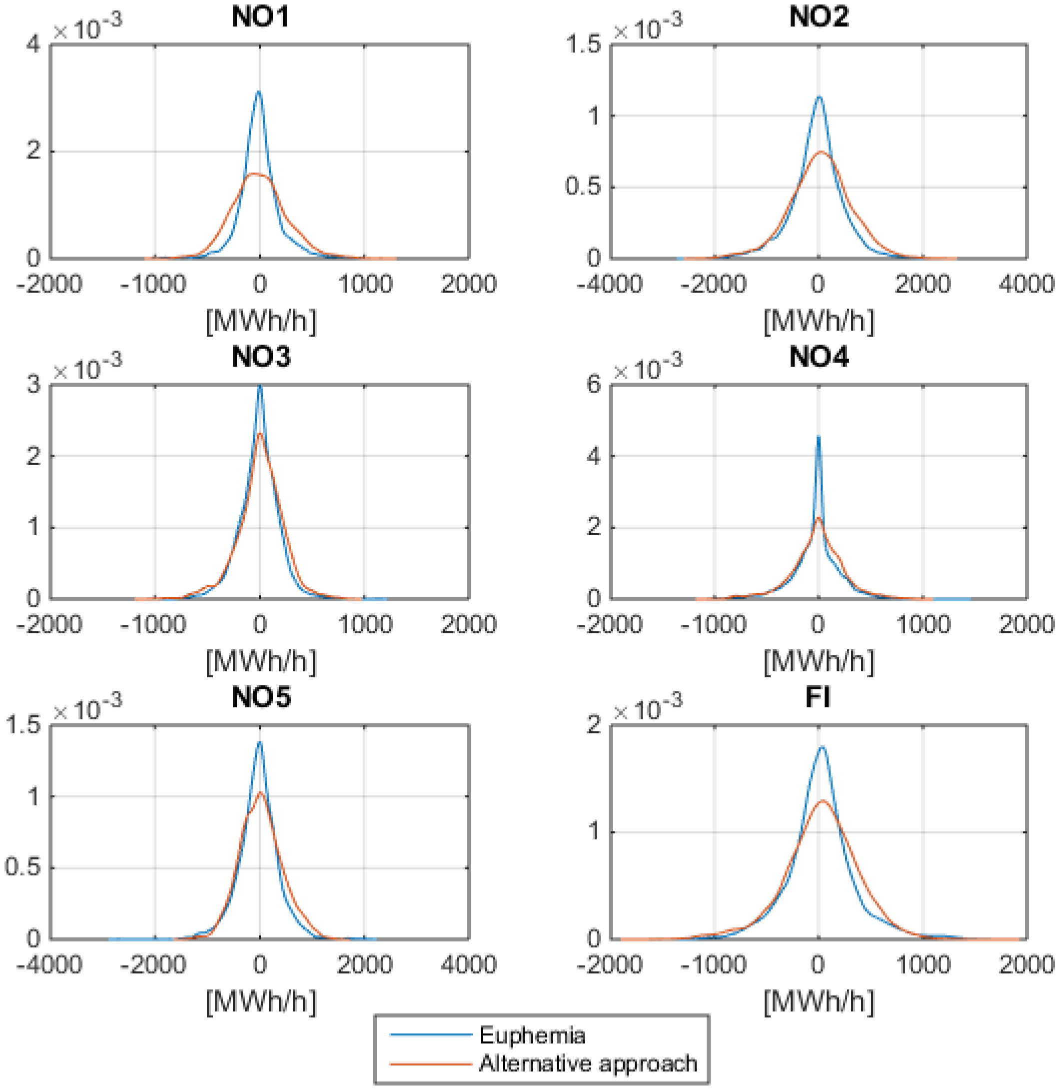


Figure 6.15: Plot of the estimation errors as density functions.

might cause a limitation to the evaluation of the results.

6.1.5 Evaluation of selected events

This section gives a more thorough examination of selected events in the 2015 simulation. The purpose of this evaluation is to get a more in depth understanding of how well the estimation approach works, and if the added parameters influences the system as intended.

Due to the amount of simulation hours it is not possible to evaluate every single result for each bidding area. As described in earlier sections the results were instead aggregated for larger time periods. By aggregating the simulation results, one gets a clear overview of the main trends. However, in some cases one can loose important detailed information of how the estimation approach reacts to different changes in the model. By evaluating single events, this section will try to give a more detailed impression of the simulation approach. It is however important to emphasize that these are single events, and may not be representative for all simulations hours during the 2015 simulation.

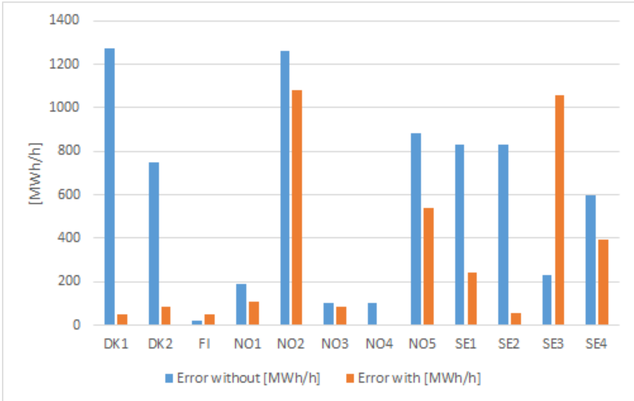
Case A: Adding Nordic wind power production
In order to give a better understanding of how the implementation of wind power production affects the system, one hour was simulated with and without these changes using the Euphemia approach. The specific hour was chosen based on how large the wind power production delta, or shift between operational and reference day, was for the given hour. The investigated day was chosen as the 14th of February 2015 between 14:00 and 15:00. All other market parameters, such as consumption and nuclear power production, were implemented in both simulations.

The results from the simulations are presented in Figure 6.16a and 6.16b. Figure 6.16a illustrates the error between the simulated net positions with and without the implementation of wind power production. The table also presents the added market curve delta from wind power production. Figure 6.16b shows the NP errors illustrated as a bar chart.

The figures show that by compensating the market curves with wind power production one reduces the overall errors for the Nordic area by astonishing 3329 MWh/h. Individually, most of the Nordic areas experience an improvement after the wind power production delta has been added to the system. DK1, DK2 and SE2 has an overall largest improvement for all areas. These are some of the areas with the largest added wind power production delta during the simulation, indicating that the added wind power affects the system in a satisfying manner.

Area	Delta [MWh/h]	Error without [MWh/h]	Error with [MWh/h]	Improvement [MWh/h]
DK1	-2508	1274	51	1223
DK2	-689	751	84	668
FI	-272	19	48	-29
NO1	0	190	109	82
NO2	-61	1259	1079	180
NO3	-99	100	82	18
NO4	-15	100	1	99
NO5	-107	884	538	346
SE1	-309	832	243	589
SE2	-1133	833	55	778
SE3	-1509	232	1059	-826
SE4	-997	598	396	202
Sum		7073	3744	3329

(a) Table of absolute error for all bidding areas



(b) Figure comparing the absolute error for all bidding areas.

Figure 6.16: Table and figure illustrating the absolute errors of the simulated net positions, with and without wind power production compensation.

The exceptions from improvements are SE3 and FI, where the absolute error was larger after the implementation. Since SE3 is the area with the second largest wind power delta, see Figure 6.16b, it seems odd that the absolute error increases. Especially when DK1 and SE2, areas that also and large wind power deltas, experience very good results.

There might be several reasons for these type of incidence. One possibility is that the market curves in some cases slightly change shape from the reference day to operational day. Another possibility is that there might be parameters or factors in the system that the Euphemia estimation approach has not accounted for, or that some of the already added parameters affects the system in a different way then first anticipated. An other explanation can be that small errors around the system are accumulated in SE3, making the impression that the error originated in this area, even though this might not be the case.

The option of extra block orders and UMMs affecting the results were investigated. There was no extra block orders added to the system, excluding this option as a reason for the SE3 errors. The UMMs from the day show that there was a line outage ending on the 14th that was connected to SE3. This outage could have an affect on the Day-ahead market bidding, and changing the shape of the market curves.

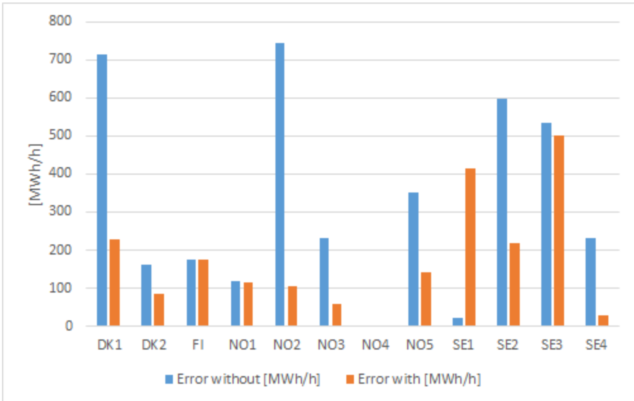
It is difficult to explain why some errors occurs and the reason behind them, but the example however illustrates overall better results for the Nordic system in general after the implementation of wind power production. Two of the Nordic areas show a very good improvement of the absolute errors after the implementation, reducing the largest errors for the simulation.

Case B: Adding Nordic consumption

Case B gives a short evaluation on the effect of adding Nordic consumption to the estimation model. One selected hour was chosen as the example, and two simulations with and without the Nordic consumption delta was executed. The resulting net position results are illustrated in Figures 6.17a and Figure 6.17b, in table form and as bar chart. The errors after implementing the consumption deltas are overall smaller then before the implementation, which can be seen in Figure 6.17a. After the implementation all Nordic bidding areas experience an individual improvement of the net position. The only exception is SE1 which ends up with a net position further from the actual value after the implementation of the consumption data. Figure 6.17b illustrate a large improvement for DK1 and NO2. The improvement for the resulting areas are positive, but are more or less moderate compared to the other areas.

Area	Delta [MWh/h]	Error without [MWh/h]	Error with [MWh/h]	Improvement [MWh/h]
DK1	-248,5	713	228	485
DK2	-34,4	163	84	79
FI	63,9	176	176	0
NO1	-116,7	120	114	5
NO2	-35,5	745	107	639
NO3	104,6	233	59	174
NO4	6,3	0	0	0
NO5	-55	352	142	210
SE1	-12,6	22	413	-391
SE2	-103,2	598	218	380
SE3	-663,4	533	503	31
SE4	24,7	230	29	201
Sum		3885	2071	1813

(a) Flower one.



(b) Flower two.

Figure 6.17: Adding the Nordic consumption to the evaluated net position estimation approach

Similar to the Case A it is not known why some areas get higher absolute errors after the parameters are implemented, and there can be many factors influencing the results. It is however worth noticing that the overall Nordic results have been improved, and the largest errors have been reduced.

Case C: Adding Nuclear power

Case C, adding nuclear power, was tested on a more aggregated level then case A and B. The five first weeks of the 2015 simulation, spanning from 19.01.2015 to 22.02.2015, was simulated with and without the implementation of nuclear power. There are only two bidding areas in the Nordic region with nuclear power production, SE3 and FI, these areas are therefore emphasized in this evaluation.

Figure 6.18 shows the MAE for areas SE3 and FI throughout the five simulated weeks. As described in Chapter 5, SE3 is the area with the largest production of nuclear power, and it is therefore expected that the largest changes will be in SE3. It is also expected that the nuclear power only has a large impact on the results certain days. This is because nuclear power units are so called base load units and does not have as rapid changes in production. These expectations are reflected in Figure 6.18, where the simulation results are somewhat similar for most weeks, but the MAE are clearly reduced for SE3 in week 4 and 8.

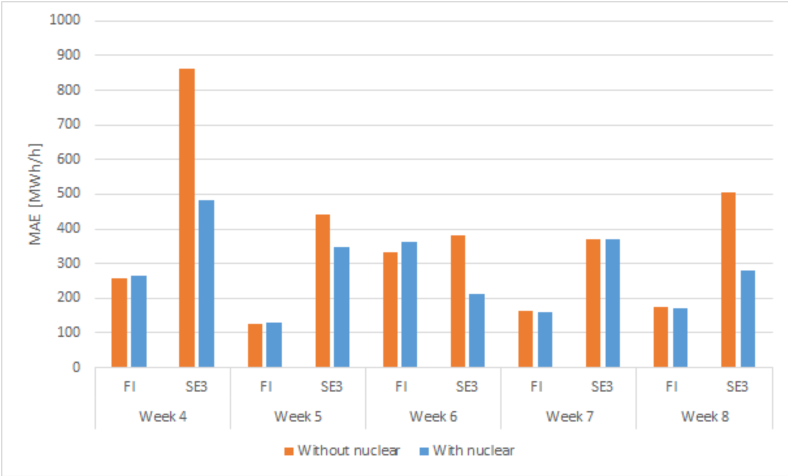


Figure 6.18: 5 weeks test case from 19.01.2015 to 22.02.2015. The table illustrates the mean absolute error for SE3 and FI - the only Nordic areas with nuclear power production.

The simulation results for all Nordic areas are illustrated in Figure 6.19. The values are here normalized with the maximum flow from 2015 and for the mean absolute flow for each bidding area. The figure shows the results from week 4, which was the week with the most improvements. From the figure one can notice that the implementation of nuclear power also effects some of the other Nordic areas, reflecting that all areas are dependent of each other.

	Max flow		MA flow	
	without nuclear	with nuclear	without nuclear	with nuclear
DK1	8 %	8 %	55 %	55 %
DK2	5 %	6 %	14 %	14 %
FI	9 %	9 %	16 %	17 %
NO1	1 %	1 %	2 %	2 %
NO2	4 %	4 %	6 %	6 %
NO3	7 %	5 %	20 %	15 %
NO4	17 %	13 %	35 %	27 %
NO5	4 %	4 %	5 %	5 %
SE1	6 %	6 %	14 %	15 %
SE2	4 %	3 %	9 %	7 %
SE3	9 %	5 %	67 %	38 %
SE4	3 %	3 %	7 %	7 %

Figure 6.19: Week 4 during the nuclear test, from 19.01.2015 to 25.01.2015. The table illustrates the MAE as a fraction of the maximum flow and as a fraction of mean absolute flow.

6.2 Case 2: 2015 with two weeks old data

In the second case of the 2015 simulation seven week from 25th of May to the 12th of July was simulated. The difference between this simulation, and the one executed in the first simulation case is that the data was two weeks old, meaning that all reference days for each simulated were two weeks older then the reference days used in case 1.

Since the reference days were two weeks older then the simulations in case 1, one would expect that the overall errors would be larger than before. This is mainly because the given days are further apart, and the market curves could potentially have fewer similarities.

Figure 6.21 illustrates the MAE for each Nordic country, and the Nordic synchronous area. The Figure clearly shows that the up-to-date data gives overall better results compared to the two other methods illustrated in the figure. The reference day method and the Euphemia estimation with two weeks old data generate similar results for each bidding area, except from DK and FI. In the DK area the reference day clearly generate the largest MAE. In Finland however, the reference day have similar results as Denmark.

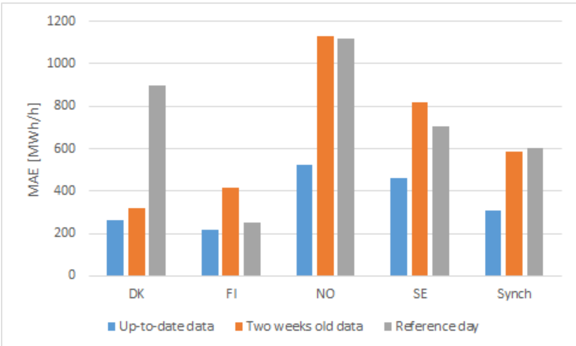


Figure 6.20: Plot of the estimation errors as density functions.

Figure 6.20 gives the same representation as Figure 6.21, but illustrates the aggregated MAE for each bidding area. The figure shows the overall same trends, but clearly states a large difference for NO5. Comparing NO5 and the other areas, this can indicate that the market curves have larger changes over the two weeks then the other market curves.

In Case 1, DK1 was one of the areas with the largest overall improvement, and was also the area with the largest changes in wind power production. It is therefore interesting to see that this is also one of the areas with the smallest difference between case 1 and 2. This might give indications that most of the market curve changes in this area are reflected in the price incentive market bids. This is however not been tested any further, and it is difficult to make clear assumptions.

The case 2 results indicate that the estimation approach can gives better results by using up-

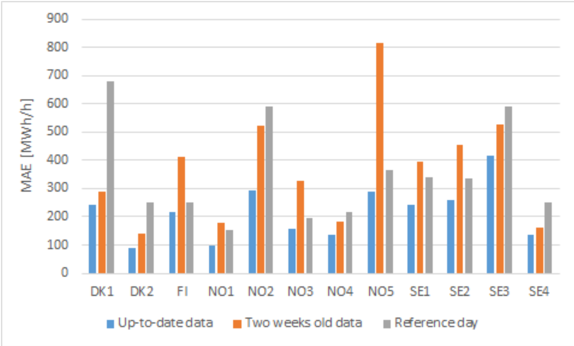


Figure 6.21: Plot of the estimation errors as density functions.

to-date data. The simulation period is however short, and it is difficult to predict how much better the results will be in general over a longer time period and multiple seasons.

It should be emphasized that this Figure does not illustrate the results in relative terms and the size of the bidding area should be kept in mind when comparing the areas.

7. Additional research

This chapter gives a brief description of some additional studies that were carried out during the research. They are not seen as a part of the main results, but serves the function as a supplement to decisions and assumptions made during the research process.

7.1 Altering market curves in Simulation Facility with block orders

Since SF is a fairly new simulation tool, Statnett has not jet used the program for similar purposes as this project. Therefore, some initial test were done in order to check if SF reacts as anticipated to the additional insensitive block orders.

A few scenarios from case 1, Section 5.2, was tested. Due to the amount of simulations only a few scenarios were evaluated, this may cause limitations to the project, but it is however assumed that the tested scenarios can give a representative results for the overall research.

Test 1: Equal prices
The chosen simulations had fairly equal prices before and after the block orders were added. If the prices are equal it is anticipated that the difference in the amount of accepted block orders equals the added amount.

The first test is for 3rd of June between 15:00 and 16:00 in DK1. The prices were almost the the same for both cases. The results are presented in Table 7.1. The columns "Reference day" and "Euphemia" illustrated the amount of accepted block order for each simulation. The column Difference" gives the difference between the reference day and Euphemia simulation, while "Block order" is the block order amount added by the student. As anticipated, the change in the amount of accepted block orders after the Euphemia simulation is almost the same as the amount added by the student.

	Reference day	Euphemia	Difference	Block order
Supply	1,2	28,2	27	23,3
Demand	6,6	337,6	331	331

Table 7.1: Representation of the changes in block orders before and after the Euphemia simulation. Case with almost equal prices. All values are in MWh/h

Test 2: Price reduction

The second test was chosen as a case where there was a reduction in price. If the price is reduced one would anticipate a simulation outcome where the difference in accepted block orders are equal to the added amount for the supply curve, but the amount of added block orders to the demand curve can potentially be significant larger.

The evaluated case for this scenario was chosen as the 6th of October between 20:00 and 21:00 in SE2. In this period the price went from 16 EUR/MWh for the reference day to 13 EUR/MWh after the Euphemia simulation. The results are presented in Table 7.2 and confirms the anticipated outcome.

Curve	Reference day	Euphemia	Difference	Block order
Supply	43	269	226	226
Demand	3	753,7	750,7	331,7

Table 7.2: Representation of the changes in block orders before and after the Euphemia simulation. Case with price decrease. All values are in MWh/h.

The table also reflects that large amounts of bids can be accepted to the system if prices are not equal, indicating how price sensitive the market curves are.

Test 3: Price increase

The final tested scenario is for an increase of price between the reference day and the Euphemia simulation. The selected case is for NO3 at the 8th of September between 20:00 and 21:00. Here, the area price was increased by almost 3 EUR/MWh. The block orders related to the simulation are presented in Table 7.3 below.

Curve	Reference day	Euphemia	Difference	Block order
Supply	203.8	303.8	100	0
Demand	0	88.7	88.7	88.7

Table 7.3: Representation of the changes in block orders before and after the Euphemia simulation. Case with a price increase. All values are in MWh/h

Since this is the opposite case of test case 2, one would expect that the amount of accepted block orders for the supply curve is larger then the amount added for the Euphemia simulation. By examining Table 7.3, one can see that the difference in accepted block orders are 100 MWh/h larger then the amount of added block orders. This confirms the expected outcome. The difference between the reference day and Euphemia simulation is the same as the amount of added block orders for the demand curve. This is also a reasonable outcome, since the price has increased and no additional demand curve block orders would be excepted.

This test case only checks if the amount of incentive bids were added to the system, it does not reflect where in the system, witch bidding area, the block order is compensated. It is important to emphasize that it can be very hard, or even impossible, to predict how the added block orders distribute in the system when there are a large number of connected bidding area. The changes depends, among others, on exchange capacity between areas and the marginal cost related to different bids in the hole system. It is therefore hard to predict where in the market one extra unit of demand in one area will be produced.

7.2 Flow on HVDC cables

In addition to the net positions, Statnett has to estimate the flow on all HVDC cables in the system for the FBMC base case. This was not a part of the initial project formulation, but it was seen as interesting to briefly evaluate of the flows for the Euphemia estimation.

Table 7.4 illustrates the mean absolute error for each HVDC cable during the 2015 simulation. The values are weighted with the maximum capacity for each cable in the column to the far right. The table indicates and overall error around 10% for all areas. The relative values were compared with the same values for the reference day case, and are illustrated in Figure 7.1.

The figure indicates an overall improvement for the HVDC flows. Some areas indicate a larger improvement then others. The least difference between the two methods are for NorNed and Estlink. These are however areas with an in general low mean absolute error compared with the other HVDC cables.

It is important to emphasize that this evaluation only focus on the overall average values for the hole period, and therefore detailed information might be lost. This could for example be crucial hours with very large errors. Therefore, this evaluation only gives an indication of the results, but further and more detailed analysis should be made before any clear conclusions can be taken. A similar table as 7.4 is given for the Reference day in Appendix A.5.

Interconnection		MAE [MWh/h]	MAE [% of max capacity]
NorNed	NO2-NL	12	2
Skagerrak	NO2-DK1	110	8
Storebælt	DK1-DK2	76	13
Kontiskan	SE4-DK2	123	10
Fenno-Skan	SE3-FI	107	9
Kontek	DK2-DE	72	13
Baltic Cable	SE4-DE	37	13
SwePol	SE4-PL	22	6
NordBalt	SE4-LT	-	-
Estlink	FI-EE	117	13

Table 7.4: Overview of the mean absolute error for the HVDC cables in the Nordic region during the 2015 simulation with up-tp-date dates. The table also shows the mean absolute error as a fraction of the average capacity in 2015

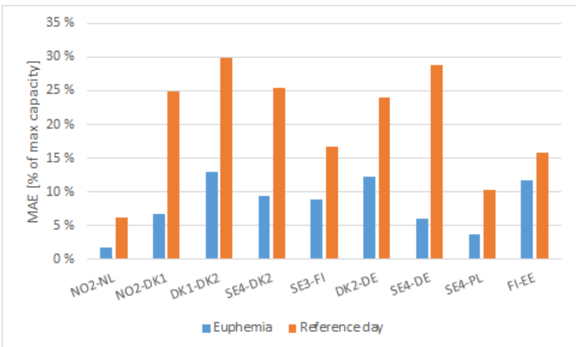


Figure 7.1: The MAE as a fraction of maximum flow for HVDC cables in the Nordic system.

8. Conclutions and future work

8.1 Conclution

Statnett and the other Nordic TSOs are currently investigating the possibility of implementing the Flow Based Market Clearing approach in the Nordic power market. Before a potential Nordic launch there are still some aspects of the model in need of further investigation.

Simulation Facility is a new simulation tool provided by the PCR project, and enables the user to preform market simulations with the Euphemia algorithm. It is shown that it is possible to change the amount of price insensitive bids for the market curves by adding extra block orders for each Nordic bidding area. The downside of this method is that production and consumption quantities for each area will be incorrect after the market clearing, and would have to be corrected at a later stage.

The simulation results show an overall improvement of the estimated net positions when comparing the results from the Euphemia estimations and the results from the reference day. The most significant improvements are for the Danish and Norwegian areas, but there is also a good overall improvement for SE3. It is assumed that the results can give indications of how well the estimation approach is, but more study is needed before any clear conclusions can be made.

Compared to the reference day, the Euphemia estimation has in general fewer large absolute errors, which is important from a system security and reliability point of view.

The implementation of consumption, wind power production and nuclear power production seems to have a positive effect on the results at a more detailed level as well as the aggregated values. From the results it is shown that the nuclear power production might have a large impact on the simulation outcome at certain days.

Simulations with two weeks old data gives results that might indicate results that are not as good as the up-to-date data case. The tested case was however for a short period, and further analysis should be made.

The Euphemia estimation approach seems to give reasonable good results for the tested period. One of the downsides of the method is however the amount of manual calculations needed in the simulation program "Simulation Facility". In addition, the program is quite new and there are still several bugs in the system, limiting the simulation reliability of the simulations to some extend.

8.2 Recommendations for future work

In order to do give a clear recommendation of how well the new estimation method works it is advised to do further test the approach on large simulations, especially for the case with two weeks old data. In addition, the data foundation used in this research is based on already known marked data, and simulations with forecasted data would be recommended for further evaluation of the method. It is later shown that there are some errors in the data, and it would be recommended to execute test cases where the used data is as good as possible.

If this method should be further tested it is important that all processes of data has to be automated. They are in some extended automated for this project, but for more commercial use this should be more efficient and adaptable for alterations. This includes the amount of manual calculations in Simulation Facility, which today is cumbersome and would benefit from more simple procedures.

Since it is important to reduce large error further investigation on this topic could be recommend. For example by testing the estimation approach for events that are known to be unusual.

Moreover, it could be interesting to further evaluate the importance of a full PCR topology, or if the simplified model is good enough for future simulation.

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A. Appendices

A.1 Method

A.1.1 Collected simulation data

Area	Production	Source	Consumption	Source
DK1	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
DK2	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
FI	Wind total forecast	Statnett SF	Elspot volumes	Nord Pool
	Nuclear forecast	Statnett SF		
NO1	Measured wind power production	Statnett SF	Elspot volumes	Nord Pool
NO2	Measured wind power production	Statnett SF	Elspot volumes	Nord Pool
NO3	Measured wind power production	Statnett SF	Elspot volumes	Nord Pool
NO4	Measured wind power production	Statnett SF	Elspot volumes	Nord Pool
NO5	Measured wind power production	Statnett SF	Elspot volumes	Nord Pool
SE1	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
SE2	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
SE3	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
	Measured nuclear power production	Statnett SF		
SE4	Wind Power Prognosis	Nord Pool	Elspot volumes	Nord Pool
DE	Wind power forecast	German TSOs		

Table A.1: Overview of data used for the simulations. Several of the simulations

A.2 Maximum flow during 2015

Area	**Max import** [MWh/h]	**Max export** [MWh/h]	**Max NTC** [MW]	$\frac{Maxflow}{MaxNTC}$ [%]
DK1	2452	2862	4742	60,4
DK2	1890	1700	2885	65,5
FI	2977	1737	3716	80,1
NO1	6700	2645	9995	67,0
NO2	2400	5066	6346	79,8
NO3	1887	800	2700	69,9
NO4	748	1700	1950	87,2
NO5	488	4400	4700	93,6
SE1	2420	3451	5400	63,9
SE2	2943	7000	11900	58,8
SE3	9532	7080	16575	57,5
SE4	5200	2515	5215	99,7

Table A.2: Table presenting the maximum flow (import/export) for one area during 2015. The values represents the highest flow, either as import or export, from the given Nordic bidding area.

Area	**Max import** [MWh/h]	**Max export** [MWh/h]	**Max NTC** [MW]	$\frac{Maxflow}{MaxNTC}$ [%]
DK	3512	3966	6437	61,6
FI	2977	1737	3716	80,1
NO	4779	5602	6350	88,2
SE	4487	7065	10590	66,7
Synch	3849	5693	72160	7,9

Table A.3: Table presenting the maximum flow (import/export) for the Nordic countries and synchronous area during 2015. The values represents the highest flow, either as import or export

A.3 Additional results: Simulation case 1

A.3.1 Mean absolute monthly flows

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Yearly
DK1	559	729	596	596	577	759	790	866	824	752	717	718
DK2	619	507	495	572	585	719	780	886	869	745	581	679
FI	1521	1582	1367	1345	1401	1332	1747	1968	1674	1424	1715	1557
NO1	3525	3142	2718	2045	1235	621	299	589	491	1679	2651	1583
NO2	3497	2877	2661	2465	2272	1634	695	925	1740	1699	2188	1953
NO3	798	978	1275	1192	889	510	533	576	792	622	495	789
NO4	642	317	317	294	361	498	383	714	412	789	1118	515
NO5	2896	2386	2429	1444	752	1612	1951	2116	2073	1876	2077	1935
SE1	1408	1411	1491	1224	1199	911	702	1749	1709	2287	1941	1452
SE2	3237	4043	3611	3442	4029	4656	4117	3806	2542	3508	3378	3700
SE3	1240	1339	1173	955	1468	1319	981	867	1136	1011	1652	1176
SE4	2195	2066	2058	1832	1613	1625	1478	1678	1755	2015	1932	1819

Table A.4: Table presenting the mean absolute flow for each month and bidding areas during 2015

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Yearly
DK	854	816	901	945	835	1303	1408	1669	1591	1406	1189	1206
FI	1521	1582	1367	1345	1401	1332	1747	1968	1674	1424	1715	1557
NO	2880	2032	2233	1768	2196	2735	1915	2426	2903	2246	2862	2354
SE	1717	2681	2488	2995	2404	2773	4134	3516	1970	3388	2055	2821
Synch	2482	2091	2389	2262	1930	3305	3291	2994	2388	3246	2423	2653

Table A.5: Table presenting the mean absolute flow for each month and bidding areas during 2015

A.3.2 Mean absolute monthly error for the Nordic bidding areas

	Euphemia - values MAE [MWh/h]											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	235	108	204	79	261	117	194	210	241	289	410	186
February	250	89	265	62	293	99	136	245	173	257	306	145
March	348	115	229	112	350	131	169	268	199	272	497	157
April	286	96	170	102	332	112	127	329	240	347	339	187
May	259	101	270	88	356	122	112	221	304	304	358	177
June	239	87	242	95	306	149	139	304	261	224	473	125
July	215	73	124	101	304	135	123	222	211	278	272	159
August	173	84	167	206	307	182	163	261	304	311	342	164
September	198	85	171	121	254	117	131	204	243	267	345	156
October	190	88	212	163	399	131	148	284	378	344	242	225
November	314	106	159	87	328	109	82	292	268	247	331	238
Yearly	244	93	201	114	319	129	138	259	257	285	354	171

Figure A.1: Illustration of the mean absolute error for each Nordic bidding area throughout the simulation year. The MAEs are obtained by using the Euphemia estimation approach.

	Reference day values - MAE [MWh/h]											
	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
January	649	282	250	193	581	218	340	512	376	339	458	355
February	725	234	370	219	610	188	221	468	292	363	517	297
March	646	253	274	205	604	231	287	512	301	463	595	362
April	773	240	192	197	800	165	210	486	362	436	478	331
May	786	259	314	200	711	226	197	382	393	405	752	310
June	708	241	289	158	553	217	202	368	348	331	562	274
July	701	230	181	154	547	202	249	344	252	338	487	232
August	642	229	253	222	556	250	207	310	409	533	363	297
September	572	219	319	187	398	244	287	371	313	477	493	278
October	599	192	286	258	746	221	321	471	455	440	433	311
November	663	257	246	228	648	189	271	423	256	522	664	386
Yearly	677	237	272	201	609	215	250	416	341	425	524	307

Figure A.2: llustration of the mean absolute error for each Nordic bidding area throughout the simulation year. The MAEs illustrates the values for the given reference day.

A.4 Additional results: Simulation case 2

A.5 Additional research

	Week 4		Week 5		Week 6		Week 7		Week 8	
	without nuclear	with nuclear	without nuclear	with nuclear	without nuclear	with nuclear	without nuclear	with nuclear	without nuclear	with nuclear
DK1	55 %	55 %	34 %	34 %	26 %	28 %	30 %	30 %	33 %	34 %
DK2	14 %	14 %	22 %	22 %	18 %	18 %	17 %	17 %	16 %	16 %
FI	16 %	17 %	10 %	10 %	31 %	33 %	9 %	9 %	9 %	9 %
NO1	2 %	2 %	2 %	2 %	1 %	1 %	3 %	3 %	2 %	2 %
NO2	6 %	6 %	10 %	10 %	7 %	6 %	10 %	10 %	13 %	13 %
NO3	20 %	15 %	13 %	14 %	14 %	14 %	11 %	11 %	8 %	7 %
NO4	35 %	27 %	37 %	40 %	17 %	17 %	80 %	80 %	57 %	59 %
NO5	5 %	5 %	11 %	12 %	10 %	8 %	10 %	10 %	10 %	10 %
SE1	14 %	15 %	22 %	21 %	8 %	7 %	13 %	13 %	14 %	13 %
SE2	9 %	7 %	13 %	13 %	7 %	5 %	8 %	8 %	4 %	5 %
SE3	67 %	38 %	37 %	30 %	21 %	12 %	27 %	27 %	42 %	23 %
SE4	7 %	7 %	11 %	10 %	7 %	7 %	6 %	6 %	8 %	8 %

50 %
25 %
0 %

Figure A.3: 5 weeks test case from 19.01.2015 to 22.02.2015. The table illustrates the MAE as a fraction of the mean absolute flow for each Nordic bidding area.

Interconnection		MAE [MWh/h]	MAE [% of max capacity]
NorNed	NO2-NL	45	6
Skagerrak	NO2-DK1	406	25
Storebælt	DK1-DK2	176	30
Kontiskan	SE4-DK2	330	25
Fenno-Skan	SE3-FI	200	17
Kontek	DK2-DE	140	24
Baltic Cable	SE4-DE	177	29
SwePol	SE4-PL	62	10
NordBalt	SE4-LT	-	-
Estlink	FI-EE	159	16

Table A.6: Overview of the mean absolute error for the HVDC cables in the Nordic region with the reference day method. The table also shows the mean absolute error as a fraction of the average capacity in 2015