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Flow-Based Market Coupling in the Nordic Power Market

Implications for Power Generators in NO5

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Abstract

The aim of this thesis is to study the effect of the introduction of flow-based market coupling in the Nordic power market, with specific focus on the impact on power generators in the NO5 price area. The analysis is conducted using an optimization model of the Nordic synchronous area. In the model, flow-based market coupling is implemented based on the preliminary simulations and regulations by relevant authorities. The discussion is supported by relevant literature and theory on the topic, evaluating the currently chosen implementation strategies.

This thesis argues that generators in NO5 are expected to benefit from higher prices and more export opportunities after the introduction of flow-based market coupling. However, the net impact is more unclear. If the methodology is implemented without ensuring sufficient transparency in its design parameters, the uncertainty for generators increases.

Furthermore, this thesis finds that generators will be important in the transition process. The determination and calculation of design parameters will largely impact the efficiency of the flow-based model, and successful implementation depends on the contribution of generators. However, the parameters must be designed in a way that limits opportunistic behaviour of generators and other actors in the Nordic power market. Power regulators will have to play a crucial role on both a local and European level, facilitating transparency of processes and ensuring fair market conditions.

Keywords – Flow-Based Market Coupling, Nordic Power Market, NO5, Transmission Network, Electricity Prices, Power Generators, Cross-Border Interconnectors

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List of Abbreviations

AC	Alternating Current
AHC	Advanced Hybrid Coupling
ATC	Available Tranfer Capacity
CACM	Capacity Allocation and Congestion Management
CBCO	Critical Branch Critical Outage
CEE	Central Eastern Europe
CNE	Critical Network Element
CWE	Central Western Europe
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAV	Final Adjustment Values
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FRM	Flow Reliability Margin
GSK	Generation Shift Keys
GWh	Gigawatt Hours
HMC	Hybrid Market Coupling
HVDC	High Voltage Direct Current
kWh	Kilowatt Hours
MWh	Megawatt Hours
NEMO	Nominated Electricity Market Operator
NLP	Nonlinear Programming
NP	Net Position
NSL	NorthSeaLink
NTC	Net Transfer Capacity
NVE	Norwegian Energy Regulation Authority
NWE	North Western Europe
PCR	Price Coupling of Regions
PTDF	Power Transmission Distribution Factor
PX	Power Exchange
RAM	Remaining Available Margin
RSC	Regional Security Coordinator
SOB	Shared Order Books
TSO	Transmission System Operator
TWh	Terrawatt Hours
XBID	Cross-border Intraday Market Project

1 Introduction

The Nordic power market has during the last decades undergone substantial changes and is likely to continue to change rapidly during the years to come. During the 1990s, the Nordic power market was deregulated as one of the first markets in the world, and Nord Pool Spot was established as a common power exchange (Sutter, 2014). Since then, the European energy market has become ever more liberalized. After the establishment of the Energy Union in the European Union (EU) in 2015, the EU has been facilitating a free flow of energy through the EU in order to achieve a fully integrated internal energy market (European Commission, 2015).

Several factors will play a role in reaching the EU's goal, such as investments in grid development and increased interconnection capacity. Another possible solution is to increase the efficiency of the existing power grid by altering the market coupling algorithm in the day-ahead market. In 2015, the European Commission decided that European power exchanges must implement Flow-Based Market Coupling (FBMC) if it cannot be proved that another method provides a more efficient market clearing (European Commission, 2015). In May 2015, FBMC was implemented in the Central Western European (CWE) region as the first in the world (Van den Bergh et al., 2016).

Three years later, in July 2018, the Nordic Transmission System Operators (TSOs) approved FBMC as the new market clearing algorithm for the Nordic day-ahead market. The TSOs concluded, after extensive market simulations, that FBMC provides more available trade opportunities in the market. The physical grid capacity in the Nordics will also be utilized in a more flexible and economic way, according to the TSOs. The new algorithm will replace the current Net Transfer Capacity (NTC) method in the spot market during the fall of 2021, provided that all tests are successful. (Statnett, 2019).

Flow-based market coupling is distinct from the NTC model in several ways. In both algorithms, prices are calculated with the objective to maximize socioeconomic benefit in the market. The constraints of the two optimization problems, however, are different. The NTC model represents the aggregation of all expected network limitations with one single value that is determined ex-ante market clearing (Schavemaker et al., 2008). However, the Alternating Current (AC) power flows between two elements in a power grid are determined by Kirchhoff's laws as well as the thermal limits of the transmission lines. The physical power flows are therefore often not similar to the commercial flows simulated in the NTC model. In flow-based market coupling, the physical laws of the network are partly implemented in the market coupling algorithm.

Although FBMC is constructed to represent the physical power flows more accurately, it is not given that it provides a market clearing solution superior to the NTC method (Bjørndal et al., 2018a). If the simulated capacity domain is too restrictive, it limits the effective utilization of the power grid. If it is too loosely defined, on the other hand, it can lead to grid overloads. When the grid is accurately simulated, economic efficiency is achieved through the completion of optimal power transfer, lower safety margins and a lesser need for costly remedial actions (Aguado et al., 2012). These are issues that will be addressed in this thesis.

The aim for this thesis is to evaluate how the the future transition to flow-based market coupling will affect the Nordic power markets. A particular emphasis is placed on the NO5 bidding zone, including how FBMC will affect prices and power generators in NO5. In order to address these questions, an optimization model for the Nordic power market is constructed. Furthermore, relevant research and literature is explored, in addition to TSO reports that explain how FBMC will be implemented in the Nordics. The focus is to address differences from the current model as well as expected future changes in the power market and its impact with flow-based market coupling.

Data from the flow-based market coupling simulations conducted by the Nordic RSC, as well as market data from Nord Pool, is used to build a flow-based market coupling model. Furthermore, the effect of additional transport capacity through planned cross-border interconnectors is analyzed in order to evaluate the impact of these cables in an FBMC context. Additionally, the distribution of price differences and congestion over time is analyzed in order to identify how often the changes analyzed could be expected. Finally, this thesis explores how regulators and generators impact the outcome of the flow-based market coupling through definition of parameters and transparency in methodologies. Thus, the problem statement for this thesis is as follows:

How does the planned implementation of Flow-Based Market Coupling affect power generators in the NO5 price area?

The topic of this thesis is of importance due to several reasons. Firstly, the implementation of flow-based market coupling in the Nordic power market is already decided, and implementation will occur within the next few years of writing this thesis. It is therefore a topic of high practical relevance. Secondly, the power market is fundamental for many different stakeholders in the Nordics, from private households to large industry actors. An effective power market is important for society as a whole, and a difference in power prices can constitute significant costs for several market players. Thirdly, the topic of flow-based market coupling is relatively unexplored in a Nordic market context. As FBMC must be implemented on a market-to-market basis, it is important to study the topic for specific markets. Furthermore, to the best of our knowledge, no other studies have explored the impact of flow-based market coupling on the NO5 price area.

The rest of this thesis is organized as follows. Chapter 2 describes the fundamental principles, characteristics and actors of the Nordic power market, as well as the status of flow-based market coupling implementation in Europe. Chapter 3 provides an overview over existing literature on the flow-based market coupling methodology and its impact. Chapter 4 explains the theoretical and technical concepts that are relevant for FBMC in general and this thesis in particular. Chapter 5 presents an overview over the methodology and data used to construct the optimization model applied in this thesis. Chapter 6 is an overview over the most central findings in the analysis conducted, including how various cross-border interconnectors can affect the power prices in the Nordics and in NO5. Chapter 7 discusses the findings with a particular emphasis on how FBMC will affect power generators in NO5. Furthermore, the implications of flow-based design parameters on NO5 are discussed. Lastly, chapter 8 contributes with the concluding remarks, summarizing the study's main findings and presenting suggestions for future research.

2 Background

This chapter will serve as a background for this thesis and explain the main features, concepts and characteristics of the Nordic power market, as well as relevant related topics. Section 2.1 describes the Nordic power market, including how the Nordic TSOs operate, the Nord Pool Group, the Elspot market, and relevant energy policies. Section 2.2 discusses the key features of congestion management and provides a historical backdrop of the implementation of flow-based market coupling in Europe and in the Nordics.

A more detailed explanation of congestion management and how it is handled in the ATC/NTC and FBMC methods will be further explained in chapter 4. Lastly, section 2.3 provides an overview over the future development of the Nordic power market.

2.1 The Nordic power market

2.1.1 Main actors in the electricity market

Electricity markets are complex and require a large number of interconnected parts and a large number of people, working together as a coordinated system (Biggar and Hesamzadeh, 2014). The electricity markets in Europe combine the EU, national and regional politics and regulation with principles from physics and economics. To manage this market, four main actors can be identified (Boury, 2015).

Firstly, electricity generators and retail companies are the market players that deliver bids and offers on the market. Statkraft is the largest power generator in Norway and fully owned by the Norwegian government (Statkraft, 2019). The generators and retailers represent the first and fourth step in the electricity delivery process of generation, transmission, distribution and retailing, respectively.

Secondly, regulators monitor and control the market events without directly being involved in the electricity market processes (Boury, 2015). Their mandate is to ensure that laws and regulations are enforced and that no market participants are treated unfairly. The Nordic Regional Security Coordinator (RSC) is an example of a power regulator and will be further explained in section 2.1.3.

Thirdly, Power Exchanges (PX) are the organizers of the electricity market in a certain area (Boury, 2015). They clear the market by collecting all bids in a market, as well as determining allowable trade between TSOs. Nord Pool is the power exchange in the Nordic region and will be elaborated on in the following sub section.

Lastly, a Transmission System Operator (TSO) is the owner and operator of a high-voltage grid and responsible for the security of supply in its country. (Nord Pool Spot, 2014). The TSO balances the grid and ensures that the network is not overloaded. The four Nordic (mainland) TSOs are Statnett (Norway), EnergiNet (Denmark), Svenska Kraftnät (Sweden) and Fingrid (Finland). Ensuring a balance in the grid implies balancing production and consumption and is measured in grid frequency. In Europe, this target frequency is 50 cycles per second (Hertz) and must be kept within a 2% range in order to be within normal operational limits (Statnett, 2019).

2.1.2 Nord Pool

The Nordic power market is often defined as the Nord Pool area. Nord Pool is the power exchange (PX) of the Nordic region and serves as the common market place for electricity trade in the day-ahead market, Elspot, and the intraday market, Elbas. The region consists of the Nordic and Baltic countries; Norway, Denmark, Sweden, Finland, Estonia, Latvia and Lithuania (Sutter, 2014). The Nordic countries in the Nord Pool area are often referred to as "The Nordic synchronous area".

The concept of a common Nordic power exchange is relatively new, and the market has undergone substantial changes the last few decades. In 1991, the Norwegian power market was deregulated, and since then all of the Nordic countries have liberalized their electricity markets, allowing competition on both trading and production (Sutter, 2014). In several of the countries, grid and production were split into two separate entities, such as “Statnett” and “Statkraft” in Norway. The intention of the liberalization was largely to improve competition in order to incentivise a more efficient utilization of production resources, and in turn, lower production costs and consumer prices (Jegleim, 2015).

In 1993 the Nord Pool Spot was established by the Norwegian TSO Statnett as “Statnett Marked” (Sutter, 2014). When Sweden joined the collaboration in 1996, it was rebranded to Nord Pool as the world’s first international power market. After Finland and Denmark joined in 1998 and 2000, respectively, the Nordic mainland power market was entirely integrated. The three Baltic countries were included as bidding zones in 2010, 2012 and 2014, respectively. (Sutter, 2014). This thesis will focus on Elspot, the day-ahead market, as it is more central to the model and analysis than the intraday market.

The main function of the Nord Pool Spot is to ensure liquidity, transparency and security of supply in the power markets, hereunder providing accurate information to all of the market players and equal access to all parties willing to trade power. In this regard, they serve as a counter party, guaranteeing for all trades. 380 companies from 20 countries participate in the trade conducted through Nord Pool, and in 2017, the total trade was 512 TWh (Nord Pool Group, 2019a).

Nord Pool is also considered a Nominated Electricity Market Operator (NEMO) as the only one in the Nordic Power market (Nord Pool Group, 2019a). However, during 2019, other PXs can apply to be a NEMO, which will involve Shared Order Books (SOB) and a more fragmented ownership to power data and bid curves (Nord Pool Group, 2019e). In June 2018 Nord Pool formed, together with the PXs in Europe and 11 European TSOs, the joint initiative Cross-border Intraday Market Project (XBID) (Nord Pool Spot, 2019).

XBID creates a single European intraday market that enables continuous cross-border trade across several of the European countries, where submitted orders are centralised in one shared order book and the intraday cross-border capacities are made available by the TSOs. The solution is expected to increase the liquidity and efficiency of the intraday markets, since orders can be matched by any participating country (Nord Pool Spot, 2019). However, Nordic RSC (2019c) points out that XBID does not yet support the FB approach and that this is a main obstacle for the implementation of target capacity calculation in flow-based market coupling.

2.1.3 The Nordic RSC

The Nordic Regional Security Coordinator (RSC) was founded in 2018 and is a collaboration between the four Transmission System Operators (TSOs) in the Nordic Nord Pool region (Nordic RSC, 2019a). The RSC was created as a response to EU regulations with the purpose of coordinating and monitoring different parts of the European power grid (European Network of Transmission System Operators, 2015). A central task is to retrieve the grid models for every country and collect it to a Common Grid Model for the entire region (Statnett, 2017).

According to the European Network of Transmission System Operators for Electricity (ENTSO-E), an RSC benefits the consumers in a power market because it increases efficiency in the system operation and minimises risks of events, such as major blackouts (European Network of Transmission System Operators, 2015). Additionally, the enhanced TSO coordination can limit the need for costly redispatching in the market, for example through a common approach to operational planning and market integration. The ENTSO-E itself represents 43 TSOs from 36 countries across Europe and was given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising the gas and electricity markets in the EU. Its mandate include policy making, technical cooperation between TSOs, the development of European network plans, facilitating, as well as establishing RSCs (European Network of Transmission System Operators, 2015).

Furthermore, the Nordic RSC is responsible for simulating the implementation of flow-based market coupling in the Nordics (Nordic RSC, 2019b). Hence, the Nordic RSC collaboration is of great significance to the Nordic power market and will, due to its mandate, be a significant player in the introduction of flow-based market coupling in the Nordics (Nordic RSC, 2019c).

2.1.4 The day-ahead Elspot market

The majority of the traded volume in the Nordic and Baltic region, 84% in 2014, is settled in Elspot, the day-ahead market (Sutter, 2014). Elspot is Europe's most liquid day-ahead market and calculates prices in an auction based on supply, demand and transmission capacity in the bidding zones. The most relevant steps in the Elspot procedure for a given day is illustrated in figure 2.1 from (Sutter, 2014).

Figure 2.1: The Nordic Elspot market clearing procedure at the day-ahead, D-1 (Sutter, 2014).

Day D represents the day of the actual power delivery for in which the prices are calculated. Before 10.00 CET on the day before the actual delivery, D-1, TSOs publish the power transmission capacities to each bidding area. By 12.00 on D-1, all market participants must have placed their buy and sell bids based on their expectations for consumption and production, respectively. An algorithm will then construct the aggregate supply and demand curves from the bids for a particular bid zone. The prices are in turn calculated day-ahead for the 24 hours of the upcoming day, day D. The auction closes at 12.00 on D-1, and at 12.45 the system and area prices for day D are announced by Nord Pool. The intersection of the supply and demand curves determine the hourly system price as illustrated in figure 2.2. (Sutter, 2014).

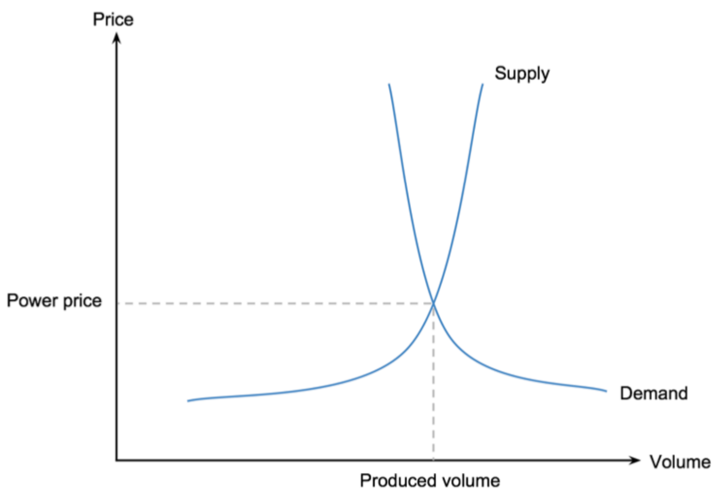

Figure 2.2: The Nordic Elspot market equilibrium, general illustration.

There are three types of bids at Nord Pool Spot. Hourly bids trade for individual hours, with price and volume given separately for each hour (Nordeng, 2016). They are the most common type of bids and at the core of this thesis. Block bids are all-or-nothing orders, where bids are gived for a whole block of hours (Bjørndal et al., 2013). Lastly, flexible hourly bids are sell bids for hours with highest prices.

Although the majority of the trades occur on the Elspot market, there may occur changes or incidents between the closing of Elspot at 12.00 CET and the day of the actual power trade (Nord Pool Spot, 2014). In Elbas, the intraday market, power can be traded up until one hour before the power is delivered (Sutter, 2014). However, as the intraday market is not the emphasis of this thesis, the Elbas market will not be explained in detail.

2.1.5 Principles of congestion management in the Elspot market clearing

The concept of congestion in a power grid occurs when the transmission capacity of at least one transmission line is binding, thus restricting the power transmission between regions (Boury, 2015). Congestion management is therefore the process or systems in place to avoid congestion and ensure cost-optimal power dispatch when accounting for these constraints. In this paper, a particular emphasis will be given on zonal congestion management. This can be done in two ways, either passively through redispatching, or by incorporating the constraints in the market coupling process (Boury, 2015). Marien et al. (2013) distinguishes between commercial and physical congestion. A commercial congestion occurs when the capacity made available for the TSOs ex-ante for a given time frame is not sufficient to cover all of the market trade requests. A physical congestion occurs real time in a network situation where the the system is at risk and is solved by congestion relief (Marien et al., 2013).

In the section above, the Elspot trading model is explained as a tool to calculate the so-called system price. This is a purely theoretical price for the entire Elspot region and would be the price if there were no bottlenecks in the grid (Nord Pool Spot, 2014). However, bottlenecks can occur in a power grid when the market requests more capacity than what is available one the line (Boury, 2015). The transmission lines will in such cases be overloaded and outages can occur. Because of this, the Nord Pool Spot area is divided into 15 bidding areas (Nord Pool Group, 2019b), and the division into several price zones partly takes the grid constraints into account in the day-ahead market (Bjørndal et al., 2013).

The TSO of each country determines how the bidding zone configuration will be in their country. Norway is divided into five zones, Sweden in four, and Denmark in two separate bidding areas. Finland, Estonia, Latvia and Lithuania are all one single bidding area per respective country. The division of areas are selected on the basis of where long lasting bottlenecks are expected to occur (Statnett, 2013). Despite there being different price zones, the day-ahead prices are often relatively similar due to their close interconnectedness. (Nord Pool Spot, 2014). The Elspot bidding zone configuration is illustrated in figure 2.3.

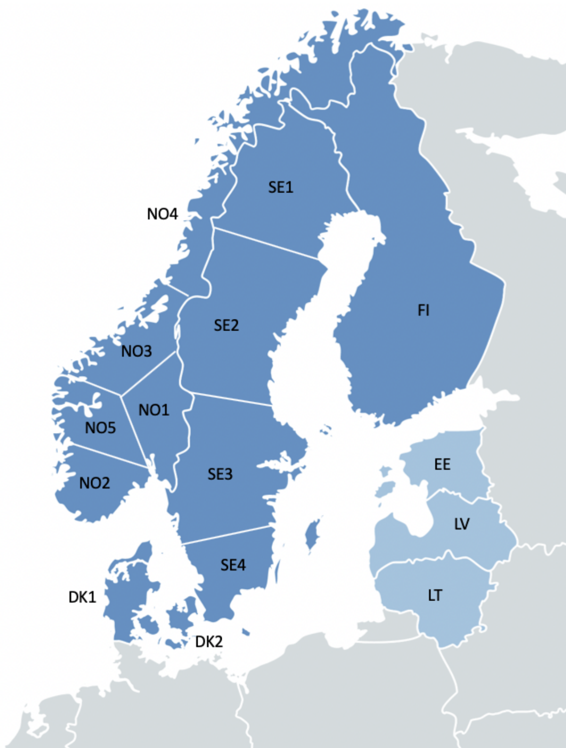

Figure 2.3: The Nord Pool bidding zone configuration (Based on Nord Pool Group (2019b)).

Depending on the available transmission capacity in the grid, the spot markets in the different bidding areas are integrated to maximize the overall social welfare in the markets. When transfer capacity between two zones is limited, some areas can have a surplus of power while others have a power deficit, causing a price difference between the areas (Marien et al., 2013). The Elspot market is an implicit auction, meaning that the available transmission capacity is used to level out price differences (Nordic Energy Regulators, 2007). Hence, the market participants do not have to make explicit reservations on transmission capacity. The concept of price differences in two bidding areas is illustrated in figure 2.4.

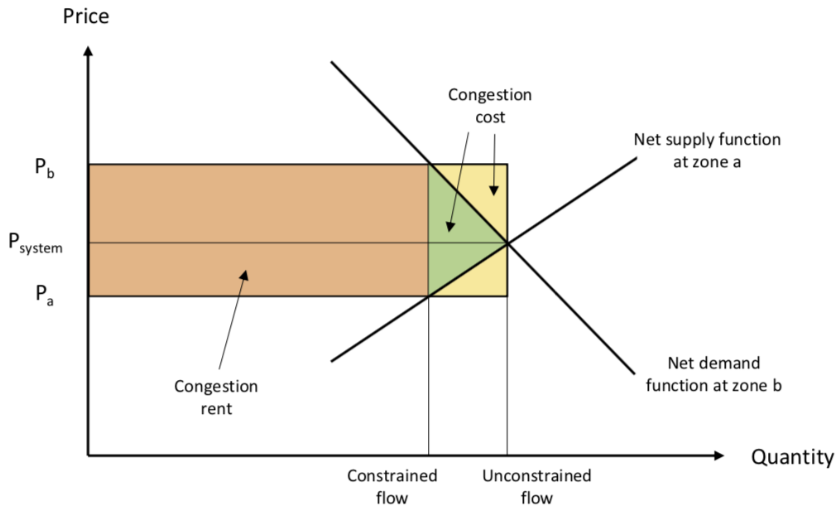

Figure 2.4: Constrained and unconstrained power flow in an example with two zones. Based on unpublished lecture notes by Bjørndal (2018).

The figure illustrates two biding areas, area a and area b, with two different price solutions in a given operating hour. Zone a is a net exporter to zone b, while zone b is a net importer from zone a. In the event of zero congestion, the clearing price will equal the system price, P_{system}. However, if there is a congestion on a connection linking the two zones, there will be a price difference between the zones. In this case, the price in the net supplying zone is P_a and the price in the net demanding zone is P_b, which is higher than both P_a and P_{system}.

Figure 2.4 also illustrates how congestion leads to a loss of total socioeconomic benefit due to the social and relief costs of congestion. These are the costs due to the lack of trading the optimal power amount, as well as costs related to remedial actions in order to match supply and demand. (Bjørndal, 2018).

The example above illustrates the benefit of interconnected power markets and the value of keeping bottlenecks and congestion at a minimum. The concept occurs in both flow-based and net transfer capacity models. The orange field represents the congestion rent and will be discussed in the upcoming section.

2.1.6 TSOs and congestion rent

In the example illustrated in figure 2.4, congestion leads to a price difference between two zones. This price difference multiplied by the energy exchanged between the two zones is the congestion rent and is illustrated by the orange field in figure 2.4 (Marien et al., 2013). Congestion rent is a surplus originating from price divergence between two zones and is collected at the location of the trade, either by the PX or the TSOs (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). In the Nordic countries, the rent is collected by the individual TSOs and distributed between the TSOs according to established agreements. In Norway, the congestion rent is part of a regulated revenue, and will not increase the revenue of Statnett. The rent is normally used for grid infrastructure development and maintenance (Nordic Energy Regulators, 2007). The congestion rent (CR) can be calculated as:

$$CR = F_{s,d} * (P_d - P_s) \tag{2.1}$$

Where
P_s = price in surplus area,
P_d = price in deficit area and
$F_{s,d}$ = power transmitted between surplus and deficit area

Normally, power flows will intuitively flow from the surplus area to the deficit area. In a flow-based model, however, so-called non-intuitive flows may occur. In such cases, power can flow from a high price area to a low price area, leading to price differences between two areas where there is free transfer capacity (Vlachos and Biskas, 2015). Non-intuitive flows occur because the flow is not only restricted by transfer capacities, but also physical properties of the system (Nordic RSC, 2019c). It is possible that the flow from a high price area to a low price area frees capacity in a critical branch, and that this creates a higher utility than an intuitive flow. From equation 2.1, one can see that non-intuitive flows leads to negative congestion rent. (Vlachos and Biskas, 2015).

As congestion rent is omitted in the model used for the analyses in this thesis, the concept will not be further elaborated on.

2.1.7 Price coupling of regions - EUPHEMIA

EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) is the current price coupling algorithm used by the NEMOs in Europe to operate the day-ahead market (Nordic RSC, 2019c). Eight European PXs oversee the project: EPEX SPOT, GME, HEnEx, Nord Pool, OMIE, OPCOM, OTE and TGE (Nord Pool Group, 2019f). EUPHEMIA was used for the first time on the 4th of February 2014 when the North Western Europe (NWE) was coupled with South-Western Europe. Several other European markets were later successfully connected. (EPEX Spot, 2016).

The EUPHEMIA Price Coupling of Regions (PCR) is based on three main principles (Nord Pool Group, 2019f). Firstly, it should be a single common algorithm for fair and transparent determination of day-ahead electricity prices and net positions of bidding in Europe. The purpose of the algorithm is to optimize overall welfare and increase transparency.

The second principle of the EUPHEMIA PCR is robustness of the process, meaning that sharing of data should be decentralized (Nord Pool Group, 2019f). Thirdly, there should be an individual power exchange accountability. This principle implies that the PCR system allows for the exchange of anonymized orders and grid constraints among the individual PXs in all price zones. The optimization algorithm returns prices, volumes, net positions and flows on each interconnection for a given time period in the day-ahead market (EPEX Spot, 2016).

The EUPHEMIA algorithm provides a fundamental background for the further work and analysis in this thesis. For a more detailed description on the separate stages of the optimization model and practical implications, see Nord Pool Group (2019f).

2.1.8 Key features of the Norwegian power market

The Norwegian electricity market is characterized by the dominance of hydropower in the power mix. In September 2019, 10.179 GWh of the Norwegian electricity production originated from hydropower, representing 93,0% of the total monthly production of 10.949 GWh (Statistics Norway, 2019). On a yearly basis, hydropower accounted for 95,8% in 2017. Thermal power made up only 2,3% of the power mix in 2017, significantly less than in most countries. The remaining 1.9% of the production came from wind power originating from 33 wind farms. Hence, Norway has the highest share of electricity produced from renewable sources in Europe, as well as the lowest emissions from the power sector (Energy Facts Norway, 2019).

In 2017, Norway was a net exporter of power, exporting 21.276 GWh and importing 6.112 GWh, with a total net consumption of 124.830 GWh. From this consumption, 44,4% went to industrial activity, 21,3% was consumed in the service sector, and 34,3% of the demand originated from farming and private household consumption. (Statistics Norway, 2019).

In Norway, the majority of hydropower production, and hence the total power production, comes from hydropower reservoirs with great storage capacities. 800 reservoirs can store water to the equivalent of approximately 86.500 GWh - half of Europe's total reservoir capacity. This allows for the reservoirs to be drained when the need for power is high, and filled when the demand is lower. Although electricity generally cannot be stored, the reservoirs act as enormous natural batteries. Thermal power, on the other hand, is notably more costly to regulate in terms of short term production capacity. The flexibility of the Norwegian power mix, compared to the other countries in the Nord Pool area and in Europe in general, allows us to balance variation in supply and demand with the connected regions. (Norwegian Energy Regulatory Authority, 2019d).

2.1.8.1 The NO5 bidding zone

The bidding zone NO5 covers the western part of Norway, and borders to the NO3 area in the north, NO1 in east, and the NO2 zone in the south. It consists of the middle and northern part of Hordaland, Sogn og Fjordande south of the Sognefjord and Inner Sogn. BKK, Norway's fifth largest power producer, is also the sole provider of power grids in the region through governmental concessions. BKK is owned by Statkraft and 17 counties (kommuner) in western Norway, and the profits of BKK are distributed to these owners. The NO5 region is defined by the following interconnectors. (BKK, 2019).

Capacity	Interconnector	Connected zone
420 kV	Sogndal-Høyanger	NO3
132 kV	Grindsdalen-Mel	NO3
300 kV	Mauranger-Blåfalli	NO2
420 kV	Dagali-Ringerike	NO1
420 kV	Nore1-Sylling	NO1
420 kV	Usta-Ådal	NO1
300 kV	Nes-Sogn	NO1
300 kV	Hemsil 2-Sogn	NO1
132 kV	Flå-Sandum	NO1

Table 2.1: NO5 interconnectors (Statnett, 2019).

The average day-ahead power price in the NO5 zone was 43,05, 28,84 and 24,91 EUR/MWh in 2018, 2017 and 2016, respectively. The system price in the respective years was 43,99, 29,41 and 26,91 EUR/MWh (Nord Pool Group, 2019c). In a normal production year in NO5, reservoir power accounts for 24 TWh, large river-based hydropower (>10MW) for 4 TWh, and small river-based hydropower (<10MW) for 2 TWh. This represents around 21% of the total power production in Norway (NOU 2019: 16., 2019). The majority of the production comes from large reservoir hydro power plants in the eastern part of the NO5 region, such as the Hallingdal and Aurland area (Norwegian Energy Regulatory Authority, 2019e). Aurland I and Sy-Sima are both located in east in NO5, two of the largest power plants in Norway with a total yearly production capacity of 2 508,3 GWh and 2 158,2 GWh, respectively. In this very area, however, population and consumption is relatively scarce. In the western part of the region and around the Bergen area, on the other hand, consumption and production is more balanced due to power demand from both industry production and private household consumption (Norwegian Energy Regulatory Authority, 2019e).

2.2 History and current status of FBMC

This section will provide a brief overview of flow-based market coupling and its implementation status in European electricity markets. In a Commission Regulation 2015/1222 by the European Union Commission on Capacity Allocation and Congestion Management (CACM) in July 2015, the EU outlines the work towards "minimum harmonised rules for the ultimately single day-ahead and intraday coupling, in order to provide a clear legal framework for an efficient and modern capacity allocation and congestion management system" (European Commission, 2015). The purpose of the integration towards a single liberalized European electricity market is to ensure more efficient use of the network and increased competition.

The European Commission (2015) furthermore determined that the flow-based model should be the primary approach in the day-ahead and intraday markets where there exists a high degree of interdependence on the cross-zonal capacity between bidding zones. However, the implementation of flow-based market coupling should only occur if the market participants are well prepared and sufficiently consulted. In other words, flow-based market coupling must be implemented if it cannot be proved that another method provides a more efficient market clearing. (European Commission, 2015).

2.2.1 FBMC implementation in Central Western Europe

In June 2007, the relevant actors of the electricity market in the Central Western Europe (CWE) region signed a memorandum declaring their plans to implement FBMC in the CWE region (CREG, 2007). The region consists of Belgium, the Netherlands, France, Germany, Luxembourg and Austria. In May 2015, FBMC was launched as the cross-border capacity calculation method after after eight years of developing and evaluating the methodology (Van den Bergh et al., 2016). In the period 2013 to 2014, parallel simulations of the ATC and FBMC methods were conducted. The results of the simulations are further discussed in chapter 3. The successful implementation of FMBC in the CWE region serves as an example for the rest of the European electricity markets.

2.2.2 FBMC implementation in the Nordics

In 2012, the Nordic TSOs began evaluating FBMC as a market clearing method as later required by CACM (Statnett, 2017). In 2017, an offline parallel run was initiated. The simulations utilize EUPHEMIA to calculate NTC and FBMC market clearing on a weekly basis and will continue throughout 2020. After successful simulations, the Nordic TSOs approved FBMC as a new market clearing algorithm in July 2018 (Statnett, 2019). Their goal is to implement the flow-based method in the spot market during the fall of 2021.

The results of the simulations conducted in the Nordics are also presented in chapter 3.

2.3 Structural changes in the Nordic power market

2.3.1 The status and impact of cross-border interconnectors

A cross-border interconnector is a transmission cable that connects the electricity trade between two separate power markets (Turvey, 2006). As previously discussed in section 4.2.1, the integration of power markets can lead to a better resource utilization (Statnett, 2017), and the connection can impact the market clearing solution in a given region (Nord Pool Spot, 2014).

Furthermore, Norway has a large degree of flexible hydroelectric power in the power mix (Norwegian Energy Regulatory Authority, 2019c). More available cross border transfer capacity allows for a greater utilization of the hydro reservoirs, allowing for reserve capacity to be available where it is needed (Statnett, 2017). This flexibility in the power market is important for the market clearing in the power market and the balance of the system operation. Additionally, larger cross-border transfer capacity provides specific value creation opportunities for Norway by capitalizing on the flexibility of the stored capacity in the hydro reservoirs (Statnett, 2017).

The existing and future cross-border High Voltage Direct Current (HVDC) interconnectors in the Nordics, including the planned NorthConnect cable, are illustrated in figure 2.5, from European Network of Transmission System Operators (2019).

Figure 2.5: Current, future and planned cross-border HVDC interconnectors in the Nordics (European Network of Transmission System Operators, 2019).

NorthConnect, North Sea Link and NordLink are all cables under construction between Norway and the rest of Europe. NorthConnect is a planned 650 km long subsea cable between Western Norway and Scotland and is under consideration (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). NordLink is currently under construction and will be completed in 2021. The HVDC subsea interconnector will stretch from NO2 in Norway to Northern Germany and have a capacity of 1400 MW (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019).

NorthSeaLink (NSL) is, similar to NordLink, also a 1400 MW HVDC subsea interconnector and will connect NO2 to the UK (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). NordLink and NSL will increase Norway's interconnector capacity to about 9000 MW (Hernes and Bruvik, 2018) and will according to EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2019) improve security of demand in Europe and facilitate for renewable energy production. There has also been discussions on a new HVDC interconnector between NO5 and Scotland, NorthConnect, but this is still in the planning phase. If built, it will also have a total capacity of 1400 MW (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019).

As the Nordic power market becomes increasingly integrated, FBMC will gain importance as it is expected to allow the market participants to use transmission capacities closer to their physical limits and provides for a better power network utilization (Rious and Dessante, 2009).

2.3.2 The Nordic power mix

In addition to developments in grid infrastructure and cross-border interconnectors, the Nordic power market is likely to undergo significant changes in the upcoming years (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). A comprehensive white paper issued by the Norwegian Ministry of Petroleum and Energy in 2019 outlines the projected scenario of Norway, the Nordics and Europe in general. The EU has decided to reduce climate emissions by 40% in 2030 compared to the levels in 1990. Their goal is for renewable energy to make up 27% of the power mix in 2030. Many countries have also set their own targets for reducing their production of coal and nuclear power, such as for example Germany. EU countries are also investing heavily in wind and solar power, and renewable energy capacity has increased by 68% from 2013 to 2019. (Ministry of Petroleum and Energy, 2016).

For the Nordic region, power demand is expected to increase from 403 TWh in 2020 to 461 TWh in 2040, according to (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). Sweden and Denmark have set the goal to reach 100% renewable energy production by 2040, and the Finish government aims for the country to be carbon neutral by 2035 (Ministry of Petroleum and Energy, 2016). Cost reductions in renewable energy, such as solar and wind power, have been a growth lever for the rapid development (Norwegian Energy Regulatory Authority, 2019c). Moreover, Nordic nuclear power production will be significantly reduced in the upcoming years due to few development projects and the decommissioning of nuclear power plants in several countries, including Sweden (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019).

As non-flexible renewable energy production becomes a larger part of the Nordic power mix, the power system will be even more weather dependent than it is today, which might foster larger variations in power prices (Norwegian Energy Regulatory Authority, 2019c). However, this effect is mitigated by a closer connection between price zones. The Norwegian Energy Regulatory Authority (2019c) also points to improved future battery technologies as a factor for reduced short term price differences as power can be stored in power surplus periods and used in deficit periods.

Norwegian Energy Regulatory Authority (2019c) furthermore addresses the projected price differences between the Nordic countries. Towards 2030, the increased production of wind power in Sweden will lead to lower Swedish power prices, that will again contribute to lower power prices in mid- and northern Norway. Due to limited grid capacity in Norway, the price differences between northern and southern Norway will increase. Northern Norway has a good basis for wind power development, but a projected large power surplus in the region and limitations in the grid will largely isolate the effect of lower power prices to that very region. (Norwegian Energy Regulatory Authority, 2019c).

Due to the extensive generation plans, the Nordic region is expected to remain a net exporter of power in 2040, provided a normal year scenario. An expected Nordic power production surplus will strengthen the Nordics in the years to come, as the weather becomes an increasingly more important factor for the power situation (Norwegian Energy Regulatory Authority, 2019c).

3 Literature review

3.1 Flow-based market coupling

This chapter will provide an overview over existing literature on the subject of flow-based market coupling and represents a theoretical basis for this thesis. There is a relatively large body of literature documenting the theory and methodology of flow-based market coupling, while methods for implementation and uncertainty reduction are currently being explored. In addition to academic work on the topic, technical reports by relevant market actors will be particularly emphasized.

The concept of flow-based market coupling was first outlined in detail by TSOs in the Central Western European (CWE) region by Schavemaker et al. (2008) with the purpose of guaranteeing the network security with a maximum amount of transparency as incorporated in a regional market coupling. This subject matter is further elaborated in Aguado et al. (2012), where CWE TSOs present the development in flow-based capacity calculations. Aguado et al. (2012) conclude that FB enables a higher capacity utilization than the ATC mechanism, thus leading to higher social welfare and price convergence. The simulations take remedial actions, such as redispatching, into account as they can make up a significant cost and a large share of the total import/export capacities of an area (Aguado et al., 2012).

Aguado et al. (2012) furthermore describe how a transition from ATC to FBMC in the CWE region will lead to a major change for the market participants in terms of daily operational processes for the TSOs, tools to determine daily capacities, power exchanges and the market clearing algorithm. Van den Bergh et al. (2016) provides a description of the FBMC methodology, including the calculation methods of zonal PTDFs and Remaining Available Margin (RAM), which will be thoroughly explained in section 4.2.5.

Other studies have looked into how different design parameters influence the effectiveness of the FBMC mechanism, with particular emphasis on the CWE and CEE regions. Marien et al. (2013) analyze the impacts of Flow Reliability Margins (FRM) and Generation Shift Keys (GSK) on FBMC through a simplified model. They find that smaller and more numerous zones lead to lower FRM and reduced uncertainty, and that the choice of

GSKs impact the prices provided with the FBMC methodology. The article explains how GSKs need to correspond to the best forecast made by a TSO in order for FBMC to work effectively. This is challenging due to a circular problem; ex post GSK values depend on price levels while ex ante GSKs impact the prices. A suggested solution to this issue is adequate monitoring and transparency of TSO behaviour (Marien et al., 2013). The topic of optimal GSK calculation is further explained by Van den Bergh and Delarue (2015) in their paper *An Improved Method to Calculate Generation Shift Keys*.

Van den Bergh et al. (2016) also concludes that FBMC provides more transmission capacity and thus higher social welfare. However, the effect and relevance of redispatch and congestion relief due to network congestion, which might lead to additional costs for the end consumer (Bjørndal et al., 2018b), is not mentioned in the paper. Furthermore, Van den Bergh et al. (2016) explain how FBMC may be considered more transparent than the ATC method from a regulatory perspective, but that it "can be questioned" from a markets player's perspective due to the unclear capacity signals represented by the FBMC parameters. Three policy recommendations are also provided in Van den Bergh et al. (2016): i) The expected benefits of FBMC should be empirically evaluated based on historical market data, ii) coordination among TSOs should be further improved, and iii) smaller market zones provides a better representation of the physical characteristics of the power grid. These findings are largely in line with the recommendations presented in Marien et al. (2013).

In addition to the abovementioned policy recommendations for successful implementation, other aspects have been discussed by various researchers on the field. Bjørndal et al. (2018a) discuss the importance of monitoring non-critical branches and to which extent the FBMC model relieves the congestion on the CNEs. Moreover, the article explains how network limitations in the FBMC model might lead to more redispatching at the expense of the end consumers. They find that it is hard to identify the CNEs only based on the zonal PTDF matrix, leading to inefficient CNE selection by the TSOs. As opposed to a large amount of previous literature on the subject, Bjørndal et al. (2018b) conclude that FBMC does not necessarily represents a better congestion relief and resource utilization within the network compared to the ATC method.

In addition, Bjørndal et al. (2018a) argue that the advantages of the flow-based model might increase as more renewable energy sources continue to make up a greater portion of the Nordic and European power mix. More variable non-flexible power sources demand a more accurate monitoring of power flows as the power often is produced in areas with little consumption. The need to transport power for longer distances may create congestion that is likely to be solved in a more efficient manner in the FBMC method, compared to ATC calculation (Leuthold et al., 2008).

Another important factor for the performance of network flow models is how the bidding zones are configured. By simulating different bidding zone configurations in the IEEE RTS 24-bus test system comparing the ATC model to the FBMC model, Bjørndal et al. (2018b) find that redispatching costs can be reduced by almost 23%. However, this is under the circumstance of full cooperation between the TSOs. Without any cooperation, the redispatching cost increases by up to 33%. This is in line with the findings of Van den Bergh et al. (2016), where close cooperation between TSOs is encouraged. Furthermore, Bjørndal et al. (2018b) explain how a nodal pricing model leads to lower redispatching costs than both the ATC and FBMC models.

The importance of price bidding zone configurations for FBMC effectiveness is further discussed in Voswinkel et al. (2019). In an analysis comparing the performance of the FBMC method to the theoretically optimal solution, i.e. a nodal pricing model, they find that FBMC realizes around 87% of the total possible welfare gains under ideal conditions with unlimited trade. This estimate is based on the case of CWE and includes the costs or redispatching. Since the case is based on a theoretical optimum, the simulated costs will not necessarily be representative for real-life cases. What is interesting, however, is the effect of intra-zonal bottlenecks in the simulation results. With the presence of intra-zonal bottlenecks, the realized welfare gains are reduced to 59%. The reason is that intra-zonal trade is not controlled by the market clearing process, the authors explain. Furthermore, they find that issues related to regulatory changes, GSK estimation and forecast errors are less prominent than the relevance of intra-zonal bottlenecks, suggesting that price zone reconfiguration or grid expansion should be considered in such cases. (Voswinkel et al., 2019).

As explained in this section, much of the literature on FBMC is positive to the method, explaining how it is likely to offer larger trade capacity between the bid areas, smaller price differences and a total increase in social surplus compared to the NTC model. However, flow-based calculation does not come without a cost, and the issues related to remedial actions, increased market complexity and the lack of transparency might dampen the benefits of the FBMC methodology. The challenges and limitations of flow-based market coupling should be further explored in a Nordic context.

3.2 FBMC in the Nordics

As this paper investigates the effect of the FBMC methodology on the market clearing in the Nord Pool area, however, it is natural to examine the theoretical work done in a Nordic and Norwegian market context.

In 2013, SINTEF Energi published the results of a comparative simulation on the ATC and FB models on behalf of Statnett. The general findings are that FBMC leads to a higher socioeconomic surplus and a more efficient use of the transmission grid compared to the ATC model (Helseth, 2013). In the analysis, a combination of the grid models “Samlast” model and “Samnett” was used, which again is based on the stochastic market model “Samkjøringsmodellen” (EMPS) for long-term and medium-term scheduling of hydrothermal power system operation (Helseth et al., 2013). However, the simulation model does not take the entire costs of redispatching into account.

The same conclusion has been reached by Jensen (2013) in a memo issued by Statnett stating their anticipated results from the implementation of FBMC in Norway. The memo emphasizes the importance of PTDF matrices replacing clear information about available capacity. FBMC will not impose significant changes to the Nordic financial power market (Jensen, 2013).

In EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2018), the results of market simulations of FB and NTC carried out by the Nordic TSOs are presented. The simulation results show that, on average, welfare gains are obtained when switching from NTC to FB, despite a welfare loss for some hours due to insecure NTC capacities. Remedial actions are applied similarly for both models in order to ensure comparability. The memo furthermore states how structural congestion, such as in the West Coast corridor, as well as export limitations in Norway, are dealt with in a more efficient way with FBMC. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018).

Nordic RSC (2019c) has conducted simulations on the price differences between NO3 and NO5 when adding an additional 100 MW transfer capacity between the two zones in the period between 2.12.2013 and 15.1.2014. The simulations showed that FBMC provided an equal or better market outcome, measured as increased Nordic economic welfare, in every simulated hour. Remedial actions, such as redispatching, have been applied through the FAV values. Furthermore, Nordic RSC (2019c) discusses the effect of loop flows on the market clearing solution. The concept of loop flows will be explained in chapter 4. The paper states that loop flows can be handled by counter trading or redispatching in the short run. In the medium term, however, they should be treated by reconfiguring bidding zones, and in the long run they should be handled by investments in the transmission grid.

Little academic work has been done regarding the effect of FBMC implementation specifically in the NO5 region. According to a seminar memo by Helseth (2013), FBMC will give smaller, but more frequent price differences than todays' method in the NO5 region. They found, according to their parallel simulations, that FBMC implementation will lead to a decrease in prices in NO5 and an increase in prices in the NO4 region due to an expected shift in production from NO5 to NO4. Moreover, an increase in DK1 and DK2 prices are expected due to more export during windy nights). Prices in Sweden are suspected to decrease, while prices in Finland will remain largely unchanged. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018).

It is not necessarily clear that the implementation of FBMC in the Nordic region will surpass the NTC model in all aspects and come without significant costs and risks. The criticism of the flow-based model previously discussed in this section is applicable also in a Nordic context. The success of the flow-based model in the Nordics will depend on factors such as the coordination between the TSOs (Bjørndal et al., 2018b), biding zone configuration and grid infrastructure (Voswinkel et al., 2019), and adequate monitoring and transparency of TSO behaviour (Marien et al., 2013).

In EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2014), Nordic TSOs explain how a more robust generic GSK strategy is a manner of managing uncertainty in net positions, hence reducing the uncertainty and limitations of flow-based market coupling.

Several master theses have also explored the subject of FBMC in a Nordic market context, mainly at the Norwegian University of Science and Technology (NTNU). Jegleim (2015) investigates GSK estimation strategies and their different quality and accuracy, a subject that is further elaborated by Svarstad (2016). Nordeng (2016) develops a new methodology for estimating net positions. Boury (2015) investigates the impact of the flow-based capacity parameters on the price and social welfare solutions. Bolkesjø and Rønneseth (2018) examines the effect of FMBC methodology on Nordic hydropower producers' surplus.

This thesis, however, will focus on how the implementation of flow-based market coupling in the Nord Pool region will affect the prices and power generators in the Nordics. The effect of new HVDC power cables will constitute different scenarios in the analysis. A particular emphasis on power generators in the NO5 region will be given.

4 Theory

This chapter will provide a theoretical explanation of congestion management in general, the Net Transfer Capacity method, and Flow-Based Market Coupling. The theoretical overview will be based on the fundamental principles of power markets and congestion management as outlined in chapter 2. After briefly explaining the NTC method in section 4.1, an overview over FBMC will be provided in section 4.2, explaining the general principles and the FBMC design parameters. Section 4.2.3 introduces nodal Power Transfer Distribution Factors (PTDF) and their importance for the FB methodology. Section 4.2.4 explains how nodal PTDFs can be aggregated to zonal PTDFs using Critical Network Elements (CNE) and Generation Shift Keys (GSK). Section 4.2.5 gives an explanation of Remaining Available Margins (RAM) and Flow Reliability Margin (FRM).

Although a nodal congestion management model is a realistic alternative in the Nordic region, it will not be elaborated on in this chapter or thesis. The reason for this choice is because the flow-based model is selected as the future model in the Nordic region (Statnett, 2019), and because the nodal model is besides the scope of the analysis in this thesis. The NTC methodology is not used in the simulation model, but included in the theoretical review as it is the current market coupling method in the Nordics.

4.1 The Net Transfer Capacity method

This section will provide a brief introduction to the Net Transfer Capacity (NTC) method, the currently used market clearing model. A more thorough explanation of the NTC model in the Nordic countries can be found in the technical report *Principles for determining the transfer capacity in the Nordic power market* by the European Network of Transmission System Operators (2008).

4.1.1 Principles of Net Transfer Capacity

The Net Transfer Capacity are the trading capacities between bidding areas and determined by each Transmission System Operator (TSO) and represent the maximum allowable commercial power exchange between two areas. These exchanges are based on historical data for a specific reference day, taking potential loop flows, seasonalities, and a justified security margin into account (KU Leuven, 2015). In The Nord Pool area, these NTC values are set on an hourly basis and for the next day. The Available Transfer Capacity (ATC) value may be derived from the corresponding NTC values by subtracting relevant long-term nominations between countries. Such nominations are reservations of transfer capacity between zones that are predetermined in the spot market. Although the ATC model is quite widespread in Europe, the Nordic countries uses an NTC model (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). Therefore, the NTC model will be explained in this section instead of the ATC model.

The NTC algorithm only considers commercial exchanges between two zones, leading to a significant simplification of the characteristics of the physical power grid (Van den Bergh et al., 2016). The values are calculated by TSOs based on their assumptions on the future market outcome, meaning that the capacity allocation happens ex-ante market clearing. Although the NTC model represents a rather simple market clearing algorithm, the calculated NTC values can be non-transparent for regulators. Due to the strong assumptions in the model, NTC values need to be underestimated to avoid physical line overloads. Hence, the transmission capacity made available to the market will in many cases be lower than the nominal grid capacity (Van den Bergh et al., 2016).

4.1.2 Calculating Net Transfer Capacity

Net Transfer Capacity allocation is defined as the difference between the Total Transfer Capacity (TTC) and the Transmission Reliability Margin (TRM) (European Network of Transmission System Operators, 2008), represented as the following equation:

$$NTC = TTC - TRM \tag{4.1}$$

Calculating the NTC values is a process in three steps. The first step is to calculate the TTC value between two areas. This is the maximum transmission when taking operational security standards applicable at each system into account, if future network conditions, generation and load patterns were to be predicted perfectly.

The next step is to calculate the TRM, a security margin that regards uncertainties related to deviations in physical flows, emergency exchanges between TSOs in case of unbalanced situations, and data inaccuracies. From these two calculations, the NTC value may be derived. Furthermore, the Nordic TSOs are committed to security standards, such as the N-1 criterion. The criterion entails that a power system can handle the loss of any single component, such as a production unit, line or a transformer (European Network of Transmission System Operators, 2008). The violation of this criterion can lead to thermal overloads, voltage collapse and power flow instability. In consequence, the only value limiting the maximum commercial trading volume between two areas in the day-ahead market is a pre-determined ATC value calculated as explained above (Bjørndal et al., 2018a).

In summary, the NTC and the FBMC algorithms both consist of an objective function set to maximize social-economic surplus, but are subject to different constraints. In both models, the net position for a zone, denoted as $\sum_z$, is calculated by supply and demand at a certain time in the market clearing. Although the constraints are different, the objective functions are identical; maximizing the social-economic surplus. The market optimization problem in the NTC and flow-based model can be formulated as in table 4.1.

	NTC formulation	Flow-based formulation
Objective function:	Maximize socioeconomic surplus	Maximize socioeconomic surplus
Subject to:	$\sum_z NP = 0$	$\sum_z NP = 0$
	NTC constraints	Flow-based constraints

Table 4.1: Market optimization problem in NTC and FBMC.

Where

z = A zone in the power market.

As explained above, the NTC constraints are derived from the TTC and TRM parameters. The characteristics of the flow-based constraints will be further explained in the following section.

4.2 Flow-based market coupling

4.2.1 General principles of Flow-based market coupling

This section will explain the general principles of Flow-Based Market Coupling. As discussed in section 4.1, the NTC model aggregates all expected network limitations with one single value that is determined ex-ante market clearing (Schavemaker et al., 2008). In the FB methodology, however, the physical laws of the network are partly incorporated in the market coupling algorithm model. Taking the available transmission capacity into account in a correct manner can be a challenging task, since the electricity spreads out across several parallel paths in the network, so-called loop flows, according to Kirchhoff's circuit laws. Furthermore, the flows are restricted by thermal limits.

Figure 4.1 illustrates how the power flow from SE1 in Northern Sweden can flow to NO2 in the south of Norway. The power also flows on parallel paths connecting the two zones, loop flows, and not necessarily only the physically shortest path. This concept is explained on page 34 in *The Economics of Electricity Markets* (Biggar and Hesamzadeh, 2014). Kirchhoff's circuit laws will not be further discussed in this chapter, but the curious reader might see chapter six in Biggar and Hesamzadeh (2014) for further explanations.

Figure 4.1: Illustration of loop flows from SE1 to NO2 (created by the authors).

The flow-based mechanism couples different electricity markets in a manner that increases the economic efficiency by matching the physical reality of the transmissions while simultaneously keeping operational security high (Van den Bergh et al., 2016), (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

Due to the abovementioned characteristics of electrical circuits, the allocated commercial trades between two zones cannot equal the entire transmission capacity of the grid. Some capacity will be needed for parallel flows resulting from electricity trade between other zones (Van den Bergh et al., 2016). Figure 4.2 illustrates this flow. Although power is transferred from a node in zone A to zone B, some electricity will possibly flow through zone C. As discussed above, FBMC takes these physical laws into account by implementing it as a part of the optimization problem. This model, however, needs to be simplified since it is implemented on a zonal rather than a nodal basis. This simplification will be explained further in section 4.2.4.

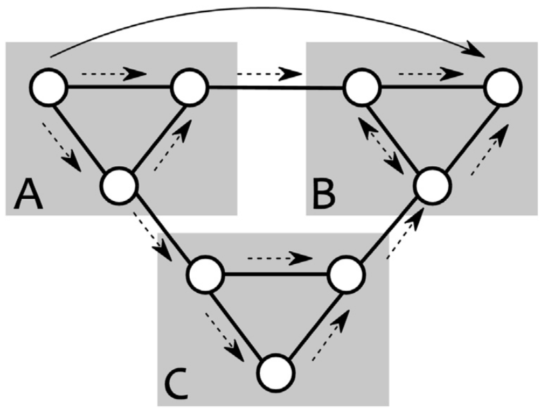

Figure 4.2: A commercial transaction between a node in market zone A and a node in market zone B resulting in a flow in the entire grid. Van den Bergh et al. (2016).

The simplified flow-based grid model allows the market to prioritize flows when identifying the most economically efficient solutions. Prioritization is done by analyzing how the trades from different bidding areas will affect the identified critical elements in the grid, where each boundary of the FBMC flow domain represents the limit of a critical line (Van den Bergh et al., 2016). In other words, the maximum allowable commercial electricity trade amount between two zones is dependent on the import and export between other zones.

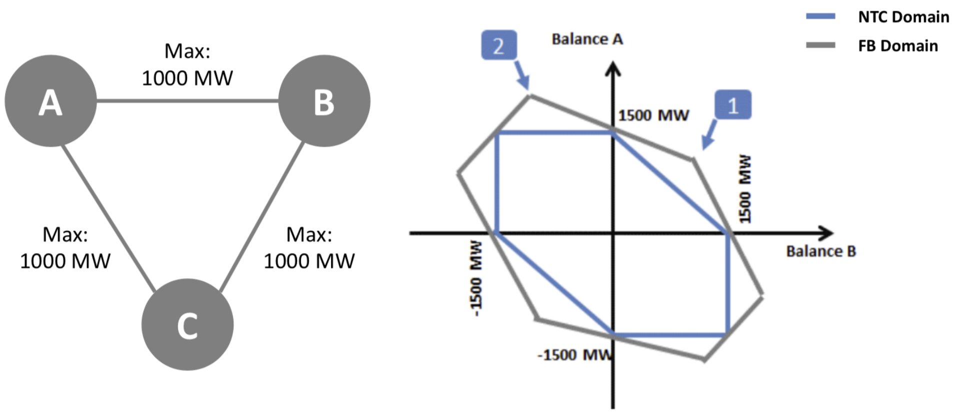

Figure 4.3: Three-node example on grid topology and corresponding FB and NTC solution domains (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018).

Figure 4.3 illustrates the solution domain, and hence the transmission capacity, of an arbitrary flow-based model (in grey) and NTC model (in blue). On the left, the grid topology is represented in a three-nodal example. It is assumed that node C is a consumption node and node A and B are generation nodes. The transfer capacity of each line, the three CNEs, is assumed to be 1000 MW and the lines' resistance are equal and set to 1 Ω. In the example in figure 4.3, the NTC domain is a part of the FB domain, where all NTC constraints are more or equally binding than the FB constraints in the maximization problem. It is important to note that this is not necessarily always the case, and it is possible that the ATC or NTC constraints provide a more optimal solution than the flow-based model for the same case. This is explained in Bjørndal et al. (2018a). The characteristics of the domain will be largely determined by the different FBMC design parameters. The upcoming sections will elaborate on the design parameters in the flow-based market coupling algorithm.

4.2.2 Market coupling

As touched upon in the previous section, capacity allocation in FBMC happens both ex-ante and simultaneously with the market clearing. This coupling can be divided into three phases, as described by EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2014); pre-market coupling, market coupling and post-market coupling. The flow-based market coupling process has similar elements to the day-ahead Elspot market procedure as outlined by Nord Pool Spot (2014) in section 2.1.4.

In the preliminary phase of pre-market coupling, the TSOs execute the capacity calculations in order to identify the solution domain. This consists of the following steps. First, the TSOs create a "base case" reflecting the expected grid topology for the next day, together with expected net positions of all bidding zones and corresponding flows on all Critical Network Elements (CNEs). Second, the Generation Shift Keys (GSKs), CNEs, Critical Branch Critical Outages (CBCOs), and other relevant parameters are calculated in order to create Power Transfer Distribution Factors (PTDFs) and the Remaining Available Margin (RAM) capacities. These parameters make up the solution domain as shown in figure 4.3 and will be explained in the upcoming sections of this chapter.

In the Nord Pool region, pre-market coupling starts the evening on D-2, two days before the power delivery, and lasts until 10:00 on D-1 when the parameters are published on the power exchange web site (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). On day D-1, the PX performs the day-ahead market coupling. This process involves the following steps: (1) Publishing the FB parameters to the market, (2) collecting bids from the market players, (3) calculating the market equilibrium, and (4) publishing the market result. This process starts at 10:30 at day D-1 and ends at 13:00 when the PX publishes the market results. In the case of congestion, re-dispatchment actions will be made in order to prevent congestion and operational security of the grid. The last phase, post-market coupling, is carried out by the TSOs and includes the verification of market results and an analysis of operational security. Furthermore, congestion information is shared with the market. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

The upcoming sections will elaborate on the calculation of RAM, PTDFs and other design parameters that are central to FMBC.

4.2.3 Nodal Power Transfer Distribution Factors

As discussed in the section above, the first parameters needed to calculate the FBMC domain are the Power Transfer Distribution Factors (PTDFs), which are computed at D-2 in the pre-market coupling phase. As explained in the section above, the flow-based model solves the market coupling problem by partly taking the physical characteristics of the grid into account. PTDFs represent the linear relationships of the lines in the grid and are tools used to understand how an incremental power injection in one area affects a particular line in the grid (Biggar and Hesamzadeh, 2014). In other words, a nodal PTDF explains how an incremental power transfer between two nodes affect the total power flow in the given system.

This thesis will not elaborate on the fundamental electricity concepts that the PTDF calculations are based on as is not crucial for the analysis in this thesis. However, the reader might see (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014) for a detailed description in a Nordic context.

In order to explain how nodal PTDFs are used in the FBMC model, a three-node example will be used. The example is based on the same assumptions as the example in figure 4.3. Assume further that the relevant TSO has calculated the PTDFs, which are represented in matrix form in table 4.2.

Line	RAM	A	B	C
A->B	1000	1/3	-1/3	0
A->C	1000	2/3	1/3	0
B->C	1000	1/3	2/3	0

Table 4.2: The PTDF matrix of the transmission grid in figure 4.3.

The PDTF matrix provides the linear relationships of the power grid as calculated by the TSOs. The "Line" in the first column represents the CNE in the grid and the "RAM" column is the remaining available margin for that given line. The last three columns represent the node where power is injected. For example, if the generation in node A were increased with 1 MW, one third of the generation (0,33 MW) would flow on the line between node A and B. Hence, the PTDF for node A on line A-B is 0,33. Notice also that the line between node B and C also would be affected by an increase in production in node A, as the PTDF for node A on line B-C also is 0,33. The flows of this particular example are illustrated in figure 4.4. The blue arrows represent the RAM for the given line. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018).

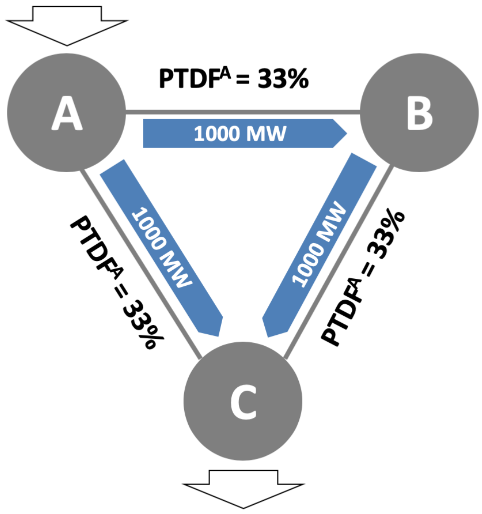

Figure 4.4: PTDFs in a three-node example.

Furthermore, TSOs use a so-called "slack node" as a reference point in the PTDF matrix to monitor flows on particular lines. In table 4.2, the slack node is Node C. A slack node is a mathematical construct executed by monitoring an injection in a particular node and the corresponding extraction in the selected slack node (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018). With the help of these slack nodes, the TSOs can use the PTDFs to represent the physical characteristics of the power grid in their D-2 capacity calculations.

The relationship between a power injection in a node and the power flow on a line in the same grid can be represented as in equation 4.2 (Jegleim, 2015).

$$P_{i,j} = PTDF_{i-j,m-n} * P_{m-n} \tag{4.2}$$

$PTDF_{i-j,m-n}$ represents the fraction of the power transaction from node m to node n that will in fact flow on the line between node i and node j. With the presence of a new power transaction in the grid, P_{m-n}, it will affect the power flow between node i and node j, P_i, j.

4.2.4 Aggregating nodal PTDFs to area PTDFs using Generation Shift Keys

So far in this chapter, PTDFs have only been discussed on a nodal level. However, the FBMC algorithm is applied to the grid on a zonal level, where several nodes are aggregated to zones in order to simplify the capacity calculations. This requires that the PTDFs are calculated to be applied on a power flow between zonas, and not between a node and a line (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). In other words, PTDFs from the base case are node-to-line PTDFs, but the FBMC methodology requires zone-to-CNE PTDFs. A zone-to-CNE PTDF matrix will in turn provide information on how a power transaction from one zone to another will influence the flow on the lines in the grid. As discussed in chapter 2, the Norwegian and Nordic power market is divided into several bidding zones, which supports the argument for a zonal approach.

In this case, these lines are the Critical Network Elements (CNEs), lines that may potentially make up a binding constraint in the FBMC optimization model. Power systems normally operate within the so-called N-1 criterion, as in the NTC model presented in section 4.1 (Van den Bergh et al., 2016). The criterion states that the power system has to be able to operate securely and stable after the loss of one single component, such as a line or transformer. In order to ensure operation within N-1, TSOs monitor certain grid elements. These monitored grid elements make up the critical network elements, and the critical state or contingency applied in the evaluation is called a critical outage (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

Hence, critical lines are considered in the N-state and in critical N-1 states. Each combination of a critical line under a critical state, referred to as Critical Branch Critical Outage (CBCO), is included in the transmission constraints (Van den Bergh et al., 2016). The CBCOs are referred to as CNEs in this thesis. In the Nordic synchronous area, CNEs are identified in two steps. First, Nordic TSOs test potential CNEs by simulating AC loads in different scenarios using the Common Grid Model (Nordic RSC, 2019c). This list of potential CNEs are thereafter used in the second step, where the TSOs identify which components in the power grid that will be stressed to their thermal limitation after the specified contingency (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). The pairs of stressed components and specific contingencies make up the CNEs for the given case tested. CNEs can be both within a bidding zone and on the border between different zones.

In order to convert node-to-line PTDFs from the base case to zone-to-CNE PTDFs, Generation Shift Keys (GSKs) are used to scale the power generation of a price area (Schavemaker et al., 2008). The GSKs are defined by the TSOs and describe how the net position of a zone is affected by the individual net positions of the corresponding nodes in that zone (Van den Bergh et al., 2016). In other words, GSKs provide the nodal contribution to a change in a zonal balance.

For example, a GSK with the value of 0,2 for node x in zone y would imply that the generation at node x would increase by 2 MW if the entire zonal balance of zone y increases by 10 MW. The PTDF for zone y is the weighted sum of all of the corresponding nodal PTDFs where the weights represent the GSKs. This is explained by the following equation (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2018).

$$PTDF_{i,j}^{Y} = \sum_{\alpha} GSK^{\alpha} PTDF_{i,j}^{\alpha} \ \ and \ \ \sum_{\alpha} GSK^{\alpha} = 1 \tag{4.3}$$

Where $PTDF_{i,j}^{Y}$ is the sensitivity of transmission element i, j to injection in bid zone Y;
$PTDF_{i,j}^{\alpha}$ is the sensitivity of transmission element i, j to injection in node α; and
GSK^{α} is the weight of node α on the PTDF of zone Y.

It is important to note that GSKs are a means to approximate the physical characteristics and are subject to several weaknesses. Firstly, accuracy is inevitably reduced in the process of aggregating several individual nodes into bidding zones as one loses the information on the exact nodal injections in the grid. It is a linear approximation of a non-linear relation, and hence, it is due to significant insecurity. Secondly, GSKs are determined ex-ante and based on predictions on the market outcome, leading to potential forecast errors.(Van den Bergh et al., 2016).

The generation shift keys can be calculated in different ways. A GSK strategy is a chosen method of linearizing the power flow in order to approximate the actual power flow as close as possible. There does not exist a universally correct GSK strategy, and different GSK strategies are used by different TSOs and can differ between geographical areas (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). This can for example be due to differences in generation technology and geographical distribution, as well as in time (Voswinkel et al., 2019). As discussed in chapter 3, using a wrong GSK strategy can have a large impact on the market solution (Marien et al., 2013). Hence, "a TSO should apply the GSK strategy that minimizes the prediction error between the forecasted and observed power flows for all generator units and loads in each bidding zone for a certain time span", according to the report *Methodology and concepts for the Nordic Flow Based Market Coupling* by EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2014).

Normally, units that include market-driven and flexible power plants, such as hydro power, gas-fired plants and coal-fired plants shall receive a non-zero GSK (Svarstad, 2016). When the plants are more sensitive to market changes, they receive a higher GSK factor in order to better linearize their power flows. The determination is based on historical data as well as TSO experience. GSKs for non-flexible production units are normally set to zero (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

Voswinkel et al. (2019) distinguish between two main types of GSKs; static and dynamic. Static GSKs are based on the characteristics of the power system that are subject to few changes over time. Dynamic GSK calculation, on the other hand, take certain variables into account, such as expected net exports. The simplest form of a GSK strategy is a flat one, meaning that the GSK of each node in a zone is set to 1/n, where n is the number of nodes in that particular zone (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). A flat strategy is more robust when the market solution deviates significantly from the predicted net position. A marginal strategy, however, simulates the flow more correctly when the net position is closer to the predicted net position. A significant limitation of a flat strategy is that could simulate more capacity to a node than its actual maximum installed capacity.

The Nordic TSOs must chose between one of the GSK strategies provided in appendix A2. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). A GSK strategy may be applicable for a bidding zone and applied for a defined time period. The selected GSK strategy must be communicated in a transparent manner to all market participants.

Furthermore, the TSOs must regularly evaluate and, if necessary, change the selected strategies. This must be done at least once a year and if significant changes occur in the grid. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

The selected GSK strategy in the Nordics and its implications on market clearing results will be further discussed in chapter 7. For a more detailed theoretical review of GSKs, the reader can study Marien et al. (2013) and Voswinkel et al. (2019). Svarstad (2016) and EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2014) explains GSKs in a Nordic context.

4.2.5 Remaining Available Margin

As previously described in this chapter, zonal PTDFs and Remaining Available Margin are the two FBMC parameters needed to calculate the market clearing. RAM is the line capacity that can be traded and used in the day-ahead market without compromising operational security, i.e. the "free margin" of a CNE (Van den Bergh et al., 2016). When the CNEs are identified as explained in section 4.2.4, the RAM for each line can be determined. This is calculated by the use of the following equation.

$$RAM = F_{max} - FRM - FAV - F'_{ref} \tag{4.4}$$

Where RAM = The Remaining Available Margin;
F_{max} = The maximum allowed flow on the CNE;
F'_{ref} = The reference flow at zero net positions when using the computed PTDF;
FRM = The Flow Reliability Margin; and
FAV = The Final Adjustment Value.

The F'_{ref} parameter is the reference flow of a given CNE in the event of a zero net position from the Nord Pool calculations, given the PTDF matrix calculated from the "base case". F'_{ref} is essentially a mathematical component that is necessary when linearizing the power flows from the common grid model, representing the the fixed component in the linear formulation of the power flow in the base case (Nordic RSC, 2019c).

In this section, the "base case" refers to the expected net positions of all bidding zones and corresponding flows on all CNEs for the day of the power delivery. The base case is calculated by the Nordic TSOs in the pre-market coupling phase (D-1) and based on the expected grid topology for the upcoming day (D). The rationale behind this base case calculation is that the power flows in a grid a given day are best forecasted by using the day before as a reference. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

In other words, the F'_{ref} parameter represents the pre-booked capacity for bilateral power trades internally in a given bidding zone. These flows are not included in the market coupling algorithm because they are both sent and received within the same bidding area, and thus are exposed to the same prices (Nordic RSC, 2019c). Hence, when the pre-booked capacity increases, F'_{ref} increases, and the remaining available margin is reduced. This reference flow is calculated as:

$$F'_{ref} = F_{ref} - PTDF * NP^{BC} \tag{4.5}$$

Where F_{ref} = The load on the CNE in the base case (D-1), given the net positions reflected in that base case;
NP^{BC} = The net position of the bidding zone base case; and
$PTDF$ = The zonal Power Transfer Distribution Factor as described in section 4.2.4

The F_{ref} parameter represents the forecasted power flow on the CNEs as constructed from the base case. Hence, F'_{ref} is calculated by subtracting the linearized DC-load flows based on the common grid model analysis, from the reference flow. These expected flows are calculated by multiplying the zonal PTDF with the expected net position in that base case. In other words, the pre-booked zone-internal capacity is calculated by reducing the actual flow in the base case with the flows calculated in the market coupling algorithm in the base case. (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014). The internal flows can be handled by the FBMC algorithm when the bidding zones are smaller and more numerous (Nordic RSC, 2019c).

The F_{max} value is the maximum flow allowed on a critical branch and can be determined from proactive relays that limit the power flows or the thermal limit of the equipment (Schavemaker et al., 2008). The FRM represents a security hedge that a TSO must take due to uncertainty in the grid forecast and selecting the CNEs, uncertainties caused by exchanges outside the FBMC area, imperfect GSK calculations when creating linear representation of the grid, and other model simplifications and approximations (Marien et al., 2013). The margins are measured in MW and based on historical registrations of the differences between CNE power flows calculated D-2 and the actual registered flows.

For a more detailed description on how the flow reliability margin is calculated by Nordic TSOs, see EnergiNet, Statnett, Fingrid and Svenska Kraftnät (2014). Furthermore, the Final Adjustment Value allows for operational skills, experience and other factors that cannot formally be calculated in the FB system, to be implemented by increasing or decreasing the RAM on a CNE (Van den Bergh et al., 2016). In an official recommendation by the European Union Agency for the Cooperation of Energy Regulators (2019), several regulations regarding the implementation of the minimum margin available for cross-zonal trade is presented. According to the regulation, RAM must be minimum 70% of the $Fmax$, the maximum thermal limit of a CNE.

In other words, the RAM is the maximum allowable power flow on a critical branch, reduced by three factors; the reference flow, the safety margin (FRM), and potentially an knowledge-based factor (FAV). The relation between the flow, net position and RAM as explained above can be illustrated in figure 4.5.

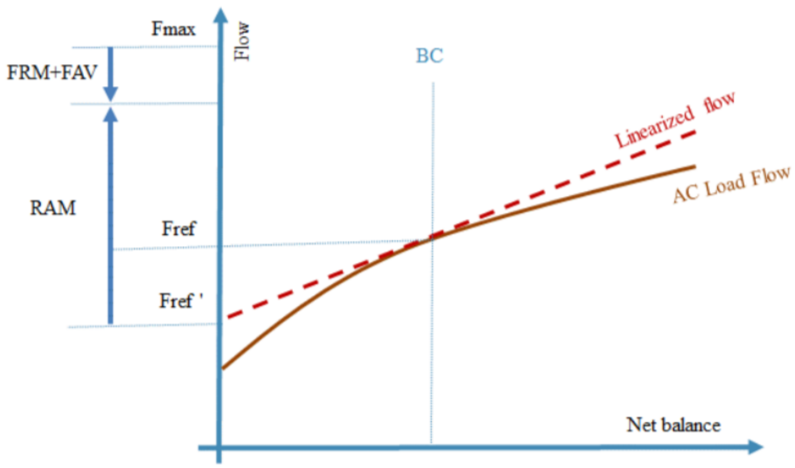

Figure 4.5: The relationship between Remaining Available Margin, net position and power flow (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2014).

The RAMs on each CNE, as well as the associated PTDFs and Net Positions (NP), make the foundation of the constraints in the general FB optimization problem:

$$PTDF * NP \leq RAM \tag{4.6}$$

Due to the fact that the FRM and FAV to a large extent can be set by the TSOs, the TSOs have a significant impact on the RAM calculations and hence the market clearing solution. For more information on how the remaining available margin is calculated, the reader can see Boury (2015).

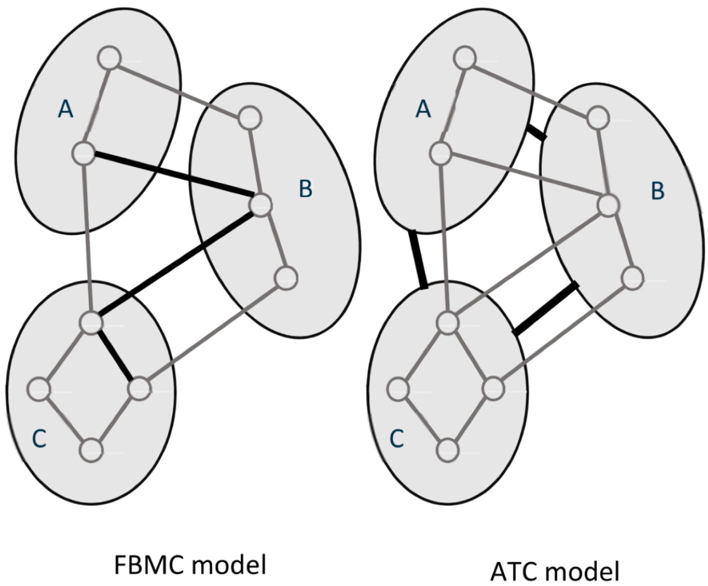

Figure 4.6: The differences between a nodal, flow-based and ATC model. Critical Branches illustrated in bold. Bjørndal et al. (2018a).

Figure 4.6 illustrates the key differences between the main market clearing models in the day-ahead market. In the FBMC model, the grid is divided into different price zones, and the restrictions derived from the laws of physics are applied only to the selected critical branches. In the ATC (or NTC) model, the grid is also aggregated to certain price zones, but the maximum transfer value between two zones are solely defined by an aggregate capacity, without any physical restrictions directly applied to lines within a price area. (Bjørndal et al., 2018a).

5 Methodology

The following chapter presents the methodology used for the analysis in this thesis. First, a discussion of the data and data sources used is presented, before moving on the chosen method. Finally, the solution approach and model implementation is discussed.

5.1 Choice of method

In order to analyze the differences between the market solutions of traditional capacity calculations and flow-based market coupling, several factors must be addressed. First of all, a simulation model of the power market has to be constructed to analyse the changes. Such a model can be built with severely different granularity, affecting data requirements and precision of results. Thereafter, capacity calculations will be imperative to analyse the price impact of the different calculation methodologies. Finally, constructions of the demand and supply for each area and their expected price sensitivity is needed to be able to accurately predict price differences.

When building a model of the power market, there are several options available both in scope and granularity. Firstly, a complete model with every access point, generator, consumer and transition point for the entire globe, would be the most accurate model possible. However, this is not feasible due to access to and precision of data, as well as the complications in intertwining different power systems. Natural geographical limitations also exist, such as by single countries, Europe as a whole, or grouping of countries by their market characteristics. This thesis limits geographically to the Nordics, including Norway, Sweden, Denmark and Finland.

There are several reasons for why limiting the market to these four Nordic countries is logical. This area is today regulated in similar ways and deeply intertwined with cross-border AC-connections. The countries' main regulators and TSOs have broad cooperation through initiatives such as the Nordic RSC (Nordic RSC, 2019a). Additionally, the model for the Nordic power market can be controlled quite well, as every connection from the Nordic market to the bordering countries are controllable DC-cables. Historical data and predictions will set the expectations for bordering demand and supply and allow the closed model to function quite accurately.

To address granularity of the market model, it is important to understand the implications on calculations and data requirements. The perfect model would include every node and access point, their connections and all the attributes of these. The necessity for large data amounts, computational power and understanding of physical implications with this kind of model would be extreme. Hence, it is not within the scope of this thesis. Instead, the chosen simplification method in this thesis is to analyze power data on a zonal level. As discussed in section 4.2.1, the Nord Pool Spot market is divided into several bidding zones. The model used in this thesis follows this approach by dividing the Nordic power market into the twelve price areas, allowing for an analysis on a zonal level.

Capacity calculations are core in the way the power models distribute power and decide prices for the different price areas. The traditional approach of NTC calculation is still being used in the Nordic power market (Nordic RSC, 2019c). However, the transition to FBMC is decided and will be implemented within a few years (Statnett, 2019).

The supply and demand for each zone could be approached in several ways. One way could be a bottom-up model of every power source and their expected price sensitivities. Similarly, one could produce a model of the expected demand from both private households and corporate consumption. The preferable approach, however, is to use the aggregated bid curves for each zone, as these will be the true supply and demand sensitivity for each zone.

5.2 Data and data sources

Collection of relevant data is challenging in the Nordic area, as the owners of relevant data (Statnett and Nord Pool) are quite restrictive in their approach to data sharing. As the Nordic power market will open for multiple PXs to be Nominated Electricity Market Operators (NEMOs), increased transparency of data is expected (Nord Pool Group, 2019e). Especially data on supply and demand bid curves will be more easily available as these will be integrated in a cross-platform approach.

The model for the Nordic power market would require significant details about physical lines and their attributes to be modeled perfectly. For the Nordic power market, these details are not available, as especially the Norwegian transmission network is vulnerable with some critical points, making the network details a matter of national security.

This thesis will build the market model on two main data sources; the Nordic RSC simulations in January - March 2017 retrieved from Nordic RSC (2019b), and Nord Pool data exports retrieved from Nord Pool Group (2019c) and Nord Pool Group (2019d). The Nordic RSC simulation results contain critical information on grid connections and capacity calculations. The 2017 data is the latest available simulations, as there has been limited publications on the area. All model data and characteristics are pulled from this data set, including line capacities, zonal PTDFs and all connection points. To model supply and demand, Nord Pool data on consolidated bid curves are used. These curves will be disaggregated to fit the twelve price areas of the Nordic power market. The chosen method of disaggregation is discussed in the following section.

5.3 Solution approach and implementation

5.3.1 Model construction

The model implementation is done in the optimization software GAMS, a software specialized in optimization of large scale problems such as the power market pricing models. The model of this thesis builds on the work of Bjørndal et al. (2018a) and Bjørndal et al. (2018b), where they addressed differences between NTC capacities and FBMC capacities. The model will be an NLP optimization problem, solved with the MINOS solver in GAMS.

Defining sets, variables and parameters:

Sets

i, j, ii	zones
l	bids from consumers
k	bids from producers

Parameters

$e_{i,k}$	constant term for supply bid curve
$c_{i,k}$	slope for spot market marginal cost curve
$gen\_ub_{i,k}$	generation upper bound
$a_{i,l}$	constant term for demand bid curve
$b_{i,l}$	slope for demand bid curve in spot market
$con\_ub_{i,l}$	consumption upper bound
$capmax_{i,j}$	line maximum FB capacities
$capmin_{i,j}$	line minimum FB capacities
$ntcmax_{i,j}$	line maximum ntc capacities
$ntcmin_{i,j}$	line minimum ntc capacities
$ptdf_{i,j,ii}$	zonal ptdf matrix

Positive variables

$qg_{i,k}$	Spot market generation quantity
$gc_{i,l}$	spot market consumption quantity

Variables

q_i	net injection quantity
$f_{i,j}$	line flow

5.3.1.1 NTC model

The following section describes how a NTC model could be built, to compare to the flow-based model. The NTC model can use NTC-capacities as defined by the Nordic RSC simulation results, and is the combined capacity of the available transmission lines between each zone. This model is therefore already consolidated on a zonal level, allowing for a simplification compared to the previously used models. The implications of this simplification is the need to trust Nordic RSCs implementation and combination methodology, however there is no reason to believe these methods are significantly different from the currently operating model on Nord Pool, which would be the comparable option.

The zonal NTC model is defined by the following objective function and set of constraints:

NTC capacity model

$$\max \sum_{i,l} (a_{i,l} * qc_{i,l} - 0.5 * b_{i,l} * qc_{i,l}^2) - \sum_{i,k} (e_{i,k} * qg_{i,k} + 0.5 * c_{i,k} * qg_{i,k}^2) \tag{5.1}$$

Subject to:

$$\sum_i q_i = 0 \tag{5.2}$$

$$0 < qg_{i,k} < gen\_ub_{i,k} \quad \forall i, k \tag{5.3}$$

$$0 < qc_{i,l} < con\_ub_{i,l} \quad \forall i, l \tag{5.4}$$

$$ntcmin_{i,j} < f_{i,j} < ntcmax_{i,j} \quad \forall i, j \tag{5.5}$$

$$q_i = \sum_k qg_{i,k} - \sum_l qc_{i,l} \quad \forall i \tag{5.6}$$

$$q_i - \sum_{j \neq i} f_{i,j} = 0 \quad \forall i \tag{5.7}$$

5.3.1.2 FBMC model

The flow-based model will be built in a similar manner to the NTC model, using the Nordic RSC simulations and their calculated zonal PTDFs. The method will therefore be very similar to the approach of Bjørndal et al. (2018a) and Bjørndal et al. (2018b). The use of zonal PTDFs does imply trusting the Nordic RSCs choice of GSK strategy and aggregation method. If the GSK strategy and approach changes, the zonal PTDFs could be significantly different, as previously discussed in this thesis. Through discussions with Statnett, it seems like the calculation of PTDFs will continue to be a task for the TSOs after the implementation in 2021, and therefore one would assume that the approach Nordic RSC is developing would be the gold standard for these calculations. As they are developing the flow-based model for the Nordic network, the strategies might change. Their latest approach is the one used in the 2017 simulations, however, this strategy might be different to the final implementation.

The zonal FBMC model is defined by the following goal function and set of constraints:

FBMC capacity model

$$\max \sum_{i,l}(a_{i,l} * qc_{i,l} - 0.5 * b_{i,l} * qc_{i,l}^2) - \sum_{i,k}(e_{i,k} * qg_{i,k} + 0.5 * c_{i,k} * qg_{i,k}^2) \tag{5.8}$$

Subject to:

$$\sum_i q_i = 0 \tag{5.9}$$

$$0 < qg_{i,k} < gen\_ub_{i,k} \quad \forall i,k \tag{5.10}$$

$$0 < qc_{i,l} < con\_ub_{i,l} \quad \forall i,l \tag{5.11}$$

$$capmin_{i,j} < f_{i,j} < capmax_{i,j} \quad \forall i,j \tag{5.12}$$

$$q_i = \sum_k qg_{i,k} - \sum_l qc_{i,l} \quad \forall i \tag{5.13}$$

$$f_{i,j} = \sum_{ii} q_{ii} * ptdf_{i,j,ii} \quad \forall i,j \tag{5.14}$$

5.3.2 Network and input data

The following section will describe the approach chosen to model the network and which input data are used and how they are processed when inputted to the model.

5.3.2.1 Nordic network and HVDC connections

The Nordic network model used in this paper is built on the 12 price areas, with each price area represented as a node. Furthermore, each of the connections between zones are modeled as lines between the nodes. For all AC connections, this implementation is simple and are modeled as direct lines between the nodes with capacities as done by the different capacity calculation methodologies. For the NTC model, the HVDC lines connecting zones can be modeled in the same way as AC connections, as they are directly input into the market coupling algorithm. As the scope of this thesis is to look at individual hours, ramping of HVDC connections is not relevant.

The flow-based model integrates HVDC connections slightly different, as the HVDC connections are controllable and can not be included in the flow-based calculations directly. The approach by Nordic RSC in their simulations is to use Advanced Hybrid Coupling (AHC), generating virtual bidding zones for all HVDC connections, combining NTC capacities with the flow-based model (Nordic RSC, 2019c). This implementation implies that the constructed zonal PTDFs include the expected flows on HVDC cables and are therefore defined for the specific operating hour. The published PTDFs are on a zonal level, while the nodal PTDFs are anonymised and not feasible to use in a model. The implementation of HVDC cables and AHC would therefore be extremely challenging to do in a meaningful way. This would require information that currently is defined as highly confidential by the TSOs, and guesswork would increase uncertainty significantly. The chosen implementation is to build HVDC flows directly into the connected bidding zones as shifts in bid curves. For the HVDC-cables within the Nordic area, implications are that the flow will be pre-defined in the flow based models. These predefined values are taken from the calculated flows on the lines from the Nordic RSC simulations.

The model including HVDC connections can be visualized in the following way:

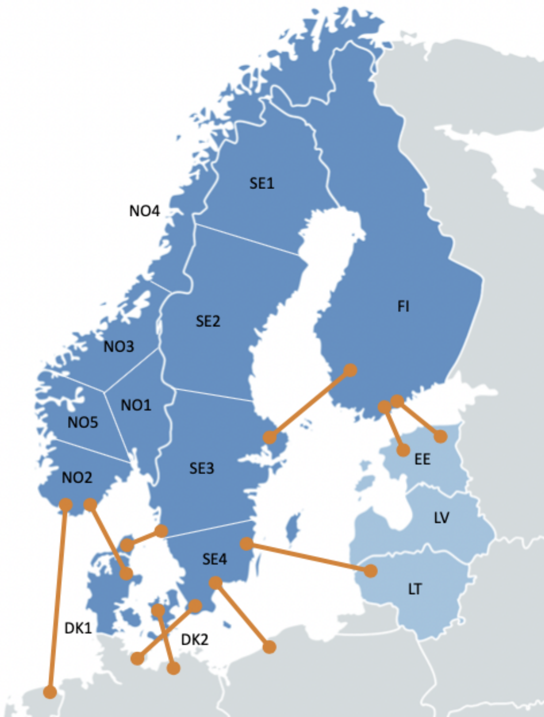

Figure 5.1: Current HVDC-connections in the Nordics (European Network of Transmission System Operators, 2019).

5.3.2.2 Disaggregation of bid curves

Supply and demand curves are not available in a format that would be directly usable as input data to the model, as Nord Pool does not publish the individual zonal bid curves. The available data is the total network supply and demand curves for each operating hour of the year. The approach used in this thesis is to use these aggregated bid curves and disaggregate them to a zonal level, using the software "R". There are several ways to disaggregate the bid curves, however the initial approach chosen is a simple pro-rata distribution to the different zones based on their clearing quantities. The implications of this implementation is that every zone will have the same relative price sensitivity.

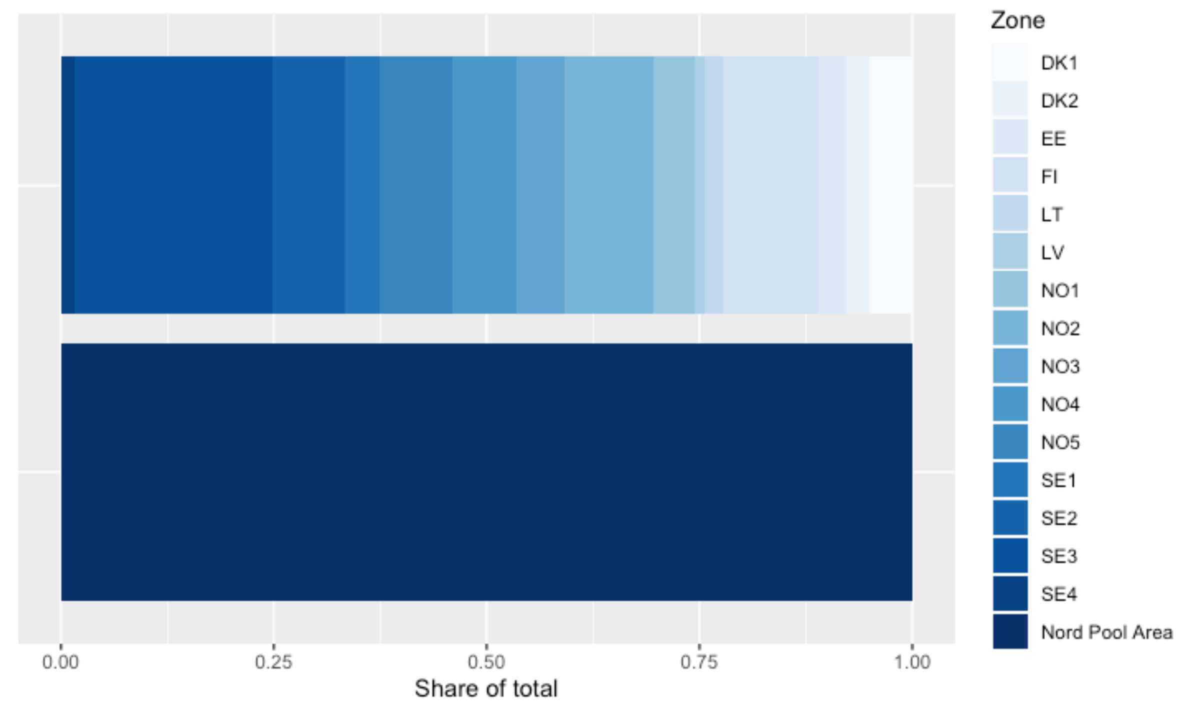

Figure 5.2: Price areas share of total production in Nord Pool Area.

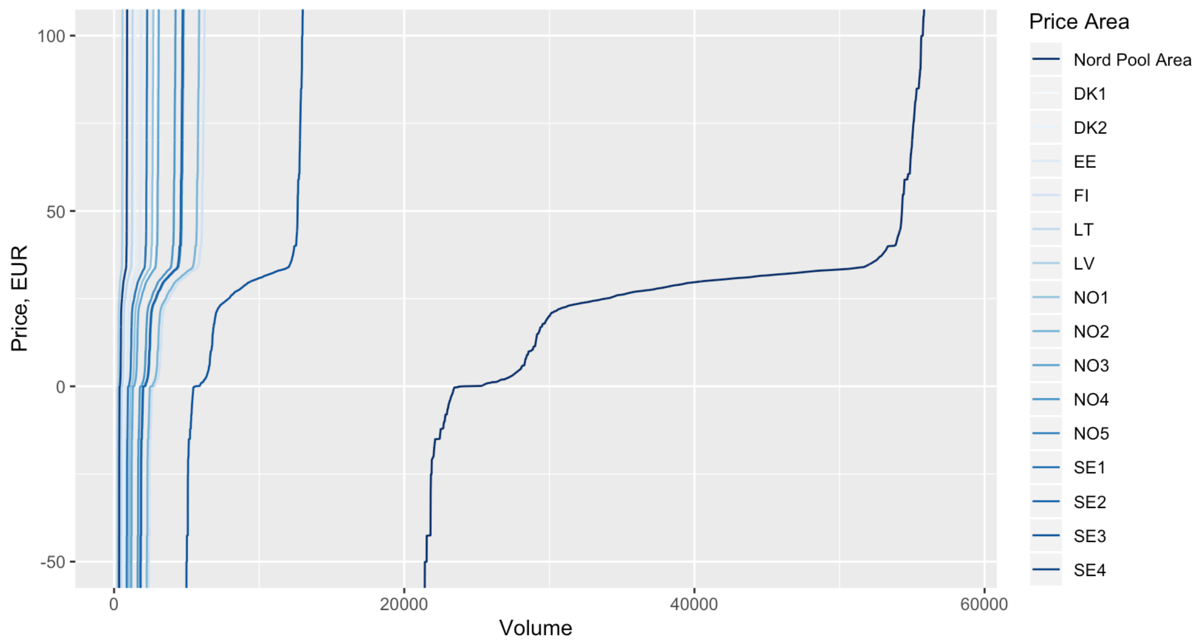

Figure 5.3: Sell curve from Nord Pool disaggregated to a zonal level. Example, partition of full curve.

The bid curves from Nord Pool are split into several hundred points of data, where each point represents a price and the corresponding supply and demand quantities. To better accommodate the optimization algorithm, one would want linear bid curves for demand

and supply, as a clearing point could be in between any two of the specific points in the bid curve.

To further improve computational time, the number of points are reduced with approximately 70%, removing the points with the shortest distances between each other. The linearisation of the curves will ensure that impact on data quality is minimal, as most points would have very little deviation from the linearized curve.

5.3.2.3 Capacity calculations

The capacities of every single line is important input data for the power market model. These capacities are calculated in several different ways and are mostly in the hands of the individual TSOs. The model in this thesis is based on capacity calculations from the Nordic RSC flow-based market coupling simulations of 2017. This includes FBMC-capacities as well as NTC capacities for the same time frames. The line capacities are inputted in the two different models as capacity constraints on the zonal connections.

5.4 Choice of operating hours

In this section, the choice of operating hours for further analysis will be explained. As mentioned in section 5.2, the Nordic RSC has published FBMC day-ahead simulation data from January to March 2017, with prices and quantities on an hourly basis. Hence, the choice of hours must be within this time span. The chosen operating hours are 1) between 04.00 and 05.00 and 2) between 08.00 and 09.00 CET on Friday the 3rd of February 2017. Two single hour slots have been chosen in order to conduct similar analysis and scenarios on two different market solutions. The two hours are on the same day in order to minimize external factors that reduces the comparability of the scenarios, such as grid maintenance.

The two hours are selected as they represent two different levels of congestion in the grid. Between 04 and 05, the prices are similar in all zones, 30,26 EUR/MWh, except for one zone. The prices are also fairly close to the system price of 30,21 EUR/MWh (Nord Pool Group, 2019c). Between 08 and 09, however, there were relatively high price differences accross the entire Nordic region. During this hour, the day-ahead price was 25,95 EUR/MWh in NO4, while it was 48,31 EUR/KWh in SE4, FI, DK2 areas. Thus, the highest price was 86,17% higher than the lowest price, which is relatively substantial.

The system price was 34,55 EUR/KWh. The prices in the selected operating hours can be seen in tables 5.1 and 5.2. The turnover at system price in the selected hour was 58.048,2 MWh for the entire Nord Pool area (Nord Pool Group, 2019d).

Hour	System	SE1	SE 2	SE3	SE4	FI	DK1	DK2
04-05	30,21	30,26	30,26	30,26	30,26	30,26	30,26	30,26
08-09	34,55	37,15	37,15	37,15	48,31	48,31	33,42	48,31

Table 5.1: Selected hourly day-ahead prices on 03.02.2017. Prices in EUR/MWh. (1/2)

Hour	System	NO1	NO2	NO3	NO4	NO5
04-05	30,21	30,26	30,26	30,26	30,26	24,58
08-09	34,55	33,42	33,42	37,15	25,95	31,91

Table 5.2: Selected hourly day-ahead prices on 03.02.2017. Prices in EUR/MWh. (2/2)

The Norwegian Energy Regulation Authority (NVE) publishes a weekly report on the power situation in the Nordics. According to the report from week five in 2017, the Nordic power prices were relatively high during this period (Norwegian Energy Regulatory Authority, 2019b). The increase in prices were driven by dry weather and less wind in the region. Although wind production increased in Denmark, the Swedish wind production was reduced by 50%, 200 GWh, compared to the preceding week. The total Norwegian precipitation-generated power in week 5 was 0,8 TWh, wich is only 25% of the normal levels.

6 Analysis

This section will present the simulation results from the different scenarios of the flow-based market clearing solution in the Nordic power market. The emphasis of this analysis is particularly to analyze the impact new HVDC cross-border interconnectors on day-ahead prices in the Nordic region in general, and NO5 in particular.

First, the results from the general base case simulation will be presented and compared to the Nordic RSC market simulation results. Secondly, the impact of the NordLink, NorthSeaLink and NorthConnect interconnectors will be shown as scenario 1, 2 and 3, respectively. The analysis is conducted on a cumulative basis as the three cables will be built in a specific order (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). As discussed in section 2.3, NorthConnect is yet only in a planning phase and not under construction. The simulated flow-based prices are simulated for all three scenarios during two different different operating hours with different levels of congestion. Lastly, a descriptive analysis on the distribution of constrained and non-constrained hours will be presented.

6.1 Base case scenario and Nordic RSC flow-based solution

The base case scenario is constructed as a simplification of the actual Nordic power grid as it is today. As explained in chapter 5, the model divides the Nordic grid into zones according to the Nord Pool bidding zone configuration shown in figure 2.3, excluding the bidding zones in the Baltic region. By using bid data from Nord Pool and simulation data provided by the Nordic RSC, the model simulates the flow-based market clearing solution in the Nordic regions.

The Nordic RSC has over a longer period conducted a flow-based market simulation which acts as a baseline in this thesis. The simulation results from the Nordic RSC analyses are presented in the second column of the simulation results tables, under the headline "Nordic RSC" in table 6.1.

The third column in table 6.1 shows the day-ahead flow-based prices as simulated using the GAMS-model explained in chapter 5. The prices are shown in EUR/MWh for hour 0800-0900 (CET) on the 3rd of February 2019, which represents the base case for the more constrained hour. One can, as discussed in section 5.4, immediately see that the price variance between different zones are relatively large. The differences occur as a result of congestion between the different zones, as explained in section 4.2.1. The simulation results from the base case approximates the flow-based market clearing prices in the Nordic RSC solution.

Zones	Nordic RSC	Base case
DK1	33,42	33,38
DK2	48,18	48,35
FIN	48,18	48,23
NO1	33,42	33,52
NO2	33,42	33,43
NO3	37,14	34,93
NO4	25,95	26,86
NO5	31,92	33,69
SE1	37,14	37,04
SE2	37,14	37,08
SE3	37,14	37,27
SE4	48,18	48,33

Table 6.1: FB day-ahead prices in base case, constrained hour (08-09). Prices in EUR/MWh.

A side by side comparison of all scenarioes presented and analyzed in this thesis is available in Appendix A4.

Table 6.2 below shows the Nordic RSC and simulated base case day-ahead prices for the hour 0400-0500 on the 3rd of February 2019. This operating hour represents a period with smaller price differences between zones, and hence, less congestion in the Nordic power grid.

Zones	Nordic RSC	Base case
DK1	30,1	31
DK2	30,11	31,07
FIN	30,13	32,29
NO1	30,1	30,96
NO2	30,1	30,98
NO3	30,05	30,75
NO4	24,55	23,91
NO5	30,1	30,94
SE1	30,13	31,25
SE2	30,12	31,1
SE3	30,11	31,1
SE4	30,11	31,07

Table 6.2: FB day-ahead prices in base case, constrained hour (04-05). Prices in EUR/MWh.

There are several reasons for why the simulation results in the base case analyses differ from the Nordic RSC prices. Firstly, the Nordic RSC has access to more complete data on the bid curves of the market participants. The model in this thesis has used aggregated bid curves based on public available data and disaggregated them to a zonal level. Secondly, the model used in this thesis only simulates the 12 Nordic bid zones, which simplifies the actual characteristics of the interconnected Elspot market area. Thirdly the Nordic RSC has applied a so-called Hybrid Market Coupling (HMC) model that accurately calculates the power flow on HVDC cables using flow-based market coupling and a NTC zone. The interconnection between two zones with different market clearing models has been simplified in the model used in this thesis. Despite the above mentioned simplifications, the results do provide valuable insights on how Nordic power prices will be affected by new cross-border interconnectors in a flow-based market coupling model.

6.2 Implementing NordLink in the FB-model

6.2.1 Implementation

In this section, the effect of implementing the NordLink cable has been simulated on the flow-based market clearing solution. This will be called scenario 1. The NordLink subsea HVDC cable will have a total capacity of 1400 MW and is expected to be completed in the year of 2020. The cross-border interconnectors will stretch between the NO2 price zone in the south of Norway to Northern Germany. We assume that the full transfer capacity will be utilized in both the constrained and the less constrained hours due to the price differences between the NO2 and the day-ahead price in the German market in this very scenario. The day-ahead power price in the German NordLink connection point is 60,27 EUR/MWh in the hour between 08-09 and 32,59 EUR/MWh between 04-05, as illustrated in table 6.3.

Hour	Price
04-05	32,59
08-09	60,27

Table 6.3: Actual prices at German NordLink connection point. Prices in EUR/MWh.

6.2.2 Simulation results

The simulation results shown in table 6.4 illustrate the flow-based market clearing prices in the Nordic region when we include the presence of the NordLink interconnector. The results show the day-ahead prices for hour 08-09. Overall, prices increase in the entire Nordic region. Only in DK2 can we observe a reduction in the price against the base case, although it is a humble reduction of 2 cents per EUR/MWh, while DK1 experiences zero change.

In all other zones, scenario 1 leads to an increase in prices. NO2, the zone in which the interconnector is linked to the Nordic market, experiences the highest price increase in both relative and absolute terms. In this zone, the price increases by 11,79 EUR/MWh to 45,22 EUR/MWh, or by 35,26%. The simulated price in the NO5 bidding zone is 45,13 EUR/MWh. On average, the prices increase by 15,55%.

Zones	Nordic RSC	Base case	NordLink
DK1	33,42	33,38	33,38
DK2	48,18	48,35	48,33
FIN	48,18	48,23	48,6
NO1	33,42	33,52	45,19
NO2	33,42	33,43	45,22
NO3	37,14	34,93	44,61
NO4	25,95	26,86	26,9
NO5	31,92	33,69	45,13
SE1	37,14	37,04	45,62
SE2	37,14	37,08	45,56
SE3	37,14	37,27	45,54
SE4	48,18	48,33	48,35

Table 6.4: FB day-ahead prices in scenario 1, constrained hour (08-09). Prices in EUR/MWh.

Table 6.5 illustrates the results of scenario 1 in the operating hour four hours earlier, between 04-05 the same day. One can immediately observe that the differences in day-ahead prices are smaller and more even than in the operating hour with more grid congestion. DK1 experiences zero difference in prices, while prices increase by 0,7 and 0,47 EUR/MWh in FIN and NO4, respectively. In the other simulated zones, including NO5, the increase in prices is between 0,66 and 0,67 EUR/MWh, or just over 2%.

Zones	Nordic RSC	Base case	NordLink
DK1	30,1	31	31
DK2	30,11	31,07	31,74
FIN	30,13	32,29	32,99
NO1	30,1	30,96	31,63
NO2	30,1	30,98	31,64
NO3	30,05	30,75	31,41
NO4	24,55	23,91	24,37
NO5	30,1	30,94	31,6
SE1	30,13	31,25	31,92
SE2	30,12	31,1	31,77
SE3	30,11	31,1	31,76
SE4	30,11	31,07	31,74

Table 6.5: FB day-ahead prices in scenario 1, unconstrained hour (04-05). Prices in EUR/MWh.

6.3 Implementing NSL in the FB-model

6.3.1 Implementation

For this second case, scenario 2 from now on, the connection of cross-border interconnector NorthSeaLink (NSL) will be simulated. As briefly presented in section 2.3, NSL is planned to be completed in 2021 and will connect the NO2 bidding zone with the power market in the UK (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). The subsea HVDC interconnector will have a total transfer capacity of 1400 MW, similar to the above mentioned NordLink interconnector.

Notice that the simulation of day-ahead prices include both the simulated NordLink and the NSL interconnectors, as NordLink is highly likely to be completed before the NSL cable (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). As for the NordLink scenario, full capacity utilization of the interconnectors is assumed in the less constrained hour. In the more constrained hour, price convergence is met before there is full load on the cable. Therefore load on this cable is only increased to the point where convergence happens. The rationale behind this decision is, also in this scenario, that the day-ahead prices in the NSL connection zone in the UK are higher than in the Nordic region. The UK simulation prices are illustrated in table 6.6.

Hour	Price
04-05	40,93
08-09	62,13

Table 6.6: Actual prices at UK NSL connection point. Prices in EUR/MWh.

6.3.2 Simulation results

The simulation results from scenario 2 are illustrated in 6.7 for operating hours 08-09. Several changes from the previous scenario can immediately be identified. All bidding zones, except for DK1, experience an increase in day-ahead prices compared to both the base case and with the sole presence of NordLink. The greatest absolute and relative price increase compared to the previous scenario can be found in FIN, with 15,14 EUR/MWh, or 31,2%.

NO2 has the gratest increase in price compared to the base case, with a new simulated price of 58,02 EUR/MWh. The NSL cable leads to a new simulated price in NO5 of 57,86 EUR/MWh, 24,17 EUR/MWh higher than in the NordLink scenario. The new average day-ahead price is 53,97 EUR/MWh, which is 23,97% higher than in the NordLink scenario and 43,26% higher compared to the base case. Hence, we observe that the Nordic prices converge towards the prices in the UK, and that the effect can be seen in the entire Nordic market.

Zones	Nordic RSC	Base case	NordLink	NSL
DK1	33,42	33,38	33,38	33,38
DK2	48,18	48,35	48,33	58,43
FIN	48,18	48,23	48,6	63,74
NO1	33,42	33,52	45,19	57,96
NO2	33,42	33,43	45,22	58,02
NO3	37,14	34,93	44,61	56,98
NO4	25,95	26,86	26,9	27,04
NO5	31,92	33,69	45,13	57,86
SE1	37,14	37,04	45,62	58,68
SE2	37,14	37,08	45,56	58,58
SE3	37,14	37,27	45,54	58,55
SE4	48,18	48,33	48,35	58,46

Table 6.7: FB day-ahead prices in scenario 2, constrained hour (08-09). Prices in EUR/MWh.

Table 6.8 illustrates the simulation results from scenario 2 in the operating hour between 04 and 05 the same day. As in scenario 1, the price changes observed are relatively small and evenly distributed. The simulated price increases in all of the bidding zones, except for in DK1. For all of the remaining zones, the price increases by between 0,54 and 0,56 EUR/MWh. The new simulated average price is 31,64 EUR/MWh, which is 1,64% higher than in scenario 1, and 3,65% higher than in the base case scenario.

The new day-ahead price in NO5 is 32,16 EUR/MWh, 1,77% or 0,56 EUR/MWh higher than in scenario 1 and 3,94% or 1,22 EUR/MWh higher than in the base case. Hence, in the operating hour between 04 and 05, the increase in prices is relatively similar between scenario 2 and scenario 1, as it is between scenario 1 and the base case.

Zones	Nordic RSC	Base case	NordLink	NSL
DK1	30,1	31	31	31
DK2	30,11	31,07	31,74	32,3
FIN	30,13	32,29	32,99	33,55
NO1	30,1	30,96	31,63	32,19
NO2	30,1	30,98	31,64	32,2
NO3	30,05	30,75	31,41	31,97
NO4	24,55	23,91	24,37	24,91
NO5	30,1	30,94	31,6	32,16
SE1	30,13	31,25	31,92	32,48
SE2	30,12	31,1	31,77	32,33
SE3	30,11	31,1	31,76	32,32
SE4	30,11	31,07	31,74	32,3

Table 6.8: FB day-ahead prices in scenario 2, unconstrained hour (04-05). Prices in EUR/MWh.

6.4 Implementing NorthConnect in the FB-model

6.4.1 Implementation

For the last simulated scenario, scenario 3, the implications of NorthConnect on Nordic day-ahead power prices will be presented. NorthConnect is a planned subsea HVDC connector that, if built, will connect NO5 in Norway with Scotland in the UK. The interconnector will, similar to NordLink and North Sea Link, have a total transfer capacity of 1400 MW (EnergiNet, Statnett, Fingrid and Svenska Kraftnät, 2019). Again, full cable transfer capacity is assumed for the less constrained hour, due to the price difference between the Nordic bidding zones and the UK, as presented in table 6.6. In the constrained hour, no flow is added, as will be further discussed in the following section.

6.4.2 Simulation results

The simulation results from scenario 3 in the 08-09 case is presented in 6.9. The results show that none of of the Nordic bidding zones have experienced any price difference compared to scenario 2. The average zonal price is still 53,97 EUR/MWh. Hence, the price has fully converged through the presence of the NSL cable, resulting in no further price increases in the flow-based simulation. Due to the price convergence, there will be no difference on prices of whether power is transported on the NSL or the NorthConnect interconnector.

Zones	Nordic RSC	Base case	NordLink	NSL	NorthConnect
DK1	33,42	33,38	33,38	33,38	33,38
DK2	48,18	48,35	48,33	58,43	58,43
FIN	48,18	48,23	48,6	63,74	63,74
NO1	33,42	33,52	45,19	57,96	57,96
NO2	33,42	33,43	45,22	58,02	58,02
NO3	37,14	34,93	44,61	56,98	56,98
NO4	25,95	26,86	26,9	27,04	27,04
NO5	31,92	33,69	45,13	57,86	57,86
SE1	37,14	37,04	45,62	58,68	58,68
SE2	37,14	37,08	45,56	58,58	58,58
SE3	37,14	37,27	45,54	58,55	58,55
SE4	48,18	48,33	48,35	58,46	58,46

Table 6.9: FB day-ahead prices in scenario 3, constrained hour (08-09). Prices in EUR/MWh.

In table 6.10, the simulation results from scenario 3 are presented for the operating hour between 04 and 05. As opposed to in the later operating hour for the same scenario, there exists some additional price convergance under the presence of the simulated NorthConnect cable. The average day-ahead price increases from 31,64 EUR/MWh in scenario 2, to 32,26 EUR/MWh. This is a 1,94% from scenario 2 and a 5,63% increase from the base case. Except for DK1, which has experienced no change in prices at any simulations, all of the bidding zones have seen an increase in prices of between 1,69 and 2,21% compared to scenario 2, and between 5,94 and 6,19% increase from the base case.

Zones	Nordic RSC	Base case	NordLink	NSL	NorthConnect
DK1	30,1	31	31	31	31
DK2	30,11	31,07	31,74	32,3	32,98
FIN	30,13	32,29	32,99	33,55	34,29
NO1	30,1	30,96	31,63	32,19	32,87
NO2	30,1	30,98	31,64	32,2	32,89
NO3	30,05	30,75	31,41	31,97	32,65
NO4	24,55	23,91	24,37	24,91	25,33
NO5	30,1	30,94	31,6	32,16	32,85
SE1	30,13	31,25	31,92	32,48	33,18
SE2	30,12	31,1	31,77	32,33	33,02
SE3	30,11	31,1	31,76	32,32	33,01
SE4	30,11	31,07	31,74	32,3	32,99

Table 6.10: FB day-ahead prices in scenario 3, unconstrained hour (04-05). Prices in EUR/MWh.

6.5 Distribution of constrained hours and price differences

The previous sections show that changes in FBMC-calculated prices highly depends on a few factors, especially price difference between zones and whether the hours are capacity constrained. In the following section, these factors will be explored and analyzed to build a picture of how often the different scenarios are applicable.

6.5.1 Approach and data source

In order to analyze the different hours and the applicable day-ahead prices and flows, data is pulled from the Nord Pool database through their website at Nord Pool Group (2019c). Data is extracted for all operating hours in 2017 and 2018 as well as all hours until the 8^{th} of December in 2019. The data includes all prices, flows and capacities for the Nordic countries and the UK. The data excludes the newer NorNed-cable, as data for this cable is not available for the entire time frame. This data is further processed using the software "R", calculating price differences between UK and NO2. The goal is to identify if flows are constrained and analyze the price differences within the Nordic synchronous area. Furthermore, the outputs are processed to be displayed and used in the following section of the analysis.

6.5.2 Capacity constrained hours and the potential constraints

The two different operating hours chosen in the analysis are distinctly different in how capacity constrained they are. The less constrained hour has less impact from implementation of new cables and FBMC, while the constrained hour is impacted to a larger degree. It is therefore interesting to analyze the distribution of capacity constraints to and from NO2, which is the connecting zone for most of the Norwegian cross-border HVDC cables. The historical load on cables compared to the capacity is used to find the available additional transfer capacity on the lines. This additional capacity, and the frequency at which they are present, is displayed for the NO2 connectors in figure 6.1.

The chosen interconnectors are the connectors from NO1 and NO5 to NO2, and the following connection from NO2 to DK1. As the export capacity from NO2 increases, the supply to this price area is very important, as NO2 would not be able to meet the entire increased demand within the production of the zone itself. In figure 6.1 one observes how the NO2 to DK1 connector is the connector that most often is constrained at the current market dynamics, with 34.7% of the hours being capacity constrained. During these hours, additional transport capacity would likely result in increased exports. However, the increased export would rather quickly increase the strain on connecting zones. As connections between NO5 and NO2 are scarce, this connection would easily be constrained with increased demand. Even the much less constrained connection between NO1 and NO2 would be capacity constrained at about 25% of the hours with a increased demand of 1500 MWh/h, which is likely with the new cross-border interconnectors.

Figure 6.1: Cumulative distribution of available transfer capacity to NO2 and on current export cable

Depending on how fast price convergence between NO2 and the connecting zones occurs, the increased export capacity of 2800 MWh/h with the new cross-border interconnectors could capacity constrain both the NO5 and NO1 connections to NO2. The result is congestion in all connections to and from the main export connection points. This is in line with the simulation results from sections 6.3 and 6.4, where capacity is constrained when exports are increase.

6.5.3 Price differences between the Norwegian price areas and the UK

In the chosen hours of operation, prices in the UK market are significantly higher than in NO2 and NO5. The differences will impact the expected demand on the NSL and NorthConnect cables to the UK. The UK price difference to Norway is more important than the German price difference, connected by NordLink. This is because the German market is to a larger degree connected to the Nordic synchronous area through DK1 and DK2 as well as to continental Europe. The convergence of prices with the UK market does in the capacity constrained hour appear quite early, at less than half of the total transfer capacity. At this time, the difference in prices is approximately 30 EUR.

As seen by figure 6.2, there is a clear trend that the prices in UK are higher than in NO2. The comparison to explicitly show NO2 here is because the differences over time between NO2 and NO5 are negligible except for specific hours. With price differences greater than 10 EUR in most scenarios and several hundred hours with over 30 EUR difference, there is a clear expectation that prices will converge for most hours, resulting in higher prices for NO2 and bordering areas.

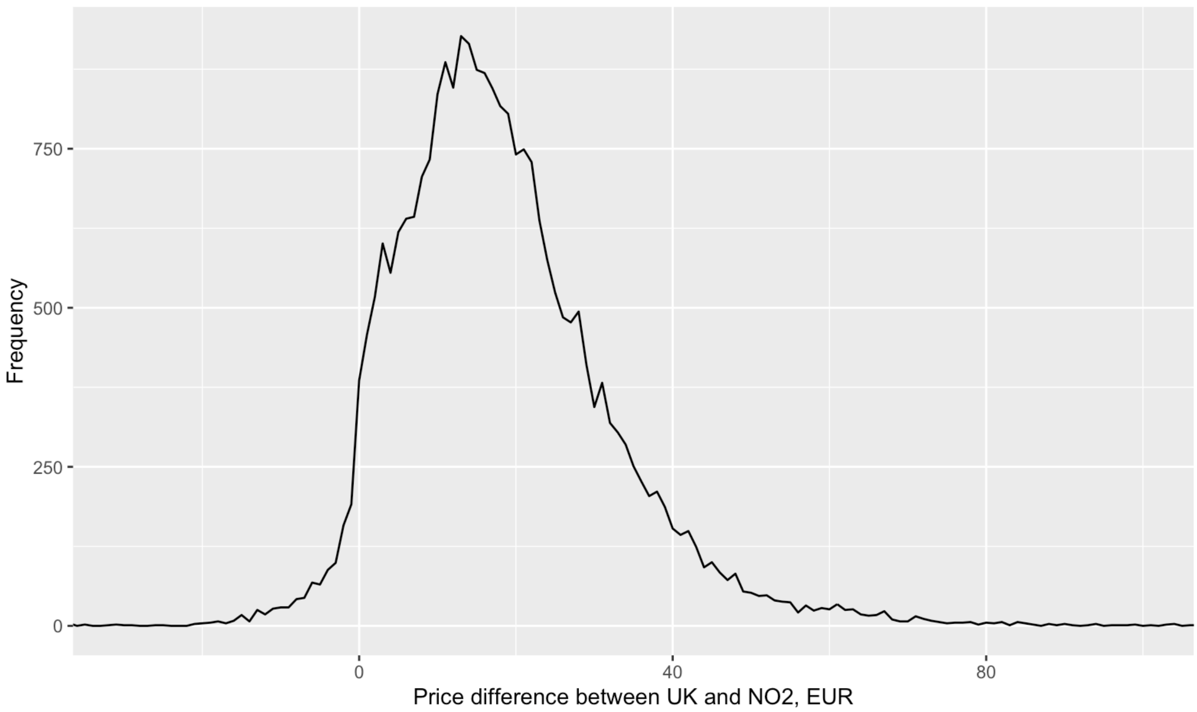

Figure 6.2: Price differences between UK and NO2 prices and the number of occurrences between 01.01.17 and 08.12.19, n = 25728.

The implications of the persistently higher prices in UK are that export cables in most cases contribute to price convergence with UK prices. The exception will be for the hours where there is surplus production capacity in NO2 and NO5 and zonal transmission capacity is available. At these hours, the difference will be rather small, even with full load on the new interconnectors, as seen in the previous example with the non-constrained hour. There will be a few hours where UK prices are lower than in NO2, but during the time sample tested here, this appears in less than 5% of the total hours. During these hours of relatively low prices in the UK, the differences are also much smaller than what they are when UK prices are higher.

7 Discussion

The following chapter will discuss the findings of the analysis and how these findings can influence the prices in the NO5 price area. Furthermore, implications of parameter definitions and its impact on the power market clearing is explored. The goal of the discussion is to display how the transition to flow-based market coupling will affect the power generators in NO5. Finally, there will be a discussion of the limiting factors to the thesis and data sources used.

7.1 Implications of cross-border interconnectors on NO5 under FBMC

The following section will discuss the different scenarios in HVDC construction and their impact on day-ahead prices in NO5.

7.1.1 Scenario 1: Impact of NordLink

With the installment of NordLink from NO2 to Germany, the prices are affected throughout the power system, and particularly in Southern Norway. However, there are large differences in how much the system is affected. As the prices are significantly higher in Germany at the selected operating hours, the entire capacity usage will result in a price increase for NO2 and its bordering zones.

For the constrained hour (03.02.17 08-09), the flow-based solution creates an approximately 30% price increase over the NO2, NO1 and NO5 price areas. The price is similar across the zones because transmission capacities in the flow-based domain are quite large and therefore not significantly constraining the capacity.

Zone	Base Case	Flow-based with NordLink	Change
NO2	33.43	45.22	35.2%
NO1	33.52	45.19	34.8%
NO5	33.69	45.13	34.0%

Table 7.1: Price change with flow-based simulation in scenario 1 - 08-09.

The construction of NordLink would lead to an increase in prices in several of the areas that have relatively low prices in the base case. This reduces the overall price differences between zones, reducing the gap to the other zones with large exports (SE4, DK2, FIN), that have significantly higher prices than NO2 and NO5 in the base case. These changes imply that Norwegian producers and consumers will experience higher prices during price sensitive hours.

For the hour with smaller differences (03.02.17 04-05), the impact of the constructed cable is less obvious. As prices are more or less the same in all zones, connections are naturally not constrained in the base case. When increasing transport capacity through the NordLink cable, the price is expected to increase, however significantly less. The price increase is expected mainly when new demand would be a shift of the demand curve, consequently changing the system price market clearing point.

Zone	Base Case	Flow-based with NordLink	Change
NO2	30.98	31.64	2.1%
NO1	30.96	31.63	2.2%
NO5	30.94	31.60	2.1%

Table 7.2: Price change with flow-based simulation in scenario 1 - 04-05.

Both of these two cases rely on the connections that connect NO2 to NO1 and NO5, as the increased demand cannot be covered single-handedly by NO2.

Comparing how the solution is different from the NTC-problem in this scenario, there are a few factors that would be applicable. As the flow is not constrained between any of these zones in either of the cases, the difference in price to NTC is expected to be rather small. There is capacity available on most lines, so the reduction in available capacity in the NTC-model does not constrain the model any further. The projected flows would necessarily be different. This could lead to differences in redispatching costs and therefore in what would be the final global optimal solution in the intraday market. As this thesis is limited to the day-ahead market, redispatching and the impact of it is not explored further.

7.1.2 Scenario 2: Impact of NordLink and North Sea Link (NSL)

Expanding NO2-connection further does in fact increase the demand for power in southern Norway to a larger extent. The North Sea Link between the United Kingdom and NO2 will increase demand to the point where prices converge between the Norwegian price areas and the United Kingdom, which at the constrained hour would be at approximately 60 EUR/MWh. The NSL connection exposes Norwegian price areas to the British market and its demand for electricity.

At the constrained hour, the demand for relatively cheap Norwegian power is so great that convergence is inevitable. The impact of price convergence is that export on the NordLink and NSL cables are unable to reach full capacity. The simulations identify a price convergence with the British and German prices at a total export of 1700 MWh/h. This export is significantly lower than the total export capacity of 2800 MWh/h, so any supply increase for NO2 and bordering zones would immediately result in increase exports to UK and Germany.

Zone	Base Case	Flow-based with NordLink & NSL	Change
NO2	33.43	58.02	73.6%
NO1	33.52	57.96	72.9%
NO5	33.69	57.86	71.7%

Table 7.3: Price change with flow-based simulation in scenario 2 - 08-09.

At this point, the connections between NO2 and NO1 & NO5 are on the edge of what they are capable to transport. The flow-based methodology is crucial in providing the opportunity to fulfill more of the external demand. As seen in following table, NTC capacities are substantially lower than the extended flow-based solution domain.

Connection	Flow-based Domain	NTC Domain
NO5 -> NO2	1547	930
NO1 -> NO2	2207	2121

Table 7.4: NO2 connection capacities, in MW (Nordic RSC, 2019b).

The difference in domains between the NTC and FB methodologies would be of significant importance when NO2 exports are greater than 1700 MWh to the UK and Germany.

With the NTC solution, one would expect NO2 prices to be more similar to the other zones with large exports, where bordering zones see less change since they are limited by their export capacity. In particular, the connection from NO5 is so narrow in the NTC domain that the capacity would be constrained at even a moderate increase of demand.

For the unconstrained hour, the case is quite different. Most zones have little to no congestion, leaving room for significantly larger exports. As seen from the table below, prices increase only slightly, even when exporting 2800 MWh. The UK prices are high also at this hour, incentivizing the UK to import as much as possible. This, however, does not push the price more than a few percent in Norway as it only shifts the market clearing point and system price.

Zone	Base Case	flow-based with NordLink & NSL	Change
NO2	30.98	32.20	3.9%
NO1	30.96	32.19	4.0%
NO5	30.94	32.16	3.9%

Table 7.5: Price change with flow-based simulation in scenario 2 - 04-05.

Comparing the FBMC-solution to the NTC domain, the increase in overall transmission capacities become more important as they are pushed to the limit. Even though exports are high in this scenario, the capacities between the Norwegian zones are not constrained in this solution. The increased domain from the FBMC solution creates a larger margin, but as the NTC capacities would be sufficient at this hour, the price impact of the different solutions is expected to quite small. The difference between FMBC and NTC in the day-ahead market for this type of hour is not expected to be significant.

7.1.3 Scenario 3: Impact of NordLink, North Sea Link (NSL) and NorthConnect

When adding the final projected interconnector, the NorthConnect cable between NO5 and the United Kingdom, the case with the constrained hour is no longer expected to change. Prices do not change because the entire Norwegian network was constrained in the previous scenario. While one could expect some of the transport of electricity to be over the NorthConnect cable, there would still be price convergence at the same price point with the the United Kingdom zones.

The unconstrained hour is however quite different. When the export capacity is increased with an additional 1400 MW, the export from Norway to UK and Germany reaches a total of 4200 MW over the three new HVDC cables. Similarly to the previous cases, the market clearing point and system price is shifted, resulting in an increase in price. This increase is reflected in the table below.

Zone	Base Case	Flow-based with NordLink, NSL and NorthConnect	Change
NO2	30.98	32.89	6.2%
NO1	30.96	32.87	6.2%
NO5	30.94	32.85	6.2%

Table 7.6: Price change with flow-based simulation in scenario 3 - 04-05.

The NorthConnect cable changes the pressure on the transmission system in southern Norway. While the previous cables connect to NO2 and pressure the transmission lines connecting NO2 to NO5 and NO1, the NorthConnect cable will be able to shift demand to NO5. In the cases presented, there is little to no price difference to be expected from this change, but the capacity limitations shift. Because the connection from NO5 to NO1 is pressured in the previous cases, this line could experience reduced load and more flexibility.

Comparing this solution to the NTC domain, the impact of FBMC will be lower in this case. As lines will be experiencing reduced load, the expanded domain of the FBMC calculations are less important. In fact, the NTC capacities could be sufficient to maximize output from this cable in combination with the previously implemented cables. Therefore, in the third and final scenario, differences between NTC and FBMC optimization is expected to be lower than in the previously simulated scenarios.

7.1.4 Summary of impact of HVDC-connections to the electricity prices in Norway

The construction of new cross border interconnectors to UK and Germany does in all of the tested scenarios result in price increases in NO5. The price increases with the number of cables and increased export capacity, primarily because the prices in the UK and Germany are higher than in Norway during the selected hours. This increase depends on the characteristics of the selected hours, where a capacity constrained hour leads to significantly larger price differences than in an hour with less load.

These findings would vary with selected hours. However, analyzing some of the extreme cases creates a frame with a ballpark of how changes in electricity prices would be with flow-based market coupling. While prices surges of $> 70\%$ would be few and far apart, the increases are slightly mitigated with flow-based market coupling and shared more evenly between zones. For NO5, the increase in prices would in most cases result in more exports to NO2, as NO2 would be the main connection point for most of the external demand and load.

Comparing the FBMC solutions with the NTC domain, there are a few aspects to make note of. For the cases discussed in this thesis, the increased FB-domain is impacted differently depending on the selected hours and case characteristics. The key question addressed is whether increased transmission capacities will impact the solution and prices in the simulations. For several of the cases, NTC capacities are sufficient for optimal power transfer. For the most constrained cases, however, the FBMC capacities allows for a better use of the transmission grid. On the other hand, it is challenging to conclude whether the flow-based solutions are superior to the NTC solutions. As this thesis limits to the day-ahead solution and does not account for redispatching costs, the final verdict on whether or not the FBMC approach is objectively better is not possible to make. Additionally, with construction of cross-border HVDC cables, one can expect the connection points for these cables to be significantly harder loaded than as of today. This change would most likely change internal CNEs and the relevant PTDFs, consequently changing the optimization problem.

7.2 Implications of FBMC on actors in the NO5 electricity market

As seen in the previous section, implementation of HVDC connections to UK and Germany does in all tested scenarios lead to increased prices in NO5. Especially with the constrained scenarios with high demand, NO5 will see a greater price increase compared to NTC scenarios where capacity to NO2 would be limited.

7.2.1 Impact on power generators in NO5

Generators in NO5 mainly consist of hydropower plants with flexible production capabilities (Norwegian Energy Regulatory Authority, 2019a). These producers have the opportunity to choose when to produce power and when to hold back water in the reservoirs. This flexibility enables NO5 producers to take advantage of price differences and changes. Their flexibility is best applied in the more constrained hours, where export capacities are at a maximum. At these times, the NO5 producers would be able to increase production at a decent cost while obtaining increased revenues. Similarly, the producers could hold back and fill reservoirs in times of lower pricing, allowing to import cheaper non-flexible power from the continent.

With the implementation of flow-based market coupling, the difference in prices is expected to be smaller, but more often (Helseth, 2013). The impact of this is that producers can have more sustainable and less risky reservoir management. With more frequent changes, the risk of having to produce at cheap prices and risk of over-producing at expensive pricing is reduced. Additionally, with the increased capacity to power-exporting zones such as NO2 and NO1, the possibility to exploit price changes is further increased.

However, the ability for producers to predict and plan is greatly reduced with the increased uncertainty of the flow-based model. As discussed earlier, the current methods of calculation in the Nordic RSC is extremely challenging to replicate in a meaningful way with the currently available information. Although producers could access some of the currently classified information, such as grid connections from producing plants, it is not likely that a reproduction of the flow-based model will be feasible in a prediction environment. The Nordic RSC is working on a stakeholder tool that could facilitate the flow-based calculations (Nordic RSC, 2016). At the moment in which this thesis is written, however, the tool is far from applicable to real life scenarios and has remained unchanged since December 2016. As long as the details of PTDF-calculations are unavailable, accurate prediction is most likely unfeasible.

Low predictability impacts producers in several ways, and especially in investment and expansion decisions. When evaluating whether a construction or expansion is worth the investment, the way the connected lines will be affected is highly relevant. The network must be able to handle the increased loads of the potential production of these plants in for the investment to be justified. With FBMC, these implications are harder to assess if inter-zonal CNEs are anonymized. Although the guideline for congestion management by European Commission (2015) is relatively clear on how inter-zonal CNEs should be determined, it is more unclear in whether and how TSOs or other service providers should publish these CNEs and at what level of detail they should be published.

In the simulation data provided by the Nordic RSC, the basis of the analyses in this thesis, zone-internal CNEs are completely anonymized. It is not possible to identify the CNEs to their actual corresponding elements in the actual grid. They are also anonymized for each hour, meaning that it is impossible to follow the properties of a particular CNE between different operating hours. When CNEs cannot be identified, they may or may not be in close relation to any of the projected generation plants. Moreover could the construction or expansion of a plant introduce new CNEs and in that way change how the entire PTDF-calculations are conducted. Without available on information on how these factors are effected, investment decisions become extremely challenging. The lack of necessary generation investment can also affect other stakeholders in the power market in terms of, for example, security of supply or price levels for consumers.

While the impact of low transparency is a general remark for all zones, the degree of its impact depends on what type of generation is constructed. When the cost of a construction project is high, it intuitively requires larger certainty in the investment decision in order to mitigate the related risk. With the increasing cost of production of hydropower (International Renewable Energy Agency, 2019), one would expect new construction of hydropower to be less likely than before. This uncertainty adds to the increased resistance against new hydropower plants as they are often seen as interventions in nature. Similarly, wind power has experienced resistance in the Norwegian political environment, which increases the difficulty of constructing these plants. Some international markets operate with feed-in tariffs, a price guarantee from the government for a large share of the producing assets lifetime. Norway has no feed-in tariffs and therefore the uncertainty compared to other countries increases further (Knoema, 2019).

7.2.2 Distribution of constrained hours implications for NO5

The new cross-border interconnectors will most likely be drivers for congestion between NO2 and bordering zones. They are also likely to drive up NO5 prices and lead to a price convergence towards the UK power market. As seen by figure 6.1, the NO5 connections to NO2 will be congested at a quite early time because their transmission capacity is scarce. However, transmission via NO1 would be possible for significant amounts of production.

With the construction of the NorthConnect cable directly from NO5, the increase in prices will be shared between zones. NO5 will be driving price convergence together with NO2, increasing opportunities for NO5 producers. With flow-based market coupling and increased transmission capacities, these implications are expected to be pushed further. In certain operating hours, the UK prices are lower, but these hours are not significant in the big picture, as they are few and far apart as well as small in value. A possible long term consequence is that prices will be driven up, also in the hours with little price difference. The reason is that one would expect lower Norwegian reservoir levels when there are large opportunities to export electricity and reduce the saved reservoir levels.

7.3 Implications of FB design parameters on NO5

Previously in this thesis, an explanation of the parameters in flow-based market coupling calculation has been provided. An analysis of its implementation and the discussion of the results is then presented. This section will elaborate on how the selected flow-based design parameters in the Nordics will affect the market solution, with particular emphasis on Generation Shift Key (GSK) strategies and the NO5 bidding zone.

7.3.1 Impact of selected GSK strategies

As discussed in chapters 3 and 4, the selection of generation shift key strategies can have a significant impact on the flow-based market clearing solution (Marien et al., 2013). The Nordic TSOs determine their GSK strategies according to the criteria explained in chapter 4 as presented by Nordic RSC (2019c). The TSOs have synthesized these criteria to a list of nine possible GSK calculation methods for the Nordic region. The nine GSK strategies are mathematically described in appendix A2.

The first GSK strategy, 0, is a custom strategy for one particular hour. Strategies 1-5 weighs the nodal PTDFs according to production, while GSK 6 uses a combination of both production and load weights. GSK 7 and GSK 8 weigh according to the load, which is generation adjusted for net export. In the initial analyses of the Nordic RSC and the Nordic TSOs, a flat GSK strategy is selected, i.e. GSK strategy 4 and 8. However, they are currently exploring different GSK strategies and aim to study the effect of different GSK selection on the FBMC market solution. (Nordic RSC, 2018).

The results of the GSK evaluation process is of great importance to the success of the flow-based method in the Nordics. The selection and harmonization of suitable GSK strategies are crucial in order to avoid harmful incentives and to insure transparency in the capacity calculation process (Marien et al., 2013).

For the market simulations conducted by the Nordic RSC, and hence the basis of the analysis presented in this thesis, GSK strategy 6 has been selected for all bidding zones (Nordic RSC, 2019c). This GSK strategy weighs the nodal PTDFs according to both load and production, relative to the actual current power generation or load. The Nordic RSC does not seem to provide an explanation for why GSK 6 is selected. However, it is likely because GSK 6 is the only strategy that weighs after both generation and load, serving as a "middle ground" between zones with relatively high production and consumption, respectively. Since the optimal GSK strategy can be significantly different across bidding zones, a common GSK strategy is likely to be sub-optimal for certain zones.

Based on the definition of GSKs, zonal PTDFs and RAM as presented in chapter 4, the selection of GSK 6 has clearly impacted the simulation results for NO5 and in general. The following section will provide a general discussion on factors that should be considered when determining an optimal GSK strategy for the NO5 region and why it is of relevance. The purpose is not to identify optimal GSK strategies, but to emphasize their importance when implementing FBMC in the Nordics.

7.3.1.1 Principles for optimal GSK strategy determination in NO5

As presented in chapter 2, there are several large hydropower production plants in the NO5 zone (NOU 2019: 16., 2019). In the western part of NO5, where production is high and demand is scarce, the power generation is usually notably higher than the load (Svarstad, 2016). These characteristics speak in favor of a GSK strategy largely based on generation units. However, the relative power generation in the eastern NO5 region is substantially higher than in the western part due to the lack of significant consumption in the east. In the western part, there is a considerable load due to the power consumption of industry and households.

If the western NO5 were a separate region, the GSK 6 would probably be more suitable because it takes both generation and load into account. Hence, two different GSK strategies are likely to be optimal for the two parts of the bidding zone. The Nordic TSOs should therefore reconsider the bidding zone configuration of NO5 and the other zones when implementing flow-based market coupling. This is in line with the findings of Marien et al. (2013) and Van den Bergh et al. (2016) presented in chapter 3. They argue that smaller and more numerous zones provides a better representation of the physical characteristics of the power grid, which leads to lower FRM and reduced uncertainty.

According to the analysis and findings in chapter 6, the transformation to flow-based market coupling in the Nordics will generally lead to higher prices in Norway, due to higher expected exports. In particular, the power transfer from NO5 to NO2 will increase due to higher utilization of the interconnectors. Furthermore, new HVDC interconnectors will increase the power exported from the NO5 region. The price difference between the UK and NO5 is more than 10 EUR for more than 80% of the analyzed operating hours, which will lead to an almost full utilization of the cross-border interconnectors. In sum, these effects are likely to increase the power generation, relative to power load, in the NO5 region. The export is also facilitated by the high degree of flexibility of the hydro power plants in NO5. As net export increases, the optimal GSK strategy is more likely to be more generation-driven.

With GSK 3, the weight will be allocated according to the maximum generation capacity, essentially causing the larger production plants to have a greater influence. This strategy is therefore likely to be suitable for the NO5 region. GSK 5 gives a weight according to the actual production and is therefore suitable in areas with a large amount of flexible power production and high exports. GSK 5 is therefore also likely to be suitable for the NO5 region, particularly as its export increases.

A flat GSK strategy, as initially used by the Nordic TSOs, is doubtfully an ideal strategy for the NO5 region. Although it is easy to implement as it only needs to be calculated once, it treats every node as generating. In cases where the generators vary in size, such as in NO5, this will lead to an underweighing of large generators and overweighing of smaller generators. Furthermore, a flat strategy does not take into account changes that can occur in the net position due to for example a change in net exports or in the power balance of a node. Due to the large exports from NO5 and its high degree of flexible production, a dynamic GSK strategy is likely to be more suitable. This argument is likely to be strengthened as the new cross border interconnectors are set in operation. Additionally, the strategies should be dynamic in time in order to account for seasonalities and variances due to peak and off-peak hours. Such intertemporal changes in power balances are also likely to be affected by the flow on the cross-border interconnectors and the power balance in connected markets.

7.3.1.2 Implications of suboptimal GSK strategies and the responsibility of regulators

As discussed above, a suitable GSK strategy must be in place in order to utilize the full potential of the flow-based market coupling methodology in the Nordics. Statnett, the Norwegian TSO and the responsible actor for determining the GSK strategies in Norway Nordic RSC (2019c), must carefully and continuously assess different strategies for the five Norwegian bidding zones. Their considerations should be based on both the regulations made by the European Commission (2015), the assessment and GSK strategies of the other Nordic TSOs, as well as the specific characteristics of the individual Norwegian regions.

Furthermore, the future cross-border interconnectors are likely to significantly impact the power balance in several Norwegian bidding zones. Therefore, Statnett should take the projected impact of these cables into account when determining the strategies. In order to mitigate the issue of circular dependence in GSK determination, as explained in chapter 3 and Marien et al. (2013), the TSOs must improve the quality and capacity of their forecast simulations. With increased data power and the utilization of predictive analytics tools, analyses can be conducted for a larger amount of strategies in all zones for several operating hours. If the exogenous variables that impact the GSK strategies and the power prices can be predicted with a higher certainty, the simulated GSK strategy can give a closer representation of the actual power balances.

A GSK strategy that poorly represents the actual grid will provide an inaccurate linearization of the power flow in a zone and inaccurate zonal PTDFs. Poorly defined GSKs can therefore increase the need for a higher FRM on certain CNEs, or remedial actions, thus reducing the effectiveness of the FBMC (Marien et al., 2013). Setting these parameters correctly will be particularly important for the NO5 and NO2 regions due to its large exports and ever-increasing connection to other power markets. As our analyses show, a high utilization of the interconnectors will be beneficial for the overall market solution in the Nordics, which again is facilitated by well-defined FBMC parameters. Note that these analyses were based on parameters defined by the Nordic RSC, including the selection of GSK 6. Although it is hard to quantify the impact of how these parameters are defined, the Nordic and European TSOs should continue to explore and evaluate different parameters in order to allow for an optimal FBMC market solution when the model is implemented in the Nord Pool area.

As the German and UK power markets become increasingly connected with the Norwegian and Nordic markets, a closer cooperation between the Northern European TSOs should find place. One potential benefit of cooperation is avoiding that GSK selection leads to the disfavour of certain areas or reduction in overall social welfare when taking the entire market into account. Moreover, the communication and collaboration between relevant TSOs can be done through the fora of the ENTSO-E, which is set to facilitate the technical cooperation between European TSOs (European Network of Transmission System Operators, 2015). The ENTSO-E has a regulatory mandate by the EU and can act as a regulator to ensure monitoring and transparency of the individual TSOs when the flow-based parameters are defined.

7.3.2 The impact of reference flow determination

All design parameters influencing the determination of the remaining available margin will be relevant when FBMC is implemented in the Nordics. As explained in chapter 4, the RAM is reduced by the $Fref'$ parameter, which represents the grid capacity occupied by internal trades in a particular zone. In other words, when the reported pre-booked internal capacity increases, the RAM decreases, leaving less available capacity for potential cross-border trade. In our assessment of the suggested flow-based methodology, we find that the $Fref'$ parameter can cause incentives for generator decisions that are unfavorable for the overall socioeconomic benefit in the market. This issue will be explained with a hypothetical example.

Consider a large bidding zone, zone Z, with large internal differences in power balances and prices. This can for example occur when there is relatively large power generation in one part of the zone, and relatively large power consumption in the other. If the power prices in bordering bidding zones are sufficiently low, it might be beneficial for the power generators in the zone Z to sell to customers internally in the zone, rather than in the day-ahead market where flow-based market coupling is utilized. In this case, the generators in zone Z will benefit from increasing the reported level of pre-booked capacity and hence the $Fref'$ in their bidding zone. If the $Fref'$ is set artificially high, this will reduce the RAM from its optimal level and cause a lower utilization of the power grid, in turn leading to a lower socioeconomic benefit for the region.

The risks related to opportunistic parameter determination are partly mitigated by the new regulations presented in recommendation No 01/2019 by ACER, the Agency for the Cooperation of Energy Regulators (2019). The EU recommendation determines that RAM shall be set minimum 70% of the $Fmax$, the maximum thermal limit of a CNE. A result of this lower limit can be that the generators in zone Z attempt to lower the $Fref'$ in order to obtain the minimum RAM-level of 70%. If this limit is not met, remedial actions, such as redispatching, may be demanded by regulators. This can be costly for both generators and consumers.

The case presented above is intuitively not representative for the NO5 price area. The zone is normally a net exporter of power and the NO5 generators will generally benefit from cross-border trade. The export is likely to increase with increased cross-border transfer capacity from the Norwegian power market, according to our analyses. Whether the NO5 generators will benefit from manipulating parameters in order to increase the RAM levels, and thus the available cross-border transfer capacity, will depend on a range of other factors that limit the maximal available power flows. The incentive to manipulate RAM levels is also relevant for the other parameters that affect RAM levels, such as the FAV and $Fmax$.

Regardless of the NO5 case, it is recommended that Nordic TSOs and relevant energy regulators evaluate how all FBMC parameters are defined and affected in order to prevent obscure incentives and harmful decisions by power generators and other relevant players in the market. In other words, it is not only crucial to evaluate how FBMC design parameters affect the success of FBMC implementation, but also evaluate how the incentives of specific actors affect this success. These analyses should moreover assess the effect of fundamental changes in the Nordic power market, such as changes in the power mix and structural changes in the grid.

7.4 Limitations of the thesis

In the following section, the possible shortcomings of the data, as well as limitations in model, approach and findings will be discussed.

7.4.1 Limitations of data

The main source of data for this thesis are the flow-based market coupling simulations as conducted by the Nordic RSC in Q1 2017. There are several possible implications of this dataset, some of which are highlighted in the previous sections. One obstacle is that the zone-internal CNEs are anonymized, which decreases transparency and reduces the ability to reconfirm the findings of the Nordic RSC. Additionally, the parameters chosen by the Nordic RSC must be taken as given, as the zonal PTDF-matrix would be impossible to recreate based on available data. Parameter definitions are important for the outcome, which is discussed in section 7.3. Finally, the age and selection of data is not optimal because the data is limited to three months in early 2017. There has been changes to both transmission lines and power production since then. As a result, updated data could provide more accurate insights to the effects and their implications.

Furthermore, the bid curve data from Nord Pool has severe limitations. As discussed in section 5.3.2.2, the bid curves from Nord Pool are only available on a system level for the entire Nordic area, including the Baltic countries. The disaggregation of these bid curves is associated with large uncertainties and is not expected to be close to the true demand and supply curves. This is due to the method of dividing bid curves by volumes alone. As each zone has a different composition of cheap and expensive production, one would expect sensitivities to differ between zones. Bid curves on a zonal level would increase the precision and validity of the outcomes as they would be a true representation of supply and demand. Even further, demand on a nodal level would be necessary to replicate the PTDF-calculations from Nordic RSC. Finally, while the Nord Pool data is quite specific in its definitions, the geographic areas covered vary in whether it includes the Baltic countries or not. The data for Baltic area could skew the results even though their share of total volumes are subtracted from the analysis, as their bid curves are most likely not perfectly defined by the system bid curve.

Finally, the choice of operating hours impacts the outcome of the analysis to a large degree. This thesis only focuses on two specific operating hours out of the several thousand hours available. Doing the analysis over time for more hours could increase the insights and nuances of the discussion. Additionally, analyzing more moderate hours might provide different results.

7.4.2 Limitations of model and analysis

There are certain shortcomings associated with the implementation of the simulation model. Firstly, the challenges in implementing HVDC cables in the flow-based model impact output to a great degree. As discussed in section 5.3.2.1, the HVDC cables are implemented with Advanced Hybrid Coupling in the Nordic RSC simulations (Nordic RSC, 2019c). The simulation model used in this thesis, however, does not implement AHC, and flows on HVDC cables are rather set to a fixed level. As a result, flows on HVDC cables within the network are not represented accurately.

Secondly, the implementation of new cables is done by shifting demand curves. However, the demand in the connected zones naturally would be relative to the price with their own bid curves. If the connected zones were implemented with bid curves, their flow would probably be more accurately simulated, resulting in more accurate prices.

Finally, this thesis does not create an apples and apples comparison of NTC and FBMC in the model. This is because the implementation and limitations of HVDC cables and their effect does not translate between the models, and results would be non-comparable. The missing direct comparison reduces the ability to definitely conclude on the effect of FBMC compared to the current NTC approach.

Moreover, the simulation results must be read with caution as several factors would impact the real scenarios in the future. Firstly, the total impact of cross-border interconnectors are presumably larger than a simple increase in demand (Hernes and Bruvik, 2018). One would, for example, expect that CNEs and PTDFs would change when a high demand cable is connected to the power grid. This would fundamentally change the output from the model.

Secondly, more interconnection capacity can alter the behaviour of consumers and producers. Increased transfer capacity could for example stimulate the construction of additional capacity or alternative energy sources. As a consequence, the bid curves and the characteristics of the power grid can change substantially over time. Finally, the FMBC approach that is applied by the Nordic RSC and in this thesis is preliminary (Nordic RSC, 2019c). The final version of FBMC, the one that will be implemented in the Nordics, is not yet determined. The methodology might change significantly throughout the testing period and parallel runs, impacting outcome of FBMC simulations.

Lastly, this thesis solely simulates and evaluates the day-ahead power market. The omission of the intraday market from the analysis and discussion is an important limitation of this thesis. While the day-ahead market is widely used in financial markets, as well as in capacity planning, the true efficiency of the market coupling approach will not be visible. Only through analysing the redispatching cost and intraday market implications can one determine if the approach chosen truly is better in socioeconomic terms.

8 Concluding remarks

This thesis aims to shed light on how the the planned transition to flow-based market coupling will affect the Nordic power markets. A specific focus is placed on the impact on prices in NO5 and the impact for generators in this price area. In order to address this issue, an optimization model for the Nordic power market is built and relevant research and literature is explored. The focus is to evaluate the impact of flow-based market coupling on the Nordic power market and how it differs from the current market clearing model.

The market simulation model uses the data from the Nordic RSC flow-based market coupling simulations, as well relevant market data provided by Nord Pool. Furthermore, the effect of additional transport capacity through planned cross-border interconnectors is analyzed. The purpose of this scenario-based analysis is to evaluate how the future interconnectors will affect the market with flow-based market coupling. Additionally, the distribution of price differences and congestion over time is analyzed to elucidate the extent of the simulated scenarios. Finally, this thesis explores how regulators and generators impact the outcome of the flow-based market coupling through definition of parameters and transparency in methodologies.

The results from the conducted analysis imply that cross-border interconnectors will, generally, raise day-ahead power prices in the Nordic area. The prices in the UK and German market are higher than the Norwegian prices for most hours, with large price differences in a significant amount of hours. This, coupled with production flexibility and good internal transmission in southern Norway, lays way for price increases in Norway. The impact of the flow-based market coupling in these scenarios varies by the congestion on the network. When the Norwegian network is more congested and in hours of great price differences, prices converge between UK and NO5. This happens due to a full convergence in prices prior to a full load on the exporting cables.

At less congested hours, it is not clear whether flow-based market coupling would affect prices. As lines get more congested, the increased capacities in the flow-based market coupling simulations enables more exports and better utilization of the transmission grid. The increase in capacity from the flow-based methodology stands true for the hours and scenarios analysed in this thesis. However, this might not be a case for every single operating hour and simulation strategy. The importance of flow-based market coupling capacities decreases as the final cable from NO5 to UK, NorthConnect, is added. This cable offloads the connection between NO5 and NO2, as well as the rest of the Nordic network.

Generators in NO5 would be impacted in several ways, in addition to a pure price effect. Firstly, the lack of transparency increases uncertainty for generators and represents a great challenge with flow-based market coupling. This uncertainty will impact a generators' ability to conduct efficient business planning, as well as their ability to accurately value investment decisions. The increased investment uncertainty is likely to be accompanied with significant political risk. The abovementioned effects can reduce the the attractiveness of plant construction in Norway, in turn affecting several stakeholders in a negative manner.

Finally, the parameters chosen by regulators are key to how flow-based market coupling affects generators in NO5. The currently chosen GSK strategy is likely sub-optimal for both the Nordics in general and NO5 in particular. Inaccurate calculations impact generators through less optimal planning and grid utilization, resulting in reduced revenues through costly redispatching. Generators must work with TSOs to ensure that optimal bidding zone configuration and design parameters strategies are chosen. Moreover, the parameters must be designed in a manner that limits possible opportunistic behaviour of power generators and other actors in the Nordic power market. This is critical to ensure that the implementation of flow-based market coupling reaches its full potential in terms of total socio-economic benefit.

To further explore this topic, future analyses should include the ELBAS intraday market and the costs of redispatching. Secondly, by using several operating hours and other scenarios, more accurate results can be presented. Lastly, further research should be conducted on the full impact of FBMC design parameters for the Nordic power market.

While the overall impact of flow-based market coupling is unclear, generators in NO5 are expected to be better off. This is achieved through better pricing, greater export capacity and better use of available transmission grid. However, the producers would experience increased uncertainty, and it is critical to work closely with regulators to ensure that the implementation is done in the most optimal way for all actors involved.

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Appendix

A1 Current, future and planned cross-border interconnectors in the Nordics

Countries	Name of cable(s)	Year	Status	Capacity
Norway-Sweden	8 cables		Active	3200-3600
Norway-Denmark	Skagerak 1-2	1976-77	Active	510
Norway-Denmark	Skagerak 3	1993	Active	530
Norway-Denmark	Skagerak 4	2014	Active	700
Norway-Netherlands	NorNed	2008	Active	700
Norway-Finland	Varangerbotn-Ivalo		Active	70-120
Norway-Russia	Kirkenes-Borisoglebskaya		Active	50
Sweden-Finland	Fennoskan 1	1989	Active	500
Sweden-Finland	Fennoskan 2	2011	Active	800
Sweden-Germany	Baltic Link	1994	Active	600
Sweden-Poland	SwePol	2000	Active	600
Sweden-Lithuania	NordBalt HVDC	2015	Active	700
Denmark-Sweden	Kontiskan 1	1965	Active	250
Denmark-Sweden	Kontiskan 2	1988	Active	300
Denmark-Germany	Kontek	1995	Active	600
Norway-Germany	NordLink	2020	Under construction	1400
Norway-UK	NorthSeaLink (NSL)	2021	Under construction	1400
Denmark-Germany	Krieger's Flak	2020	Under construction	400
Denmark-Netherlands	CobraCable	2019	Under construction	700
Sweden-Germany	Hansa Power Bridge 1	2026	Under consideration	700
Sweden-Germany	Hansa Power Bridge 2	2030	Under consideration	700
Norway-UK	NorthConnect	2022	Under consideration	1400

Table A1.1: Current, future and planned cross-border interconnectors in the Nordics. Capacities in MW. Current cables are retrieved from (European Network of Transmission System Operators, 2019) and future and planned cables are retrieved from (of Transmission System Operators, 2019).

A2 GSK strategies

Strategy number	Generation	Load	Comment
0	k_g	k_l	Custom GSK strategy with individual set of GSK factors for each generator unit and load for each market time unit for a TSO
1	$max(P_g - P_{min}, 0)$	0	Generators participate relative to their margin to the generation minimum (MW) for the unit
2	$max(P_{max} - P_g, 0)$	0	Generators participate relative to their margin to the installed capacity (MW) for the unit
3	P_{max}	0	Generators participate relative to their maximum (installed) capacity (MW)
4	1.0	0	Flat GSK factors of all generators, independently of the size of the generator unit
5	P_g	0	Generators participate relative to their current power generation (MW)
6	P_g	P_l	Generators and loads participate relative to their current power generation or load (MW)
7	0	P_l	Loads participate relative to their power loading (MW)
8	0	1.0	Flat GSK factors for all loads, independently of size of load

k_g: GSK factor (p_u) for generator g
k_l: GSK factor (p_u) for load l
P_g: Current active generation (MW) for generator g
P_{min}: Minimum active power generator output (MW) for generator g
P_{max}: Maximum active power generator output (MW) for generator g
P_{load}: Current active load (MW) for load l

Table A2.1: GSK strategies in the method proposal by the Nordic TSOs (Nordic RSC, 2019c).

A3 Nordic RSC quantitative impact assessment

This subsection presents the overview of the assumptions applied in the flow-based capacity calculation simulation conducted by the Nordic RSC and the Nordic TSOs. The list is an exact representation of section 11.1 *Quantitative impact assessment* in the technical document *Stakeholder consultation document and Impact Assessment for the Capacity Calculation Methodology Proposal for the Nordic CCR* by Nordic RSC (2018). These assumptions are likely to impact the results presented in this thesis.

Reliability margin

For the (thermal) CNEs an FRM = 0 has been applied. The (voltage and dynamic stability) cuts in the Nordic system – they are computed by the local TSOs in their local tools, by using their local grid models – are provided as an input to the FB capacity calculation, like they are to the local NTC capacity calculation. This holds true for the TRMs on those cuts as well: the same value is applied in both the FB capacity calculation as well as in the operational NTC capacity calculation. The difference for cuts (compared to the operational NTC capacity calculation) only comes into play when the FB capacity calculation assesses the PTDF factors for the cuts, and takes into account the reference flows, to assess the RAMs on the cuts. As the Nordic system is mainly limited by those (voltage and dynamic stability) cuts, the assumption of having an FRM = 0 on the (thermal) CNEs is not expected to severely impact the quantitative results.

Operational security limits

Please note that the FB capacity calculation is not an operational procedure yet. Although operators are consulted in the review stage, they are not personally involved in the FB capacity calculation process yet. The operational security limits applied in the FB capacity calculation, are the same as the ones applied in the current NTC capacity calculation, and are likely to be the ones to be applied in the FB operational process as well.

Contingencies

n-1 outages are taken into account for the thermal limits (CNEs) , and are the ones to be applied in the FB operational process as well.

Allocation constraints

The allocation constraints applied are the same as applied under the operational NTC capacity calculation and allocation. The allocation constraints consist of the implicit loss factors of DC links only (ensuring that the DC link will not flow unless the welfare gain of flowing exceeds the costs of the corresponding losses), for those DC links where this has been implemented, and maximum flow change on DC-links between MTUs (ramping restrictions).

Generation shift keys

One common GSK strategy has been applied for all bidding zones in the FB capacity calculation. This is strategy number 6, as mentioned in Table 8-1.

Remedial actions

Remedial actions have been applied in the form of FAV values, which might also include additional adjustment values in addition to RAs. For Norway, automatic response systems where load, generation, HVDCs or other grid components are automatically disconnected or adjusted, are reflected by the FAV values. The FAVs are applied both to cuts and CBCOs.

Undue discrimination between internal and cross-zonal exchanges

The grid constraint selection process, as described in Section 6.2, is applied with a threshold value of 15

Previously allocated cross-zonal capacity

No previously allocated capacity has been considered in the DA FB capacity calculations.

PTDF distribution factors

The FB parameters are computed in a commercial software tool, that has been set up by the Nordic TSOs, and enhanced by scripts, for the FB capacity calculation purposes. Both the PTDF factors for cuts and CNEs are computed by this prototype tool.

Remaining available margins on critical network elements

The remaining available margins are computed in a stepwise manner: RAM = Fmax – FRM – Fref' ± FAV. The Fmax values are set by the TSOs: they are physical properties for the grid constraints, whereas they are computed for the (voltage and dynamic stability) cuts in the Nordic system (by the local TSOs in their local tools, by using their local grid models). The FRMs are set by the TSOs as well (see the first bullet on reliability margin).The Fref (being the basis for the Fref') is computed from the prototype common grid model (CGM) in the same software that computes the PTDF factors. The FAV is set by the TSOs, depending on the application of remedial actions.

CGM

The prototype CGM is used for the computation of the PTDFs, and the Fref (being the basis for the Fref'). The quality of the prototype grid models is the best we can have at this moment in time; they do not allow for dynamic analysis and detailed voltage/reactive power analysis though.

Sharing of power flows between CCRs

No sharing of power flows between CCRs is applied. Indeed, the so-called advanced hybrid coupling is being applied in the FB capacity calculation and allocation. The converter stations of the DC interconnectors are modelled as 'virtual' bidding zones in the FB system (a bidding zone, without order books though), having their own PTDF factors reflecting how the exchange on the DC link is impacting the AC grid elements. Or in other words: the flows on the DC links are competing for the scarce capacity on the Nordic AC grid, like the exchanges from any of the other CCRs.

Failures in the FB capacity calculation

Mainly because the prototype CGM poses some challenges, for some of the hours (6 FB capacity calculation no FB parameters can be computed. For these hours, in the capacity allocation simulation, the FB parameters are replaced with the operational NTC values of those hours. The future operational CGM and FB process are more robust. In the rare case that no FB parameters can be computed a proper fallback solution needs to be in place.

Market simulations

The FB market coupling simulations are done in the European Power Exchanges' Simulation Facility by using historical order books (being order books from the operational NTC mechanism). Furthermore, the geographical scope of the FB market coupling simulations is limited to the Nordics + CWE + GB + Baltics.

A4 Simulation results from Nordic power market FBMC model

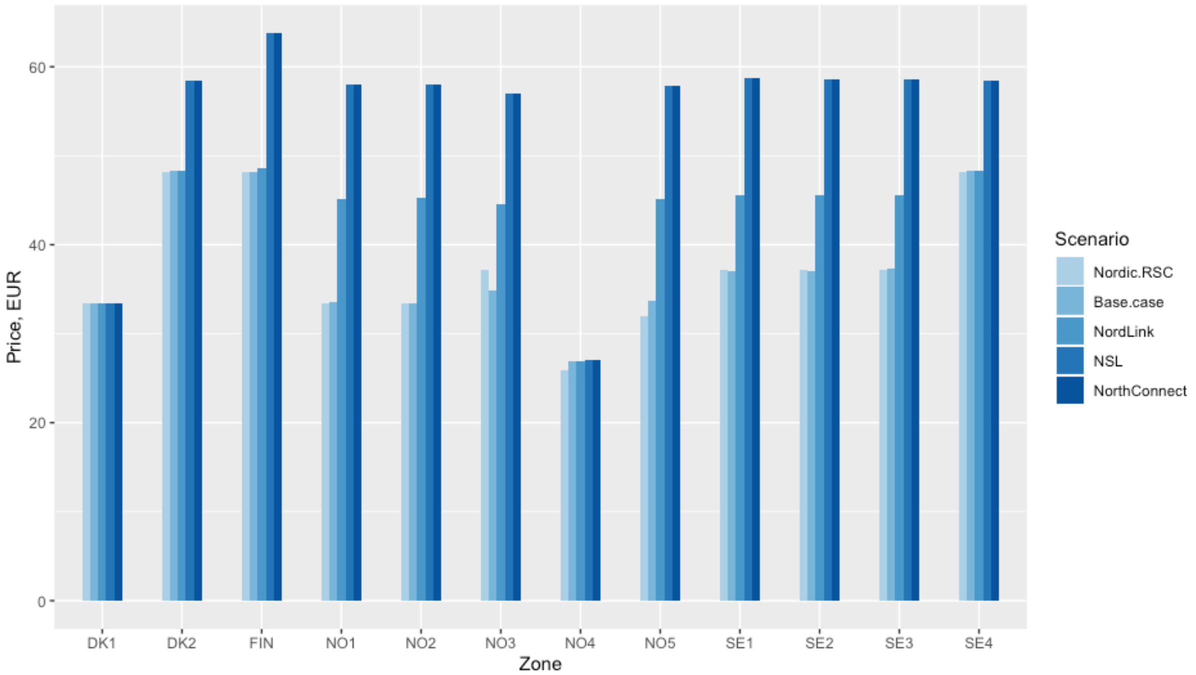

Figure A4.1: Simulation results FB day-ahead prices, constrained hour (08-09). Prices in EUR/MWh.

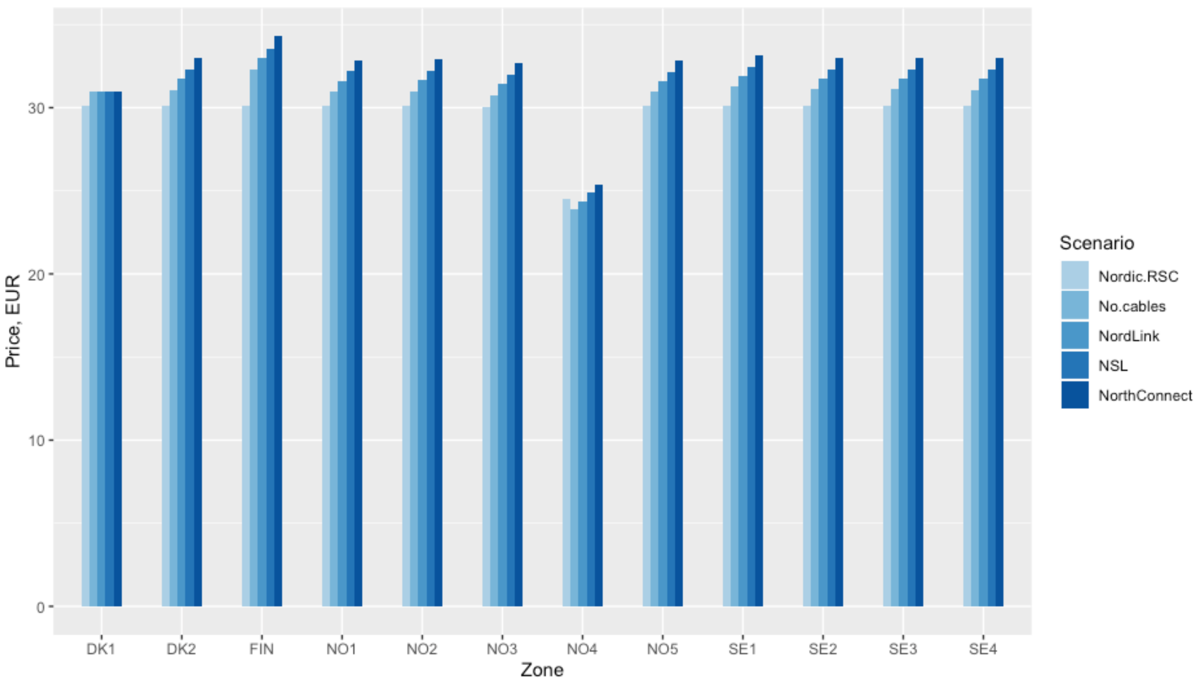

Figure A4.2: Simulation results FB day-ahead prices, constrained hour (04-05). Prices in EUR/MWh.