Renewable and Conventional Energy Sources, Cross-Border Interactions, and Electricity Prices within the Nord Pool Market

Elizabeth Anne Unger

Faculty of Civil and Environmental Engineering
University of Iceland

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Ph.D. Committee
Prof. Gudmundur F. Ulfarsson (Chair)
Prof. Thorolfur G. Matthiasson
Prof. Sigurdur M. Gardarsson

Opponents
Prof. Ronald B. Davies
Prof. Dadi Mar Kristofersson

Faculty of Civil and Environmental Engineering
School of Engineering and Natural Sciences
University of Iceland
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Faculty of Civil and Environmental Engineering
School of Engineering and Natural Sciences
University of Iceland
Hjardarhagi 2-6
IS-107, Reykjavik
Iceland

Telephone: 525 4000

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Abstract

The Lisbon Treaty grants permission to each European Union Member to determine which energy sources shall be used to supply its electricity. While EU members may act independently in this regard, since 1996 when Directive 96/92/EC went into effect, actions have been taken to create a Pan-European electricity market. In this setting, national electricity markets become integrated by operating under a single pricing solution. Recognizing this, there were two main goals in this research. The first aim was to perform a long-term study that estimated how changes in different Nordic countries' generation supply affected its national neighbors' day-ahead electricity prices in the Nord Pool market. The second aim was to estimate the effect of cross-border energy trading and wind generation on price differences between western Denmark and its Nordic trading partners.

The results from the first analysis showed that changes in the energy sources used to supply electricity had varying impacts on the electricity price of different Nordic countries, showing, for example, that average annual prices were affected more when there was a decrease in nuclear production levels rather than an increase. The results from the second analysis showed that planned cross-border energy flow can have a large effect on price differences with the effects also varying across trading partners. It has been shown here that unilateral decisions made by an individual country in an integrated market can have spillover effects, affecting other countries differently. To reduce the negative impacts associated with spillover effects, more harmonization in energy policies between countries is suggested.

Útdráttur

Lisbon samningurinn veitir sérhverju aðildarríki Evrópusambandsins rétt til að ákveða hvaða orkuauðlindir eru notað til að framleiða raforku. Frá 1996 við gildistöku ákvörðunar 96/92/EC hafa verið tekin skref til þess að mynda samevrópskan raforkumarkað, þó svo aðildarríkin hafi haft fullan sjálfsákvörðunarrétt gagnvart stjórnun eigin raforkumarkaðar. Raforkumarkaðir margra aðildarlandanna hafa verið samþættir í þeim tilgangi að verðmyndun verði einsleitari. Sú rannsókn sem hér er kynnt hafði tvö megin markmið. Fyrra markmiðið var að framkvæma langtíma rannsókn sem kannaði áhrif breytinga á framboði rafmagnsframleiðslu tiltekinna Norðurlanda með tilliti til uppruna raforkunnar á næsta-dags raforkuverð í nágrannalöndum á Nord Pool raforkumarkaðnum. Seinna markmiðið var að meta áhrif af millilanda orkuviðskiptum og raforkuframleiðslu með vindorku á mun raforkuverðs á milli vestur Danmerkur og viðskiptasvæða þess svæðis á Norræna markaðinum Nord Pool.

Niðurstöður fyrri greiningarinnar sýndu að breytingar á uppruna raforku höfðu margvísleg áhrif á raforkuverð þjóðanna, meðal annars þannig að ársmeðaltöl raforkuverðs breyttust meira þegar rafmagnsframleiðsla með kjarnorku drógst saman en þegar slík framleiðsla jókst. Niðurstöður seinni greiningarinnar sýndu að áætluð millilandaviðskipti með raforku gátu haft mikil áhrif á verðmun milli landa og að áhrifin voru breytileg eftir löndum. Þessi rannsókn sýnir að einhliða ákvarðanir einstakra landa geta í samtvinnuðum markaði haft áhrif á raforkuverð annarra landa á sama markaði en að áhrifin eru mismunandi. Til að draga úr neikvæðum þáttum slíkra áhrifa er ráðlagt að samræma betur raforkustefnur á milli landa

Dedication

To all the other mothers out there who decided to go back to school

AND

To all the people who ever doubted the mothers' ability to finish!

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1 Introduction

Chapter 1 has been organized into three sections. Section 1.1 begins the dissertation by providing a brief historical description, explaining why the electricity industry changed from being operated by state-owned utilities to a liberalized market where electricity became a commodity traded in different types of electricity markets. Following this brief background information, the motivation and main research objectives of this work are presented. Section 1.3 outlines the organization of the dissertation.

1.1 The Development of Liberalized Electricity Markets

Tired of high inflation and high fuel prices on investments in the electricity industry, the Chilean National Energy Commission (NEC) was conceived in 1978, whose purpose was to eliminate these issues tied to producing electricity (Pollitt, 2004). In taking this step, the NEC established the Chilean 1982 Electricity Act, which unbundled the publicly owned utility through the separation of transmission system operations, generators, and distribution. Overall, the Chilean restructuring model proved to be successful due to the increased labor productivity and service electricity distribution (Joskow, 2003; Pollitt, 2004). It showed other countries that liberalization was an opportunity to eliminate the poor management of assets and increase cost cutting incentives (Biewald et al., 1997). In addition, there was also the potential incentive to advance technology through increased industrial competition, ultimately providing the government and consumers with lower prices (Woo et al., 2003).

As countries began to unbundle the state-owned utilities in the electricity industry, another component of liberalization became the creation of financial markets (Joskow, 1997; Newbery, 1999). The aim was to treat electricity like any other commodity traded in a financial market and allow the different market forces to control and influence prices. However, it became apparent at that time that electricity was unique compared to other commodities. It could not be stored in large quantities, except energy storage in hydro reservoirs, the demand was inelastic, and the physical transmission system requires that there is always a balance between supply and demand (Longstaff and Wang, 2004). Due to these features, electricity prices are characteristically highly volatile (Meeus et al., 2005); because of not being able to hold inventories, i.e., storing electricity, this eliminated the buffering effect that helps reduce sudden large price increases. These factors shaped the way the energy markets were designed.

Additionally, high capital investment characterizes the transmission and distribution segments. That, in combination with non-storability, led to economic incentives for efficiency (Domanico, 2007). These were addressed in Directive 96/92/EC, which created momentum to build a European internal electricity market because it was thought that energy security would increase and prices could stabilize if there were more suppliers operating under one pricing scheme. This directive resulted from political bargaining among the European Commission, the Council of Ministers, and the European Parliament to satisfy certain members' requirements (Domanico, 2007). Unfortunately, according to Domanico (2007) the negotiated Third Party Access, the limited effect of accounting unbundling, and the lack of obligation to create national energy regulators all limited the benefits of a competitive market. These issues were addressed with Directive 2003/54/EC by introducing interconnection to open geographic boundaries and allowing parties to buy and sell energy from whomever and hence increase competition. The effect of this led to a high level of market concentration. For example, in 2006, among the traditional 15 Member States the first three European power generation firms had 60% of the market in 10 different countries (European Commission, 2007).

Competition, among other issues such as security of supply, was addressed by setting a target level for interconnection. Directive 2003/54/EC stated that each nation would have a target of 10% electricity interconnection rate, meaning that there was enough transmission system capacity for it to either export or import 10% of its production/consumption (Directive 2003/54/EC). Policy makers predicted that this 10% level of interconnection would reduce the prices of electricity regionally. To help achieve these targets, the European Commission set up an Expert Group on electricity composed of 15 leading experts on the European energy market and infrastructure. They were from industry organizations, academia and NGOs, as well as the Agency for the Cooperation of Energy Regulators and the European Networks of Transmission System Operators for Electricity and for Gas (European Commission, 2018).

However, regarding what has happened in the Eurozone, it has been speculated that national interests have impeded the development of the pan-European market and there needs to be more focus on creating equal opportunity. One example brought forward by the European Commission was Spain's status. For now, Spain is completely isolated from the rest of the European grid. Spain's detachment from the larger grid makes it more difficult for it to develop a sophisticated, reliable and resilient power grid. France is the only way for Spain to connect to the European grid. Due to Spain's climate and its potential to produce an abundance of cheap renewable energy, this could potentially place French energy companies at a disadvantage by interconnecting the French transmission system with Spain's (European Commission, 2014). Furthermore, while many European countries are still below the 10% target of interconnection, there has been a policy request to increase this target by 5 percentage points so that by 2030 there may be an interconnection target of 15% (COM, 2015).

1.2 Research Objectives

These decisions taken at the international level require more investigations to explore in detail how decision making at the national level can affect neighboring countries against the backdrop of an integrated electricity market. For example, The Lisbon Treaty declares that decisions on the electricity mix and reserve margin are to be made at the national level since each EU member state maintains its right to "determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply" (Article 194, Section 2) (Treaty of Lisbon, 2007). However, without harmonization in policies, it can be assumed that actions taken unilaterally will have spillover effects. This has been recognized by the European Commission, and the EC has therefore called for more harmonization between national policies in this sector (European Commission, 2014).

The motivation of this research was to investigate and quantify how changes at the international level can affect another country's electricity prices operating in the same market. This type of analysis is important and timely, because it can be expected that, as the markets become more integrated, that when one country changes its energy targets, for example, this will have an impact on its neighbor. It can be further hypothesized that the effect will not be the same for every country, where it may be larger or smaller depending on the national electricity generation mix.

Currently, the Icelandic National Power Company, Landsvirkjun, is performing technical and economic feasibility studies on a potential 800-kilometer interconnector, linking Iceland to the United Kingdom (Landsvirkjun, 2017). A task force has been put in place by both governments to continue to investigate key issues.

By focusing on the Nordic countries and exploring the different countries and their relationships in electricity markets, this may provide insight for stakeholders overseeing the Icelandic interconnector. Furthermore, analyses presented here, and ones that are linked to Norway, may provide further insight into these feasibility studies since almost all (97%) of Norway's electricity is generated from hydropower (IEA, 2016d), while hydropower constitutes roughly 72% of electricity produced in Iceland (NEA, 2018).

The overreaching research objective of this dissertation was to evaluate the Nord Pool's wholesale day-ahead market using descriptive tools along with empirical analyses to explore how relationships at the national level and intra-national level affect the day-ahead market.

The main goals are stated as the following three research objectives.

1. **What are the regional level market differences between Nordic bidding areas against the backdrop of market coupling with the Central Western European market?**
   The Nordic market had in November 2011 coupled with the Central Western European market, allowing cross-border energy flow across four market interconnectors (see Chapter 3 for a detailed description). More specifically, the objective was to: 1) Evaluate the market clearing price difference before and after market coupling; 2) describe and compare the utilization of the four interconnectors; and 3) calculate and compare price differences between selected Nordic trading partners tabulated across the trading alternatives for the corresponding Nordic trading area and its Central Western European trading partner.

2. **How will changes in Nordic nations' electricity generation mix affect other countries' electricity prices in the Nordic day-ahead spot market?**
   This second research objective was studied at the national level. For example, this research objective asked: What happens to prices in western Denmark if Sweden reduces it electricity production from nuclear power by one terawatt hour? This allowed an exploration of the level to which unilateral decisions can impact neighboring countries through changes in electricity prices.

3. **How does cross-border energy flow and different wind energy levels effect different pricing outcomes that can occur between Nordic trading partners?** Increased cross-border interconnection can have positive benefits because of increased competition. While increased interconnection may be a viable solution in reducing price volatility, this benefit may be diminished due to increased generation from intermittent renewable energy sources such as wind. Therefore, the third objective of this research was studied at the intra-national level. The contribution of this research was intended to provide a greater understanding of important drivers that affect wholesale electricity prices.

1.3 Organization of Dissertation

The dissertation is organized into five chapters. Chapter 1 contains the introduction, the research objectives, and this outline for the structure of the dissertation. Chapter 2 provides a literature review that covers the necessary background topics related to electricity markets and this research. Chapter 3 is a brief overview of the other Nord Pool markets, including the intra-day market, the regulating market, and the balancing market. In addition to the market and data description, there is also a discussion on the data preparation that was necessary to undertake this research in Chapter 4. The data used to support and answer the research questions came from Nord Pool, along with data from the International Energy Agency. Chapter 4 provides the descriptive analysis that explores the first research objective. Chapter 5 presents the analysis for the second research objective that seeks to estimate the impact of unilateral decisions on prices in other countries that are interconnected in the day-ahead market. The contents of Chapter 5 have been published in a journal article (Unger et al., 2017). Chapter 6 covers the third research objective by more closely examining trading relationships between western Denmark and its trading partners in the day-ahead market by estimating the effect of wind generation and planned cross-border energy flow. This chapter has been published in a peer-reviewed journal (Unger et al., 2018). Chapter 7 provides a closing discussion and overall conclusions, and provides policy recommendations that will serve the benefits of the appropriate stakeholders.

2 Literature Review

The aim of the literature review is to explore earlier studies that have focused on market integration by empirically investigating the benefits and costs related to cross-border energy trading. Building on this, there will also be a review that explores the drivers behind congestion. Congestion is a term that is used to describe when there is not enough transmission capacity that supports the flow of electricity from one area to another forming price differences. This can occur either between different areas operating in the same nation or across international borders. A review of congestion management is important because in the day-ahead spot market and the intra-day market there are scheduled trades of energy that flow between different sets of neighboring areas to level price differences.

2.1 Market Integration

To what degree market integration has been reached has become a critical question, and in comparison to other topics studied in electricity markets such as forecasting prices (see e.g., Cuaresma et al., 2004; Jónsson et al., 2013; Maciejowska et al., 2016) there is still not a substantial amount of research that evaluates the impact of large-scale energy market coupling (Newbery et al., 2013). Zachmann (2008) analyzed electricity market prices from eleven European countries that covered the years 2002 to 2006. The aim of Zachman's (2008) study was to identify the current level of integration by using a principal component analysis for normalized data. Zachman (2008) found that European electricity market integration was not a universal process, and if it did occur, it was on a pairwise basis only, providing evidence that convergence was predominately driven by cross-border market integration. De Menezes and Houllier (2016) extended Zachman's (2008) analysis by applying a time-varying fractional cointegration analysis to daily spot prices from February 2000 to March 2013 for nine European electricity spot markets. De Menezes and Houllier (2016) argued that earlier studies that used unit root tests such as the augmented Dickey-Fuller test, which are typically used to test market integration, were inadequate for spot prices because spot prices are fractionally integrated and mean-reverting time series. However, this argument has been countered by Gelabert et al. (2011) who successfully used the augmented Dickey-Fuller test in an ex-post analysis on daily day-ahead Spanish prices. In addition, as changes occur in the EU electrical system, the spot price behavior will reflect this in their behavior. While enhancing the method to assess integration, the results of de Menezes and Houllier (2016) were like Zachman's (2008) in that their results showed that areas that are geographically close or well-connected will have longer periods of price convergence, but overall, the analyzed electricity spot prices were not increasingly converging. Furthermore, Germany's closure of its nuclear plants negatively affected market integration, highlighting the need for more studies that considered the electricity supply mix (de Menezes and Houllier, 2015).

The studies discussed above are those that evaluate the status of market integration by studying price differences from different exchanges and countries. Another topic has been to estimate the welfare effect of introducing cross-border energy trading between two countries. The volume effect and strategic effect of the interconnection will determine the welfare gains and losses in countries (Pellini, 2012). Hobbs et al. (2005) performed one of the earlier studies using simulated data to compare potential market outcomes for the Dutch (APX) and Belgian (BelPex) power exchanges with and without market coupling. Hobbs et al. (2005) found that there was a potential improvement to social surplus delivered from the complementary generation mixes and load profiles of the two nations. However, Hobbs et al. (2005) also found that total benefits could be reduced because market coupling could potentially encourage oligopolistic behavior from the largest producer due to the perceived diminishment of regulatory intervention, suggesting that the benefits of large-scale market coupling may not be as large as expected. This finding was further supported by Gebhardt and Hoffler (2013) who found that well informed traders do not engage in cross-border energy trading, thus impeding the benefits stemming from increased competition.

While Hobbs' et al. (2005) examined the Dutch and Belgian power exchanges, Lise et al. (2008) tested the vulnerability of a pan-European market in which 20 European countries are connected and the supply was hypothetically disrupted by extreme weather. Lise et al. (2008) also evaluated the impact of transmission capacity on prices. Lise et al. (2008) found that the large differences in power stations and the generation mixture across national borders created large spreads in prices. Another finding by Lise et al. (2008) was that in countries with few generators that this would potentially induce large price differences, since these companies were able to exercise market power due to owning a large percentage of the market, and secondly, the market was highly accessible to these firms (Lise et al., 2008).

Shortly after Hobbs et al. (2005) published their research, in November 2006, the Belgian (BelPex), Dutch (APX), and French (Powernext) power exchanges were coupled. The integration of these three electricity markets now allowed researchers to analyze these markets using real data. Küpper et al. (2009) built on Hobbs et al.'s (2005) work, except that Küpper et al. (2009) explored price differentials between the three markets to test for the presence of competition using real data. Küpper et al. (2009) found that a majority of the time (60%) prices were equal, but concluded that it was not sufficient to identify if the markets were concentrated. While Küpper et al. (2009) discussed the important role of increased transmission capacity in decreasing the risk of market power, Küpper et al. (2009) stated that it is more beneficial to increase transmission capacity in areas where it is small or nonexistent, in areas where the regions have heterogeneous generation mixes and demand profiles, and when the other region has a higher level of competition. Others like Borenstein et al. (1997), Shrestha and Fonseka (2004), and de la Torre et al. (2008) have also come to similar conclusions, that increasing transmission capacity decreases the opportunities for market abuse while improving market conditions for competition.

Valeri (2009) investigated the impact of a market interconnector between Ireland and Great Britain to social welfare and competition. Valeri (2009) used simulated data like Hobbs et al. (2005) to find that market coupling can lead to an increase in social welfare, although the addition to social welfare occurs at a decreasing rate. Valeri (2009) explained that while market coupling increases competition in Ireland and both sides gain from the differences in technology, the rate of gains is potentially reduced because the return to the investors from the interconnector is less than the amount required to provide the optimal amount of transmission capacity. This makes it unlikely that private investors will pay for the optimal amount of interconnection since the total social benefit is much larger than their returns.

Influenced by the large penetrations of wind generation in Ireland, Denny et al. (2010) performed simulations that analyzed the impact of increased interconnection between Ireland and Great Britain. While the results showed that there would be a reduction in prices and more stabilization, in terms of carbon emission the net change was zero. This occurred because the production of emissions shifted from the relatively more expensive system to the cheaper system, in this case, from Ireland to Great Britain. Furthermore, if there were more increased interconnection, it would not be used to export excess wind generation from the Irish system. According to Denny et al. (2010) this was because wind forecasts are included in the unit commitment, so wind curtailment would already be at a low level for the wind penetration. Finally, Denny et al. (2010) concluded that increased interconnection dramatically improved the security of the system with the number of hours when load and reserve constraints were breached.

Evaluating market coupling in a different region, Zani et al. (2012) explored what would happen to Italian electricity imports and prices if Germany, Slovenia, Austria, Switzerland, France, and Italy became integrated. Zani's et al. (2012) results were positive by finding that market coupling could potentially lead to a reduction in Italian net imports because then there would be a more optimized use of the available transmission capacity. Zani et al. (2012) discovered that the increase in efficiency also led to a reduction in adverse flow, which happens when electricity flows from a high-priced area to a low-priced area. The gains generated would then allow Italian generators to not only increase the amount of generation but also the price at which it was sold, making market coupling a viable option for Italy (Zani et al., 2012). One component of Zani's et al. (2012) research was that the estimated benefits were derived under the assumption that the cross-border energy flow between the countries operated under explicit auctioning. The term explicit auctioning means that the allowable cross-border transmission capacity is not used in the market clearing process. The opposite of explicit auctioning is implicit auctioning. This form of auctioning, which is currently being implemented across Europe, has been shown to increase transparency and deter negative market behavior to a certain level (Weber et al., 2010). Implicit auctioning is also a component to congestion management.

2.2 Congestion Management

At certain periods there may not be enough available transmission capacity to meet the market's needs. A consequence of this physical constraint is that the volume required to meet the market's demand becomes bottlenecked by the transmission capacity, impeding the flow of low cost electricity to a specific area (Singh et al., 1998). This is known as congestion, and dealing with congestion has been a longstanding issue in electricity markets where there are different approaches used to mitigate the issue.

An earlier approach was the uniform wholesale pricing scheme. This approach did not consider the location of the demand and generation, producing one uniform price for the entire system. Essentially, a uniform price is an unconstrained price since it does not incorporate the physical constraints tied to the transmission system in the price calculation. To account for the transmission expenses, these are covered by containing a fixed fee for network access and variable demand charge. The drawback of this approach is that there is no price signal for when transmission capacity is scarce, and it fails to identify locations that require extensions (Krause, 2005).

Consequently, this unconstrained price does not send accurate price signals and can hamper investment decisions. To correct this issue, there are two general pricing methods that are implemented across electricity markets, locational marginal pricing (LCM) or zonal pricing. Locational marginal pricing is also known as nodal pricing. Under the zonal pricing, zones are geographical areas defined by the transmission system operators that exist within a larger grid, which may be defined either ex-ante and have fixed zones, such as the Nordic market, or post-ante and have zones defined according to the congestion situation. The terms zones and pricing areas in this context may be used interchangeably to avoid redundancy in the text, which has been done here. In the presence of congestion, the zones will have different prices. Mentioned earlier was the term implicit auctioning. To either reduce these price differences or eliminate them between the zones, the transmission system operators decide on an available amount of electricity that may be exported from the area with the surplus supply, (i.e., an area with a lower demand) to the zone whose demand is higher. The effect is to reduce price differences between the zones and decrease the risk of arbitrage.

Nodal pricing is an extension of the zonal approach in that a price is calculated at each node using welfare analysis. A node is a physical bus or a collection of buses within a transmission network. An aggregation of nodes is referred to as a load zone. Nodal pricing is the marginal cost of supplying, at least cost, the next increment of one megawatt power at a specific node on the transmission. Like zonal pricing, the price is calculated by using both bids and offers given for that specific hour, except zonal prices are the load weighted average of the prices of all the nodes in a zone. Unlike the zonal price, which is adjusted to account for transmission constraints and losses, these components are already embedded in each nodal price. In addition, the generators are dispatched by the transmission system operator not only in descending order of bids (or ascending orders of offers), but in accordance with the required security of the system, while also including the losses and constraints of the grid (Leuthold et al., 2008). Therefore, it has been claimed that markets that operate under a nodal pricing system produce spot prices that are security-constrained, bid-based, and economically dispatched according to correct price signals, making nodal pricing a truer reflection of the actual situation in the grid (Hogan, 2003).

Zonal and nodal pricing schemes have been assessed under different scenarios. Leuthold et al. (2008) considered the potential impact of increased electrical wind generation from offshore wind farms on Germany's existing grid. Leuthold et al. (2008) calculated the overall changes to social welfare under different scenarios using either a nodal or zonal pricing approach and found that nodal pricing was economically superior over zonal pricing. Neuhoff et al. (2013) also compared two market designs: an optimized approach of implicit auction of transmission capacity between nationally defined price zones; and a nodal pricing approach under varying penetrations of wind power. Neuhoff et al.'s (2013) results showed that most transmission constraints occurred within the country rather than on lines between countries. In turn, this created incentives for transmission system operators to limit the flow that was meant to leave the country to deal with internal congestion. This happened in California where the initial design divided California's grid into three zones with only two available paths in times of constraints (Price, 2007). It was found that most congestion occurred inside the zones and accounted for more than 200 million dollars of yearly intra-zonal congestion costs (Price, 2007). Due to the variability of wind in different locations, Neuhoff et al.'s (2013) nodal pricing simulations illustrated that the congestion and price patterns varied considerably between wind scenarios, suggesting that defining price zones within countries were not suitable to address internal congestion, as the zones would either have to vary depending on the system conditions (impractical for contracting purposes) or be small (and thus be essentially equivalent to nodal pricing). Oggioni and Smeers (2013) further supported Neuhoff et al.'s (2013) findings by also investigating the combination of wind generation combined with the zonal congestion scheme. They showed that this combination induces more spatial arbitrage, which introduces more risk of price gouging from utilities that control transmission services. While EU regulation 1227/2011 (REMIT) was established to survey and prevent market manipulation, the surveillance methods do not occur at the hourly level which is where and when electricity generators may engage in negative market behavior (Makkonen et al., 2013). This comes at a time when Europe seeks to increase renewable electricity generation, while simultaneously dealing with an insufficient network capacity and the congestion that will result from the new flow patterns.

Despite these advantages, Alaywan and Wu (2004) argue that when compared to nodal pricing, zonal pricing is a less complex approach, which increases transparency for market participants. The zonal pricing scheme is applied in the Nordic market and Juselius and Stenbacka (2011) applied cointegration analysis to daily averages of Nord Pool day ahead spot prices between 2001 and 2007 to evaluate market performance. The results from their empirical analysis showed that the different zones were fragmented, and market performance could be improved by delineating the zones and reconstructing them. Furthermore, the areas should ignore national boundaries such as they are designed now and should be redefined such that Finland, Sweden, and Norway 3 belong to the same relevant market, for example.

In 2010, the Nordic market set a target where the area prices would equal the unconstrained system price 65% of the time or congestion would be present 35% of the time. To test the level of congestion in the Nordic market, Makkonen et al. (2013) evaluated the number of hours in 2012 when congestion was present. Makkonen et al. (2013) showed this target was never reached. The results showed that the day-ahead market only had equal prices 19% of the time, almost half of the target of 65%. Furthermore, Makkonen et al.'s (2013) assessment came at a time when the Nordic market had coupled with the Central Western European market in November 2011, suggesting that the expected benefits of increased price stability due to large-scale market coupling might not be as large as planned.

One factor that has been shown to increase congestion and reduce the stability of the transmission system is wind, due to the intermittent nature of wind energy and its ability to bid into the market at almost zero prices (Hiroux and Saguan, 2010). Leuthold et al. (2008) examined the potential effect of extending Germany's grid to include off-shore wind farms under a zonal and nodal pricing scheme. While the authors found the nodal pricing scheme to be more optimal, they also found that in times of high input from offshore farms, this could not only affect Germany by increased risk of congestion, but also the neighboring grids. To promote higher levels of wind integration without requiring wind curtailment, Matevosyan et al. (2009) showed the positive benefit of there being more coordination between hydropower plants and wind power plants, while also ensuring that hydropower is given priority in transmission capacity in the day-ahead market and regulating market for

Sweden and Norway. Matevosyan et al. (2009) also showed that, despite the price a wind utility might pay to a hydropower plant to avoid curtailment, more income was earned due to a 75% decrease in wind curtailments.

Unlike Norway, where hydropower accounts for roughly 97% of the electricity generated, less than 1% of electricity is generated from hydropower in Denmark, yet Denmark has successfully increased its wind capacity so that in 2016 roughly half of the electricity production was from wind energy (Danish Energy Agency, 2017). There are several factors that have contributed to this, but one reason has been the coordination between combined heat and power plants and wind power plants for automatic generation control (Basit et al., 2017). Automatic generation control is maintained in real time and regulating power bids which are activated manually in the control room. While hydropower may store its energy in reservoirs, combined heat and power plants may store energy as steam. To ensure the stability of the Danish system with high levels of wind integration, Basit et al. (2017) developed an algorithm that developed strategy between these two types of power plants. While Basit et al.'s, 2017 study was related to design, there are studies that evaluate the impact that arise from increased wind generation. Another factor that has facilitated the growth of the wind industry in Denmark has been the interconnection to Norway, where Norway may dispatch hydropower in peak demand, which is typically less than the marginal cost of a thermal generation plant.

To summarize, the key points made in this literature review is that increased interconnection can reduce price volatility, although there are other factors that may work against this. Nodal pricing may be more optimal than a zonal pricing scheme to handle congestion, but since zonal pricing requires less computational power, it increases the transparency for the market players, and for now, this method is implemented across many European countries. Intermittent renewable energy sources are vital in combatting climate change, but due to their ability to bid in the markets with almost zero prices, this can induce congestion. Finally, unilateral decisions taken at the national level can have a spillover effect on its neighbors in terms of electricity prices in an integrated market.

3 Description of the Nordic Electricity Markets

The research presented in this dissertation focuses only on the day-ahead market. However, there are four markets that operate under Nord Pool. Each market is described briefly in this chapter.

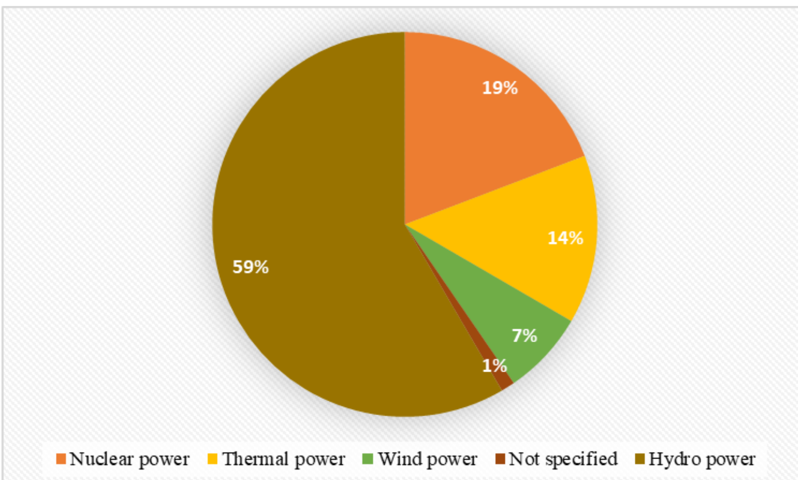
3.1 Nord Pool Transmission System Operators

Nord Pool is currently owned by seven transmission system operators (TSO), of which four are Nordic TSOs and three are Baltic TSOs (Nord Pool, 2018a). Each TSO is state owned and commissioned by its national government to conduct specified projects related to energy targets and security of supply. The following TSOs that operate in Nord Pool are:

- Nordic Transmission System Operators
    - Statnett SF operates 150 Norwegian power stations and oversees the distribution of supply from three regional control centers (Statnett SF, 2017)
    - Svenska kraftnät is the Swedish TSO and it also conducts and supports projects related to the national electricity grid, dam safety, other potential risks in the power system (Svenska kraftnät, 2017a)
    - Fingrid Oyj is the Finnish enterprise responsible for ensuring the functioning of the high-voltage grid, transmit electricity from generators to distribution network companies, and operate the cross-border electricity trading (Fingrid, 2017).
    - Energinet.dk is the Danish TSO and as the other TSOs is responsible for overseeing and constructing the high-voltage grid. In addition, Energinet.dk owns, operates, and constructs gas pipelines for distribution (Energinet.dk, 2017).
- Baltic Transmission System Operators
    - Elering is the Estonian TSO and was founded on January 27, 2010. The Republic of Estonia hold all shares whose shareholder’s rights are being executed by the Ministry of Economic and Affairs and Communication. Currently, Elering is working towards desynchronizing itself from the Unified Energy System of Russia and integrating itself into the European grid (Elering, 2017).
    - Litgrid is the Lithuanian TSO and is currently working to synchronize its grid, namely through NordBalt (Lithuania-Sweden) and LitPol (Lithuania-Poland), high-voltage cross-border links (Litgrid, 2017)
    - Augstspriedguma tikla (AST) was founded in September 2005 and is responsible for overseeing operations related to high-voltage lines in Latvia (Augstspriedguma tikla, 2017).

3.2 Electricity Generation Mix for Nordic and Baltic Countries

Each TSO is responsible for ensuring the security of the transmission system. Each energy source has unique features, which control the way electricity is dispatched. For example, nuclear power plants tend to be operated at a constant output level, while hydropower plants have more flexibility to respond more rapidly to fluctuations in demand (Talukdak and Wu, 1981). Figure 1 shows the total percentage of production from each energy source for the entire Nordic and Baltic regions on November 3, 2017. More than half of the electricity produced was from hydropower (59%), while nuclear was about 19% and thermal power about 14%, with wind at 7%. These percentages may vary due to seasonal changes.



(Source: Svenska kraftnät, 2017b)

Figure 1 The percentage of total production from different energy sources for Nordic and Baltic regions on November 3, 2017.

When disaggregating the values presented in Figure 1 by country and energy source, it is possible to see the diversification of the generation mix at the national level. Table 1 shows that Norway produced two times more power than Sweden using hydropower, while Sweden produced four times more power from nuclear energy than Norway. Table 1 also shows that on this day roughly 10% of the power produced was from wind energy for Denmark, while this corresponding figure was 3 percentage points higher for Finland.

Table 1 Total power production in megawatts categorized by energy source and country on November 3, 2017.

	Sweden	Denmark	Norway	Finland	Estonia	Latvia	Lithuania	Total
Production	22,693	3,584	21,311	8,215	1,146	1,261	495	58,705
Nuclear power	8,491	-	-	2,782	-	-	-	11,273
Thermal power	1,045	3,208	298	2,360	1,076	189	147	8,323
Wind power	2,154	376	369	1,124	70	8	38	4,139
Not specified	439	-	-	66	-	178	-	683
Hydro-power	10,565	-	20,645	1,883	-	886	311	34,290
Total consumption	19,334	5,182	17,330	10,502	1,198	1,084	1,707	56,337

(Source: Svenska kraftnät, 2017b)

Identifying this level of diversity in terms of different energy sources used for electricity generation provides a background of understanding that shows why electricity prices can vary. Some studies have attempted to evaluate these technologies on cost alone across a wide cross-section of countries, but the costs can range greatly due to regional and national differences such as additional infrastructure, the availability of fuel supply, and the ability to run on baseload (Sims et al., 2003). In addition, there are also national policies that can influence electricity prices and the development of renewable electricity such as the policy design in Denmark and Germany using feed-in-tariffs (Lipp, 2007). Essentially, electricity prices are highly dependent on location.

3.3 The Nordic Day-Ahead and Intra-Day Market

Nord Pool's day-ahead market, also known as Elspot, and the intra-day market, termed Elbas, are both electricity markets where market parties are free to buy or sell electrical energy from/to whomever they wish. The key difference between these two markets is that the Elspot price is based on bids and offers submitted at closing noon central European time (CET) and at least 24 hours prior to the hour of delivery (Nord Pool, 2017a). To execute these transactions, market parties enter into contractual purchase and sales relationships. Faced with the physical constraints of the transmission systems, market parties accept that power produced and put onto the grid cannot be stored and must be consumed as soon as it is generated. Therefore, generation companies and suppliers must produce a day-ahead schedule that states the amount of generated power that will be equal to their intended sale to customers or other power companies.

Earlier, implicit auctioning and zonal price schemes were defined. These two platforms are implemented in Elspot. When the bids and offers are submitted, so is the information related to which geographical zone the bids and offers originated from. In the case when there is a transmission capacity constraint that impedes the flow of electricity, price differences will arise. To level these price differences and to reduce the risk of arbitrage, the TSOs will decide on an allowable amount of flow of electricity to be exported from the area with a surplus of supply to an area where there is a deficit, resulting in either there being no difference in price or the difference is not as large.

A unique feature of either spot or balancing prices is that they may be zero or negative. It was legislation that went into effect on November 30, 2009 that introduced negative prices to Nord Pool's day-ahead market. The objective of the legislation was to promote renewable energy by creating a market force that would regulate electricity production in relation to wind power (ICIS, 2009). On December 20, 2009, electricity spot prices plummeted to -7.40 €/MWh due to very low demand and high wind generation (ICIS, 2009). Negative prices mean that the destruction of the electricity has more value than its creation, making it a waste product that is dumped back onto the market (Sewalt and De Jong, 2003). Therefore, producers must pay to dispose of the electricity they produce. Zero prices also indicate that production has surpassed consumption. Sewalt and De Jong (2003) produce an example, which illustrates why negative prices occur and why generators accept them. Different types of generating facilities are each faced with various technical constraints. A combined-cycle generation plant's primary product is heat, while electricity is a co-product. It is hardly an option to reduce the must-run output, and shutting down involves high costs (Sewalt and De Jong, 2003). Generators accept negative prices because, even though it is a loss, the opportunity costs of shutting down are much higher, although this only holds if the negative prices are short-lived.

Price differences across zones indicate that more investment is required for the transmission system to support the flow of electricity. Using the price difference and the volume of energy flow from the surplus zone to the deficit zone, congestion rent is calculated, which is an ownerless income. The formula used to calculate congestion rent is calculated as the product of the congestion price and the line flow connecting the zones (Nord Pool, 2017b),

$$(P_j - P_i) * F_{ij} \tag{1}$$

where P_j is the higher price in zone j and P_i is the lower priced zone, and F_{ij} is the energy flow that goes from the low-priced area to the high-priced area. How the income is distributed is determined in separate agreements between the TSOs, but often the income is shared between the two parties involved, or it is divided according to the percentages related to one party's level of involvement in projects aimed at improving the transmission system (Nord Pool, 2017b). It may occur that the direction of flow does not correctly follow the price, in that the electricity flows from the deficit zone to the surplus zone. This is termed adverse flow.

As Nord Pool has developed over the years, the number of zones/areas has increased. Denmark has always constituted two areas, western Denmark and eastern Denmark. Finland has always been one zone, and in April 2009 Norway was divided into three zones (see Table 2). By September 2011, Norway was divided into five zones, and on November 1, 2011 Sweden went from one zone to being four.

Table 2 Geographical changes to zones in Nordic region from April 2009 to Nov 2011.

Change	Valid	Zone and city reference
Sweden becomes four areas	Nov 1, 2011	SE1 – Lulea SE2 – Sundsvall SE3 – Stockholm SE4 - Malmo
Norway becomes five areas	Sept 5, 2011	NO1 – Oslo NO2 – Kristiansand NO3 – Molde, Trondheim NO4 – Tromso NO5 - Bergen
Norway becomes four areas	Feb 7,2010	NO1 – Oslo NO2 – Bergen, Kristiansand NO3 – Molde, Trondheim NO4 – Tromso
Norway becomes three areas	Jan 10, 2010	NO1 – Oslo, Bergen, Kristiansand NO2 – Molde, Trondheim NO3 – Tromso

To show these zones on a map, Figure 2 is presented. In all, there are fifteen pricing zones. Each zone will have its own set of trading partners, i.e., those areas where electricity is either imported or exported to level price differences for the hour. In all, there are 22 sets of trading partners, including intra-national trade partners and cross-border partners. The complete list is shown in Appendix A. To present an example here, western Denmark has been selected. Western Denmark's Nord Pool trading partners are eastern Denmark (DK2), Stockholm, Sweden (SE3), and southern Norway (NO2).

(Source: Nord Pool, 2017a)

Figure 2 The Nord Pool geographical zones.

Also notice in Figure 2 that there are abbreviations for each geographical zone. These abbreviations have been created by Nord Pool and are used throughout this dissertation and are fully listed in Table 3.

Table 3 The abbreviations for geographical zones defined by Nord Pool.

DK1	West Denmark	NO1	Eastern Norway	SE1	Swedish area 1	EE	Estonia
DK2	East Denmark	NO2	Southern Norway	SE2	Swedish area 2	LV	Latvia
FI	Finland	NO3	Mid-Part Norway	SE3	Swedish area 3	LT	Lithuania
		NO4	Mid-Part Norway	SE4	Swedish area 4		
		NO5	Western Norway				

A decisive step towards realizing a Pan-European electricity market occurred on January 12th, 2011 when the NorNed Cable successfully linked the Nordic and Central Western European markets (Nord Pool, 2017d). The energy that flows across these interconnectors is reflected in the price formation as buying and selling volumes for the respective Nordic bidding area (Nord Pool, 2017e). Both western (DK1) and eastern (DK2) Denmark each have a separate interconnector that connects each of them to Germany (DE), although the available capacity between western Denmark and Germany exceeds that of the other three interconnectors by almost a factor of three (1,780 MW). The Kontek interconnector is a 110-mile (170 kilometers) underground and submarine cable with a maximum available capacity of 600 megawatts (MW), which connects Bjæverskov, eastern Denmark to Bentwisch, Germany. The Baltic interconnector was installed in 1994 with a transmission capacity of 600 MW, the same capacity as the Kontek interconnector. Of these four interconnectors, the NorNed is the newest and longest underwater cable that connects southern Norway (NO2) to the Netherlands (NL). Its total length is roughly 360 miles (580 kilometers) and it has a transmission capacity of 700 MW (Table 4). As shown in Table 4, western Denmark (DK1) has four trading partners.

Table 4 Maximum transmission capacities in megawatts for Nordic and Central Western European high voltage interconnectors.

Jutland -Germany		Kontek		NorNed		Baltic	
DK1->DE	DE->DK1	DK2->DE	DE->DK2	NO2->NL	NL->NO2	SE4->DE	DE->SE4
1,780	1,540	585	600	700	700	615	600

Delivering electricity to consumers requires a balance between the transmission system’s load and demand. Therefore, in the past it was pertinent to accurately forecast a system’s load while relying on the generators to dispatch enough supply. As the share of renewable energy sources (RES) has increased in generating electricity, their intermittent nature requires more sophisticated methods for forecasting (Wang et al., 2011). Furthermore, there may be policies in place that increase renewable energy source development through the government providing funds to RES generators so that they can compete competitively with other type of generators, along with priority given to RES generators in terms of transmitting electricity onto the grid.

One feature of the day-ahead market is ramping. Ramping refers to the change in power flow from one time-unit to another (Nord Pool, 2018b). Ramping, as it is implemented in the Nordic market, occurs when there is one area connected to another area via a high voltage direct current cable interconnector (Nord Pool, 2018b). The function of ramping is to create flexibility within the market by placing priority to any electricity generated from RES while also working around the physical constraints of the transmission system.

The mechanics of an HVDC cable are different than that of a high voltage alternating current (HVAC). Mainly, energy can only flow in one direction during a certain period on an HVDC cable, whereas on an HVAC cable, the energy can change directions periodically. In addition, the TSOs are in charge of any energy flow that occurs over the HVDC interconnectors. For this reason, along with the higher levels of integration for renewable energy sources, ramping creates a platform for other conventional generators to either increase or decrease production. Essentially, they are being paid for their "flexibility" (Meibom, 2007).

Ramping may be detected in the data by comparing the high and low prices between two areas and direction of flow. When there is no ramping, the spot price differences should reflect the theory of electricity flowing from a low-priced area to a high-priced one, or there being no exchange since prices are equal. When ramping is implemented, the frequencies between the price differences and flow patterns will not match.

Elbas, the intra-day market, also has a schedule traded energy flow. To handle contingent events such as a plant shutting down or the wind not blowing, for example, there is the intra-day market. Elbas is a continuous market that operates one hour prior to the hour of delivery. Unlike Elspot, where there is one hourly market clearing price calculated by using the aggregate supply and demand curves, there are two prices for Elbas. Prices are based on a first-come, first-serve principle, where the best price comes first. There is the highest buy price and the lowest sell price (Nord Pool, 2017c).

The most volume is traded on the day-ahead market. This point is illustrated in Figure 3, where one day, November 3, 2017, and Norway (NO2) exporting electricity to western Denmark (DK1) has been selected. The orange represents the total volume exported by Norway to western Denmark for the day-ahead market and the blue represents the volume exported to handle the imbalances in Elbas. The image shows that only in the later hours was there some volume exported for Elbas.

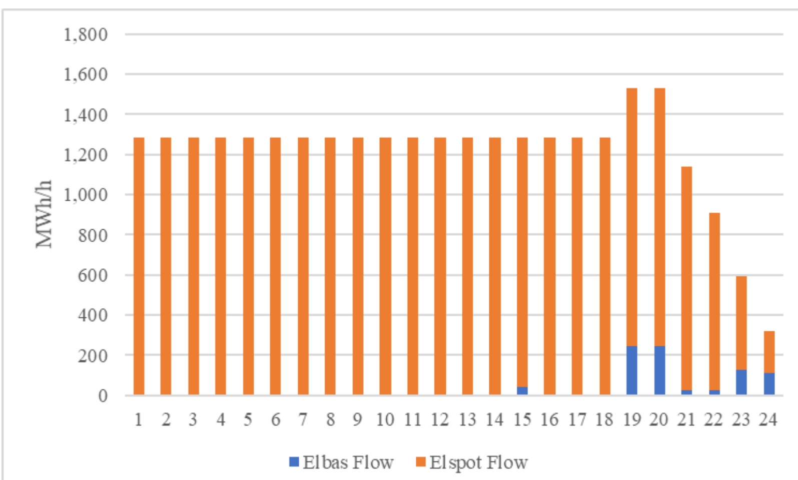


Figure 3 Hourly traded volume on November 3, 2017 from Norway (NO2) to western Denmark (DK2) on the day-ahead market (Elspot) and intra-day market (Elbas).

3.4 The Regulating Market

Understanding the operational aspects of the different types of power plants is critical in integrating intermittent renewable energy sources into the generation mix. As the penetration of these types of sources increases, so does the risk of increasing forecasting error. As for the Elbas market that operates continuously with market closure occurring two hours before the hour of delivery, there is the regulating market, whose price settlement occurs 15 minutes before the actual delivery (Nord Pool, 2017e). Therefore, as there becomes higher penetration of intermittent sources, these markets will become more important to handle the system balances.

It is the transmission system operator's (TSO) responsibility to handle changes that may disrupt the stability of the transmission system (Nord Pool, 2017e), while also ensuring payment is received from or paid to the market participants.

In the regulating market, the TSO buys or sells power from or to the trading parties on the basis for upward and downward regulation submitted to the TSO by the buyers and sellers involved. The market participants of the regulating market are referred to as the Balance Responsible Party (BRP), which may be separate and external sources (Neupane et al., 2015). A key feature of a Balance Responsible Party member is that the party must have the flexibility to either buy or supply energy within fifteen minutes of being given notice (Neupane et al., 2015). Therefore, once the bids and offers have been submitted two hours before the hour of operation, and the market will be cleared only if there is a system imbalance, the price settlement will occur 15 minutes before the actual delivery (Neupane et al., 2015).

The regulating market may be in one of three states. When there is not enough supply to meet demand, the TSO must ensure that one or more BRPs will deliver more electricity to the grid or decrease the demand by an amount equivalent to the difference. This is known as procuring "up regulation". When supply exceeds consumption, the TSO is procuring "down regulation," and the BRP must sell down-regulating power at a down regulating power price to maintain the energy balance in the market. The down regulating power is sold to the reserve energy market or the demand is increased by an amount equivalent to the difference (Neupane et al., 2015). Thus, there are two types of imbalance prices, upward regulating prices and downward regulating prices. The final state is that no form of regulation is required due to the transmission system already being in balance.

Regulating prices are formed by the merit order (see Figure 4). If there is a need for upward regulation, the up-regulation orders with the lowest prices are activated until the required level of power is acquired. The last upward regulated megawatt (MW) sets the up-regulation price. The orders with prices below the up-regulation price have a profit which is equal to the difference between the final regulation price and the market area clearing price (Nord Pool, 2017e). Down regulating prices are determined using the same approach, but these prices are below the market area clearing price.

In practice, either prices or regulating volumes could be used to determine the state of the regulating system. However, Jaehnert et al. (2009) suggest that it is a better approach to use regulating volumes to determine the state of the system over prices. This is because even when regulation volumes are zero, which should indicate that the difference between the spot price and the regulating price should be zero, there may be slight price differences.

These small differences are due to the impact of regulation in other market areas (Jaehnert et al., 2009).

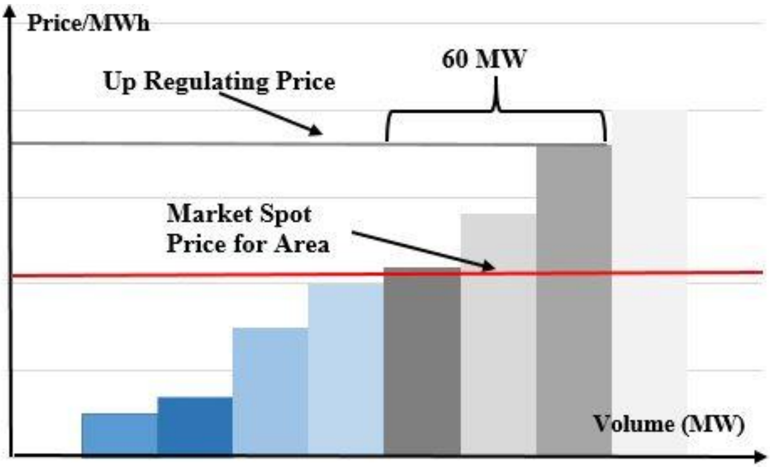


Figure 4 Illustration of merit-order method used to determine upward and downward regulation prices in Nordic Regulating market.

Regulation rules require that the TSO calculates the imbalance price to be paid by the BRP to the TSO or received by the BRP from the TSO (ENTSO-E, 2013). Depending on the state of the system, the TSO must calculate the imbalance price to be paid by the BRP to the TSO or received by the BRP from the TSO (ENTSO-E, 2013). To calculate the total amount or value that the TSO must either pay or receive, the imbalance value is calculated using the premium (EUR/MWh), which is the difference between the area price and the regulating value multiplied by the total regulating volume (MWh).

Thus, “the payments and charges are based on underlying balancing market prices, which in turn provide market participants that bear balancing responsibility with the incentive to have their demand and supply in balance so that overall deviations of the system are minimized. Under this payment scheme, this process should be a 'zero-sum' game where the transmission system operator has no financial interest and bears no financial risk” (ENTSO-E, 2015). The BRP may eventually settle the regulating loss with the energy suppliers that did not fulfill their commitment, or the cost is transferred to the customers (Neupane et al., 2015).

While there is an abundance of literature that focuses on day-ahead spot markets for electricity, there is less when the focus shifts to the regulating market. One of the earliest studies was produced by Skytte (1999) who used regulating volumes to predict regulating prices in the Nordic market. A key finding of Skytte’s (1999) was that the amount of upward regulation had a stronger effect on the up-regulating price than for down-regulating volumes on down-regulating prices (Skytte, 1999). Because of this asymmetric cost, Skytte (1999) proposed that participants in the day-ahead market may behave more aggressively with their bidding strategies, since one must pay a premium for readiness in addition to the spot price. Later, Olsson and Soder (2008) created a model, different from that of Skytte

(1999), that would forecast regulating prices. They used a combined seasonal auto regressive moving average and discrete Markov processes to model prices.

Fabri et al. (2005) explored the energy costs in the market for wind generators associated with wind prediction errors. They analyzed three study cases: a single wind farm, an ensemble of 15 wind farms, and the simulated total production of peninsular Spain. Error prediction energy costs were presented as a percentage of total generator energy incomes. Fabri et al. (2005) showed that the error prediction costs can reach as much as 10% of the total wind production incomes from selling energy. However, by aggregating energy production from wind plants spread over large areas, this will decrease prediction costs by decreasing the time horizon making the prediction closer to the real-time market, improving the accuracy of the wind production forecast model

Jaehnert et al. (2009) expanded on Skytte's (1999) research by introducing a newer econometric model that instead of predicting regulating prices, predicted the difference between the spot price and the regulating price, i.e., the premium for using regulating volumes. Jaehnert et al. (2009) used data from the Nordic market to support the research, focusing specifically on southern Norway. An interesting and important aspect of Jaehnert et al.'s (2009) work was the creation of a model that would enable the exploration of cross-border regulating volumes across high-voltage direct current interconnectors. In Chapter 6 the effect of cross-border energy flow is explored but it is based on pricing outcomes related to the day-ahead market. The results showed that cross-border trading can have a large effect on pricing outcomes between different Nordic trading partners and, like the spot market, there is importing and exporting that can occur within the regulating market that helps to control imbalances.

These benefits spilled over into the regulating market, which is why Jaehnert and Doorman (2012) discuss the importance of integrating the Nordic regulating markets, stating the key position that Norwegian hydropower could potentially serve a pivotal role in balancing the system. Since the publication of Jaehnert and Doorman's (2012) research, the TSOs of the Nordic regulating market are working to form a common balancing initiative that will make the balancing rules apply to all (Ilieva and Bolkesjø, 2014). Ilieva and Bolkesjø (2014) explore how these regulatory changes would change the regulating prices in different Nordic areas. Contrary to Skytte's (1999) findings, who found up-regulating prices were more influenced by up-regulating volumes, Ilieva and Bolkesjø (2014) found the down-regulation price to be more sensitive to regulating volumes than up-regulating prices. In addition, their results showed that the sensitivity varied greatly across the different Nordic areas (Ilieva and Bolkesjø, 2014). Of these papers discussed, only Jaehnert et al. (2009) captured the effect of forecasting error by using the difference between the spot price and regulating price, while none incorporated wind energy directly.

3.5 The Balancing Market

The balancing market was not investigated in this dissertation. However, below, a brief description has been provided, to provide a complete overview of the Nordic markets.

The balancing market operates almost exactly the same as the regulating market, except that the transactions occur after the delivery hour, at which point the metered data is available along with the imbalance being quantified. There are three forms of prices used in settlement in the balancing market (Nord Pool, 2017e):

- Imbalance price production purchase: The down-regulating price of the hour is the price of production imbalance power purchased by the TSO from a BRP. If no down-regulation has been made or if the hour has been defined as an up-regulation hour, the Elspot area/zone price is used as the purchase price of production imbalance power.
- Imbalance price production sale: The up-regulating price of the hour is the price of production imbalance power sold by the TSO to a BRP. If no up-regulation has been made or if the hour has been defined as a down-regulation hour, the Elspot area/zone price is used as the selling price of production imbalance power.
- Imbalance price consumption: The price for which the TSO both purchases imbalance power from a BRP and sells it. In the case of a regulating hour, the regulation price is used. If no regulation has been made, the Elspot zone price is used as the purchase and selling price of consumption imbalance power.

4 Descriptive Analysis of Nord Pool Market Data

This chapter describes how the raw data from Nord Pool is presented and how it was transformed. Section 4.2 is a descriptive overview of the Nordic market, while Section 4.3 is a descriptive analysis of the Nordic market before and after Nord Pool coupled with the Central Western European market, and it investigates the first research objective.

4.1 Data Preparation

To support this research, data was retrieved from Nord Pool using two methods. Prior to 2013, access to any Nord Pool data was granted by special request. Student access was free and a link to Nord Pool's ftp server was provided. Nord Pool organized the data in several main categorizes that included data files for Elspot, Elbas, and the Operating System. There were also files for exchanges rates, because any currency data was presented in the nation's own currency. Therefore, to compare prices, for example, the exchange rates were required. The exchange rates were at the daily level and weekends were omitted. In order not to lose data for Saturday and Sunday, the Friday's exchange rate was applied to those days.

For each year of data and for each Nordic country, there would be 52 or 53 files, corresponding to the number of weeks in the year. Each file was downloaded manually and saved. In all, roughly 4,992 files were downloaded. To prepare the data for analysis, the raw files needed to be transformed. An image of an original, raw datafile has been listed in the Appendix as Figure A.1. To perform this task, five Perl scripts were written, each performing its own set of commands. Please refer to Appendix A for an example of such a script.

A feature of the raw data was that Nord Pool assigned a unique code for each type of variable. For example, in the Elspot file there were four types of data presented that had the same time stamp. Furthermore, since there was more than one area in the day-ahead market, some of these variables were multiplied by the number of areas. Those were: the system price, the area price, and the total turnover for that area. It should be noted, that any data after 2012 may now be retrieved directly from the Nord Pool website and the unique codes are no longer used inside files with multiple variables. Rather, the data files are presented by category using clickable links where the user selects the data desired.

A keystone component of this research was linked to cross-border energy flow. Power exchanges across HVDC interconnectors at the hourly level are unilateral, meaning that power cannot be exported by both partners within the same period. Thus, there becomes an exporter and importer at period i. Table 5 is an example of how cross-border energy flow was presented in the raw file retrieved from the Nord Pool ftp server. It shows that in hour 1, western Denmark (DK1) exported 150 MWh to eastern Denmark (DK2). In hour 2, there was no trading, which also indicates that the zonal prices between these two areas should be equal to one another. In hour 3, western Denmark imported 45 MWh from eastern Denmark. Accordingly, the direction of the energy flow will be determined by prices. Table 6 presents prices constructed based on the flow pattern shown in Table 5. The energy flows from the low-priced area to the high-priced area.

Table 5 Adaptation of Nord Pool Spot's hourly Elspot flow code.

	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6
			MWh			
DK1_DK2	150	0		145	146	0
DK2_DK1		0	45			0

When relevant, all price series were converted to 2015 real terms using the Harmonized Consumer Price Index for Danish electricity. The original price data is at the hourly level, while the index is at the monthly level. Therefore, it was decided to use the same index on prices so that small differences would not be masked due to the differences in temporal aggregation.

Table 6 Example of day-ahead spot prices based on flow patterns in Table 5.

	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6
			€/MWh			
DK1	31.3	36.5	24.3	30.9	31.5	34.2
DK2	32.8	36.5	22.6	33.4	32.1	34.2

One issue arose during the data preparation stage. A question was sent to Nord Pool asking if Danish wind production was a share of total production, or to determine total production should wind production be added to production values. Initial communication from Nord Pool stated that wind production was a share of total production. To test this definition, a quotient of wind production and total production was calculated. The quotient should not exceed one, and it was found that this rule was broken. Nord Pool was notified. Nord Pool contacted the Danish TSO regarding this inquiry. The Danish TSO replied that the definition changed in October 2015 and that wind production was no longer quantified as a share of total production. To calculate total production after this date, a researcher had to now add production and wind production.

4.2 The Day-Ahead Market

Due to changes related to the geographical zones (see Table 2), the figures and tables presented in this section have been limited to 2012 – 2016. In limiting the range to these years, a descriptive analysis may be performed on any of the Nordic bidding areas, since the last major split of bidding areas occurred in November 2011. At that time Sweden, which had always constituted one area, was split into four areas.

Table 7 is a descriptive overview of area prices for all twelve Nordic areas. The abbreviations used for each bidding area by Nord Pool in Table 7 are listed in Table 3. The system price is also the unconstrained market clearing price. It is calculated, assuming that there are no physical constraints on the transmission system and that it is where the aggregate supply and demand curves cross. Only western Denmark (DK1) and eastern Denmark (DK2) experience negative prices, although minimum prices for the other Nordic areas approach zero. When comparing the areas at the national level, there are differences. The lowest prices correspond to the five Norwegian areas, while the highest average is 34.5 EUR/MWh for Finland. In addition, Finland's area price on average had the highest level of variation, followed by eastern Denmark (DK2). The Danish areas had the smallest values for skewness, indicating a more symmetric distribution than the other ten areas. Finally, the kurtosis values were large, which may indicate that the larger variance at the fourth moment was a result of infrequent extreme deviations. Electricity prices are susceptible to prices shocks when unexpected events occur, such as droughts or extreme cold temperatures.

Table 7 Descriptive statistics for day-ahead spot prices (EUR/MWh) in 2015 real terms for Nordic areas from 2012 to 2016.

	System Price	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
	N (43,739)												
Median	29.5	30.9	32.2	34.5	27.6	27.4	30.6	29.3	27.4	30.7	30.7	30.9	31.5
Mean	29.8	31.4	33.2	35.7	28.5	28.1	30.8	29.8	28.1	30.9	31	31.4	32.2
Std. Dev.	10.9	13.8	14.7	14.8	11.2	10.2	11.4	11.1	10.6	12.0	12.0	12.7	13.2
Min.	1.1	-208.8	-208.8	0.3	0.6	0.6	1.1	1.4	0.6	0.3	0.3	0.3	0.3
Max.	228.6	213.4	258	313.2	238.2	213.4	258	258	213.4	258	258	258	258
Skewness	2.4	0.0	1.1	2.9	2.5	1.3	2.5	2.7	1.5	2.4	2.4	2.7	2.5
Kurtosis	31.5	21.4	28.4	30.8	30.3	14.5	32.9	36.9	17.7	29.3	29.2	30.3	25.9

Figure 5 presents five day-ahead spot price series. Each Nordic country is represented and when there is more than one area in a country, which applies to Denmark, Norway, and Sweden, the first area was selected. The five price series presented in Figure 5 are: the unconstrained market clearing price (system price); Western Denmark (DK1); Oslo, Norway (NO1); Lulea, Sweden (SE1); and Finland (FI). Figure 5 shows a general trend that in most months Oslo's (NO1) day-ahead price was lower than the spot price. In addition, the figure shows that prior to July 2013, Finland and western Denmark switched places in terms of which price series had the highest average. After July 2013 and until December 2016, Finland had the highest average spot price.

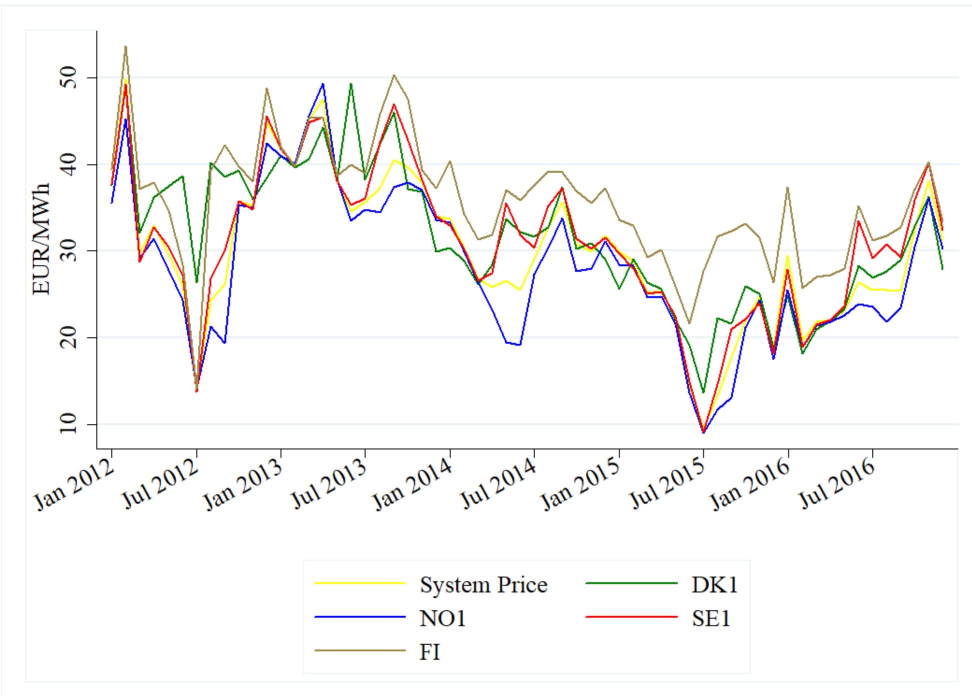


Figure 5 Monthly average day-ahead spot prices (EUR/MWh) in real 2015 terms for system price for western Denmark (DK1); Oslo, Norway (NO1); Lulea, Sweden (SE1); and Finland (FI).

At the market clearing price for each area, Nord Pool publishes the hourly buying and selling volumes. Using the same areas that were presented in Figure 5 (DK1; NO1; SE1; FI), Figure 6 presents the average monthly buying and selling volumes. Figure 6 shows that on average Finland's and Norway's buying volume, 6,152 MWh and 3,926 MWh, respectively, is higher than their average selling volume (4,551 MWh and 2,494 MWh). In contrast, Sweden's selling volume was on average 1,300 MWh higher than its buying volume. There was no large difference between western Denmark's average values, although its average selling volume (1,962 MWh) was higher than its average buying volume (1,924 MWh). The series presented in Figure 6 also show that there are large seasonal differences in average buying and selling volumes, especially for Finland and Norway, where the highest values correspond to the colder months.

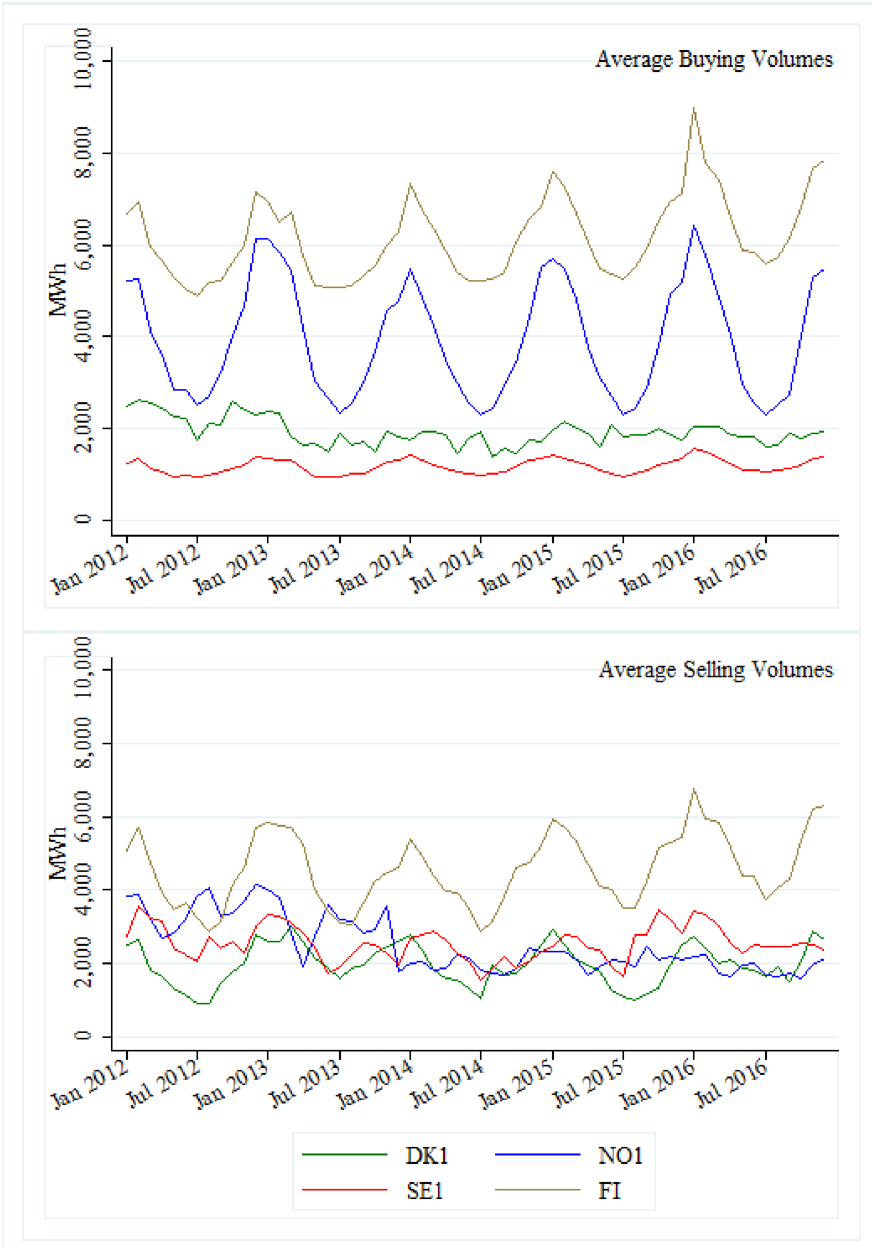


Figure 6 Monthly average buying and selling volumes in the day-ahead spot market for western Denmark (DK1); Oslo, Norway (NO1); Lulea, Sweden (SE1); and Finland (FI).

Another perspective to evaluate the day-ahead market is to explore the price differences that occur between the different sets of trading partners. There are nine sets of trading partners listed in Table 8. The sets of partners were selected based on the criteria that all Nordic areas were represented by having at least one area and also which areas were interconnected to the Central Western European market (see Table 4).

The different sets of trading partners may be categorized into two groups: international trading partners and intra-national partners. For example, DK1-DK2 or NO2-NO1 would be classified as intra-national trading partners, while DK1-NO2 would be grouped as being international trading partners. From this viewpoint, the values that represent the prevalence of price differences between trading partners show a general trend. On average there is a higher prevalence of price differences between international trading partners than with intra-national trading partners. In Table 8, western Denmark has three trading partners (DK2, NO2, and SE3). On average, the total percentage when there were price differences between DK1-NO2 and DK1-SE3 were 53.1% and 41.8%, respectively. In contrast, roughly 73% of the time, there was no price difference between DK1-DK2. This corresponding value was even higher between SE4-SE3 (93.3%).

Building upon Table 8, Table 9 presents the descriptive statistics for the calculated price differences (EUR) in 2015 real terms between the nine sets of Nordic trading partners. If the average value is negative, this indicates that the second trading partner listed, on average, had a higher area price that the first trading partner listed. While the price difference was minimal (-0.4 EUR), this negative value showed that on average NO1 had a higher area price than NO2. This was also true for DK1-DK2, although the average price difference was -1.5 EUR. The largest price differences occurred between the Finnish and Swedish trading areas. The corresponding average price differences were 4.8 EUR and 4.3 EUR, with Finland's average price always higher.

Which area has the higher area price determines the direction of the planned energy flow. It should always flow from the surplus area (low-priced area) to the deficit area (high-priced area). The final component of the data published by Nord Pool for the day-ahead market is the planned energy flow that occurs on the interconnectors. Table 10 shows the nine Nordic trading partners that have been presented in earlier tables (see Table 8 and Table 9) and the average volume (MWh) that was either exported or imported. According to Table 10, the area that exports the most volume is southern Norway. On average, southern Norway (NO2) exports 1,432.0 MWh to eastern Norway (NO1). As expected, Finland imports much larger volumes of energy from its Swedish trading areas (SE1 and SE3) than it exports. For example, on average, Finland imports 1,153.9 MWh from Sweden (SE1), and when it exports the average volume is roughly 36 times smaller (35.3 MWh).

Table 8 The number of hours per year when there were price differences in the day-ahead spot market between different sets of Nordic trading partners.

	2012	2013	2014	2015	2016	Total	2012	2013	2014	2015	2016	Total
DK1-DK2			N						Col.%			
No Price Difference	7,613	6,166	6,299	6,763	5,007	31,848	86.70%	70.40%	71.90%	77.20%	57.00%	72.60%
Price Difference	1,171	2,594	2,461	1,997	3,776	11,999	13.30%	29.60%	28.10%	22.80%	43.00%	27.40%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
DK1-NO2												
No Price Difference	3,916	3,397	3,037	5,583	4,650	20,583	44.60%	38.80%	34.70%	63.70%	52.90%	46.90%
Price Difference	4,868	5,363	5,723	3,177	4,133	23,264	55.40%	61.20%	65.30%	36.30%	47.10%	53.10%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
DK1-SE3												
No Price Difference	4,836	4,969	4,765	5,912	5,018	25,500	55.10%	56.70%	54.40%	67.50%	57.10%	58.20%
Price Difference	3,948	3,791	3,995	2,848	3,765	18,347	44.90%	43.30%	45.60%	32.50%	42.90%	41.80%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
DK2-SE4												
No Price Difference	5,973	6,934	6,904	7,395	7,978	35,184	68.00%	79.20%	78.80%	84.40%	90.80%	80.20%
Price Difference	2,811	1,826	1,856	1,365	805	8,663	32.00%	20.80%	21.20%	15.60%	9.20%	19.80%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
NO2-NO1												
No Price Difference	7,475	7,756	8,269	8,318	7,466	39,284	85.10%	88.50%	94.40%	95.00%	85.00%	89.60%
Price Difference	1,309	1,004	491	442	1,317	4,563	14.90%	11.50%	5.60%	5.00%	15.00%	10.40%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

(*Continued*)

Table 8 (Continued) The number of hours per year when there were price differences in the day-ahead spot market between different sets of Nordic trading partners.

	2012	2013	2014	2015	2016	Total	2012	2013	2014	2015	2016	Total
NO2-NO5			N						Col.%			
No Price Difference	6,573	7,243	8,050	8,222	6,750	36,838	74.80%	82.70%	91.90%	93.90%	76.90%	84.00%
Price Difference	2,211	1,517	710	538	2,033	7,009	25.20%	17.30%	8.10%	6.10%	23.10%	16.00%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
SE4-SE3												
No Price Difference	7,774	8,203	8,519	8,101	8,319	40,916	88.50%	93.60%	97.20%	92.50%	94.70%	93.30%
Price Difference	1,010	557	241	659	464	2,931	11.50%	6.40%	2.80%	7.50%	5.30%	6.70%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
FI-SE1												
No Price Difference	5,373	7,025	4,575	4,331	5,833	27,137	61.20%	80.20%	52.20%	49.40%	66.40%	61.90%
Price Difference	3,411	1,735	4,185	4,429	2,950	16,710	38.80%	19.80%	47.80%	50.60%	33.60%	38.10%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
FI-SE3												
No Price Difference	5,660	7,143	4,719	4,636	5,909	28,067	64.40%	81.50%	53.90%	52.90%	67.30%	64.00%
Price Difference	3,124	1,617	4,041	4,124	2,874	15,780	35.60%	18.50%	46.10%	47.10%	32.70%	36.00%
Total	8,784	8,760	8,760	8,760	8,783	43,847	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 9 The average price differences (EUR) in 2015 real terms between different Nordic trading partners from 2012 to 2016.

	DK1-DK2	DK1-NO2	DK1-SE3	DK2-SE4	NO2-NO1	NO2-NO5	SE4-SE3	FI-SE1	FI-SE3
N	43,744	43,744	43,744	43,744	43,744	43,744	43,744	43,744	43,744
Mean	-1.5	3.5	0.2	1	-0.4	0.1	0.8	4.8	4.3
Std. Dev.	21.9	23.7	23.1	7.4	3.7	2.1	3.9	10.2	9.5
Min.	-178.2	-244.4	-244.9	-244.9	-195.9	-165.8	-3.9	-4	-54.8
Max.	2,024.70	2,027.30	2,024.70	86.5	6.5	37.2	94.1	241.8	241.8

Table 10 Descriptive statistics for planned energy flow(MWh) between Nordic trading partners from 2012 to 2016.

	DK1-DK2		DK1-NO2		DK1-SE3		DK2-SE4	
	Export	Import	Export	Import	Export	Import	Export	Import
N	34,604	2,612	11,074	29,844	22,551	13,809	13,709	28,514
Mean	441.3	152.1	734.4	846.7	436	429.5	595.4	776.3
Std. Dev.	190.7	146.3	430.1	405.4	238.4	247.6	370.8	417
Min.	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Max.	590	600	1,632	1,532	740	680	1,700	1,300
Skewness	-0.9	1.1	0.1	-0.1	-0.1	-0.4	0.3	-0.2
Kurtosis	2.5	3.6	2.2	2.4	1.8	1.6	2.3	1.7
	NO2-NO1		NO2-NO5		SE4-SE3			
	Export	Import	Export	Import	Export	Import		
N	33,399	7,721	7,885	14,129	1,197	35,687		
Mean	1,432.30	591.6	156.3	300.4	325.9	2,844.50		
Std. Dev.	799.3	493.4	111.6	181	258.4	1378.2		
Min.	0.1	0.1	0.1	0.1	0.1	0.1		
Max.	3,400	1,900	400	600	1,282.30	5,558.30		
Skewness	0.1	0.7	0.6	-0.1	1	-0.3		
Kurtosis	2.2	2.5	2.6	1.9	3.4	2		
	FI-SE1		FI-SE3					
	Export	Import	Export	Import				
N	218	35,853	1,708	33,159				
Mean	35.3	1,153.90	277.3	911.6				
Std. Dev.	80.4	417.5	292	363.6				
Min.	0.1	0.1	0.1	0.1				
Max.	411.4	1570	1350	1350				
Skewness	2.6	-1.1	1	-0.9				
Kurtosis	9.2	3	3.2	2.7				

4.3 The Day-Ahead Market and the Central Western European market

In the previous section, the trading relationships between different sets of Nordic trading partners were explored. In this section, the focus shifts to the four HVDC interconnectors between the Nordic and Central Western European markets. While Nord Pool publishes pricing data for the Nordic areas, it does not publish pricing data for the Central Western European market.

In January 2011, the Nordic market coupled with the Central Western European market so that there were four interconnectors that linked the two regions (see Table 4). While the flow of electricity across these interconnectors is used as buying or selling volumes for the relevant Nordic area day-ahead price (Nord Pool, 2017e), Figure 7 shows that after January 2011 there was a downward trend in the monthly average system price after this event occurred. Figure 7 was constructed by aggregating the hourly values for the Nord Pool system price to the monthly level over a period of sixteen years (2000-2016). The figure shows that the system price has been volatile, which is an inherent feature of electricity prices due to limited storability, inelastic demand, and constant transmission balance (Geman and Roncoroni, 2006; Escribano et al., 2011).

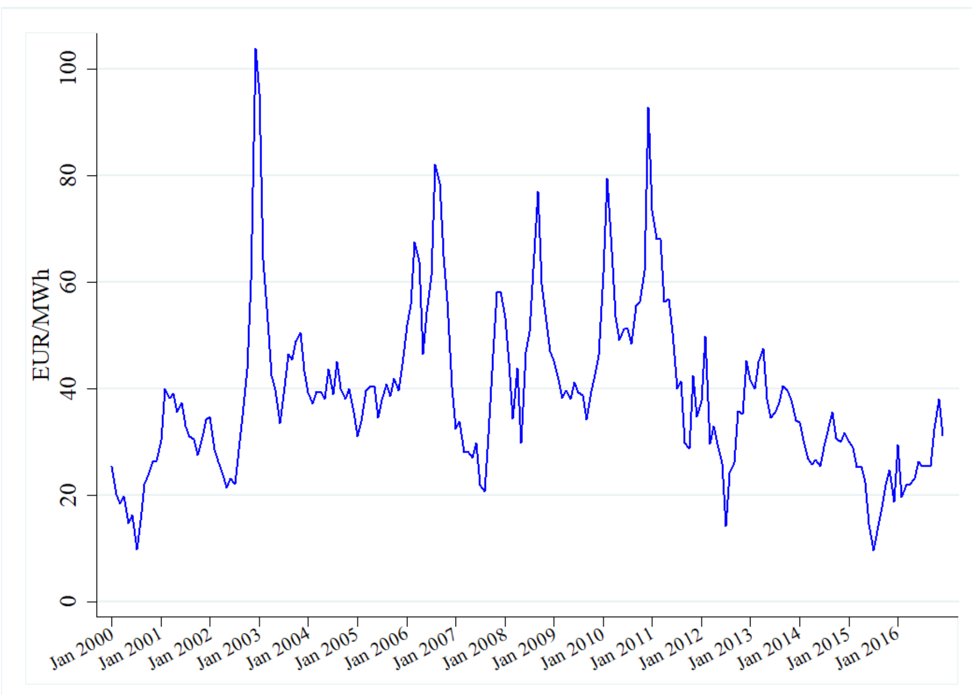


Figure 7 The monthly average day-ahead system price (EUR/MWh) in 2015 real terms from 2000 to 2016.

A student's t-test was used to identify if there was a significant difference in the system price, after controlling for this market change. Table 11 shows the results. To investigate if market coupling was linked to the non-stationary averages and if the student *t*-test was valid, three time frames were tested, a one year before and one year after market coupling (2010-2011) and then with two longer time frames. The results show in the first test that there was a significant difference at the 90% confidence level and that the confidence level grew as the time period increased.

Table 11 Descriptive statistics of the monthly average system price (EUR/MWh) in 2015 real terms before and after the Nordic day-ahead market coupled with the Central Western European market.

	Before CWE	After CWE	Before CWE	After CWE	Before CWE	After CWE
	2010	2011	2009	2012	2008	2013
N	12	12	24	24	36	36
Mean (EUR/MWh)	60.6	49.2	50.5	40.7	50.5	40.3
Std. Dev.	13.4	15.4	14.1	15.3	13.4	12.6
Student t-statistic	1.93		2.31		3.32	

The only data that Nord Pool publishes is total transfer capacity and the planned energy flow. In addition, the times series data for net transfer capacity data begins in 2013. This explains the discrepancy in years and why Table 14 only presents the years 2013 to 2016.

It was discussed earlier that there are four market interconnectors between the Nordic and Central Western European markets. Table 12 presents the trading relationship for different sets of trading partners (DK1-DE, DK2-DE, NO2-NL, and SE4-DE) across these market interconnectors by showing the number of hours when one area either exported, imported, or did not trade energy from 2012 to 2016. The values have been shaded either light gray or dark gray. Dark gray indicates that the prevalence for that trading alternative was greater than or equal to 50%, while light gray corresponds to percentages less than 50%. The trading relationship between southern Norway (NO2) and the Netherlands shows that almost always southern Norway is exporting energy to the Netherlands. For example, in 2015, 98% of the time southern Norway exported energy to the Netherlands. In contrast, the two partners with the highest percentage of not trading were DK1-DE. In 2016, roughly 39% of the time, there was no planned energy flow between the two partners.

What cannot be seen in Table 12 is a comparison of the different distributions for trading alternatives (exporting, importing, or no trading) between different sets of trading partners. To look at the trading relationship from this perspective, DK1-DE and DK2-DE have been selected, since it can be assumed that DK1 and DK2 will have similar consumption patterns due to having a similar geographical location. A Pearson's χ^2 test was performed to test the level of independence and to see if DK1-DE's trading was independent from DK2-DE's trading pattern. The results from the test ($p < 0.001$) showed that the null hypothesis, which states that there is no difference in the distributions, could be rejected at the 99% confidence level.

Table 12 The number of hours tabulated across years (2012-2016) for trading alternatives (exporting, importing, or no trading) between Nordic and Central Western European partners.

	DK1-DE			DK2-DE		
	No Trade	Export	Import	No Trade	Export	Import
2012 (N=8,784)	288 (3%)	7,330 (83%)	1,166 (13%)	1,287 (15%)	6,102 (69%)	1,395 (16%)
2013 (N=8,759)	598 (7%)	3,462 (40%)	4,699 (54%)	904 (10%)	2,732 (31%)	5,123 (58%)
2014 (N=8,759)	1,759 (20%)	3,980 (45%)	2,986 (34%)	803 (9%)	4,130 (47%)	3,826 (44%)
2015 (N=8,759)	3,983 (45%)	3,371 (38%)	1,405 (16%)	631 (7%)	6,422 (73%)	1,706 (19%)
2016 (N=8,782)	3,410 (39%)	1,992 (23%)	3,380 (38%)	1,188 (14%)	3,795 (43%)	3,799 (43%)
	NO2-NL			SE4-DE		
	No Trade	Export	Import	No Trade	Export	Import
2012 (N=8,784)	304 (3%)	8,8269 (94%)	211 (2%)	2,404 (27%)	5,512 (63%)	868 (10%)
2013 (N=8,759)	1,612 (18%)	6,572 (75%)	575 (7%)	3,162 (36%)	2,326 (27%)	3,271 (37%)
2014 (N=8,759)	296 (3%)	8,216 (94%)	247 (3%)	2,254 (26%)	3,832 (44%)	2,673 (31%)
2015 (N=8,759)	147 (2%)	8,574 (98%)	38 (0%)	3,110 (36%)	4,633 (53%)	1,016 (12%)
2016 (N=8,782)	993 (11%)	7,167 (82%)	622 (7%)	2,749 (31%)	3,255 (37%)	2,778 (32%)

Table 13 The trading alternatives between DK1-DE and DK2-DE tabulated across one another from 2012 to 2016.

		DK2-DE			
		No Trade	Export	Import	Total
DK1-DE	No Trade	701	7,151	2,220	10,072
	Export	2,929	16,000	1,206	20,135
	Import	1,183	30	12,423	13,636
	Total	4,813	23,181	15,849	43,843
	$p < 0.001$				

To explore the utilization of the market interconnectors further, Table 14 was constructed to present the average percentage of the capacity used when one area either exported or imported energy with one another. Table 4 listed the maximum net capacities for the four interconnectors. Table 14 shows that in all years, and no matter the direction of flow, most of the capacity on the interconnectors was being utilized. The lowest values correspond to NO2-NL. For example, in 2015, less than 50% (41.6%) of the total capacity on the NorNed interconnector was used when southern Norway (NO2) imported from the Netherlands. However, in this same year and when Norway exported energy to the Netherlands, almost all (99%) of the total capacity on the interconnector was used.

Table 14 Average percentage of the capacity used in the HVDC interconnectors that connect Nordic and Central Western European markets.

	DK1-DE		DK2-DE	
	Export	Import	Export	Import
	Mean % (Std. Dev.)	Mean % (Std. Dev.)	Mean % (Std. Dev.)	Mean % (Std. Dev.)
2013	83.7 (28.8)	78.0 (31.9)	83.3 (28.0)	88.3 (26.8)
2014	86.38 (25.6)	72.7 (33.5)	87.5 (27.8)	84.6 (29.8)
2015	95.8 (15.6)	71.4 (32.3)	93.2 (19.5)	77.9 (35.5)
2016	91.0 (23.0)	65.6 (33.9)	89.6 (24.1)	84.4 (30.9)
	NO2-NL		SE4-DE	
	Export	Import	Export	Import
	Mean % (Std. Dev.)	Mean % (Std. Dev.)	Mean % (Std. Dev.)	Mean % (Std. Dev.)
2013	93.4 (20.1)	59.8 (35.0)	79.3 (34.4)	93.9 (16.9)
2014	96.9 (13.8)	58.4 (33.9)	88.4 (27.2)	94.3 (18.9)
2015	99.0 (8.0)	41.6 (31.8)	95.1 (17.5)	96.9 (14.0)
2016	90.9 (23.4)	61.8 (35.8)	86.4 (28.6)	91.1 (23.18)

Note: Total capacity data was available only from 2013 to 2016, while cross-border energy flow data across market coupling HVDC interconnectors is available from 2012 to 2016. Therefore, values for 2012 in this table cannot be calculated.

Table 15 provides a descriptive overview on the prevalence of price differences under different trading alternatives between the Nordic country and a Central Western European member country. For example, western Denmark trades with Stockholm, Sweden (SE3), while DK1 also has an HVDC interconnector to Germany. Therefore, the price differences between DK1-SE3 are tabulated across the three trading alternatives for DK1-DE. Table 15 shows that there is a higher prevalence (51.8%) of DK1 importing from DE when there is a price difference between itself and SE3. This is not the same for NO2 and NL. In this case, there is roughly the same prevalence of there being a price difference across all three trading alternatives, ranging from the lowest percentage 52.4% (export) to 59.2% (import).

Table 15 The number of hours from 2012 to 2016 when there was a price difference between Nordic trading partners tabulated across the trading alternatives between the respective Nordic area and Central Western European area.

	DK1-DE				Col.%			
DK1-SE3	No Trade	Export	Import	Total	No Trade	Export	Import	Total
No Price Difference	6,482	12,451	6,567	25,500	64.40%	61.80%	48.20%	58.20%
Price Difference	3,590	7,684	7,069	18,343	35.60%	38.20%	51.80%	41.80%
Total	10,072	20,135	13,636	43,843	100.00%	100.00%	100.00%	100.00%
	DK2-DE							
DK2-SE4	No Trade	Export	Import	Total	No Trade	Export	Import	Total
No Price Difference	4,288	17,803	13,093	35,184	89.10%	76.80%	82.60%	80.20%
Price Difference	525	5,378	2,756	8,659	10.90%	23.20%	17.40%	19.80%
Total	4,813	23,181	15,849	43,843	100.00%	100.00%	100.00%	100.00%
	NO2-NL							
DK1-NO2	No Trade	Export	Import	Total	No Trade	Export	Import	Total
No Price Difference	1,409	18,484	690	20,583	42.00%	47.60%	40.80%	46.90%
Price Difference	1,943	20,314	1,003	23,260	58.00%	52.40%	59.20%	53.10%
Total	3,352	38,798	1,693	43,843	100.00%	100.00%	100.00%	100.00%

As Table 15 only shows the number of hours when there was a price difference between defined sets of Nordic trading partners tabulated across corresponding Nordic-CWE trading alternatives, it does not show which price was higher or the average. Figure 8 and Figure 9 present these two descriptive statistics. If the price difference is negative, it is inferred that the other trading partner had a higher average price. For example, when western Denmark imports electricity from Germany, SE3's average spot price is 2.7 EUR/MWh higher than western Denmark. When exploring price differences between Nordic partners, under the western Denmark and Germany trading alternatives, the highest price difference (6.2 EUR/MWh) corresponds to western Denmark and southern Norway. Therefore, when western Denmark exports electricity to Germany, it can be expected on average that western Denmark will have a much higher average spot price than southern Norway. Eastern Denmark, on the other hand, almost always has a higher average spot price than its corresponding Nordic partners (DK1 and SE4), no matter whether it is importing, exporting, or not trading with Germany. There is one exception. When eastern Denmark imports from Germany, the highest average spot price belongs to SE4, although the difference is less than 1 EUR/MWh.

The key point shown in Figure 9 is that almost under all trading alternatives between southern Norway (NO2) and the Netherlands, the Nordic areas that trade with NO2 will have a higher price with one exception. When NO2 imports electricity from the Netherlands, on average, southern Norway will have a higher price than western Denmark on the order of 8.4 EUR/MWh. Therefore, based on the highest price difference, the key scenario that is shown in Figure 8 and Figure 9 is connected to western Denmark and southern Norway. When western Denmark needs to export electricity to Germany, it will have a much higher average spot price than southern Norway. Respectively, when southern Norway imports from the Netherlands, which occurs rarely (see Table 12), it will have a much higher average spot price than western Denmark.

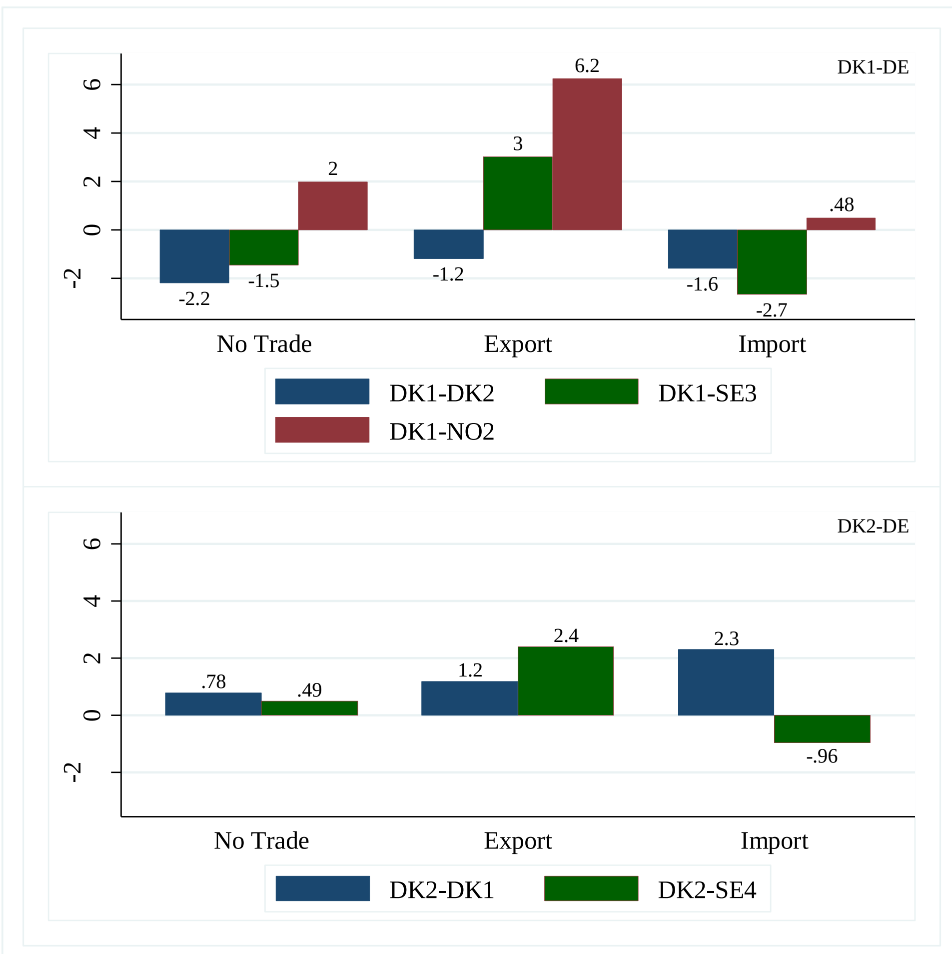


Figure 8 Annual average spot price difference between Nordic trading partners tabulated across Nordic and Central Western European trading alternatives.

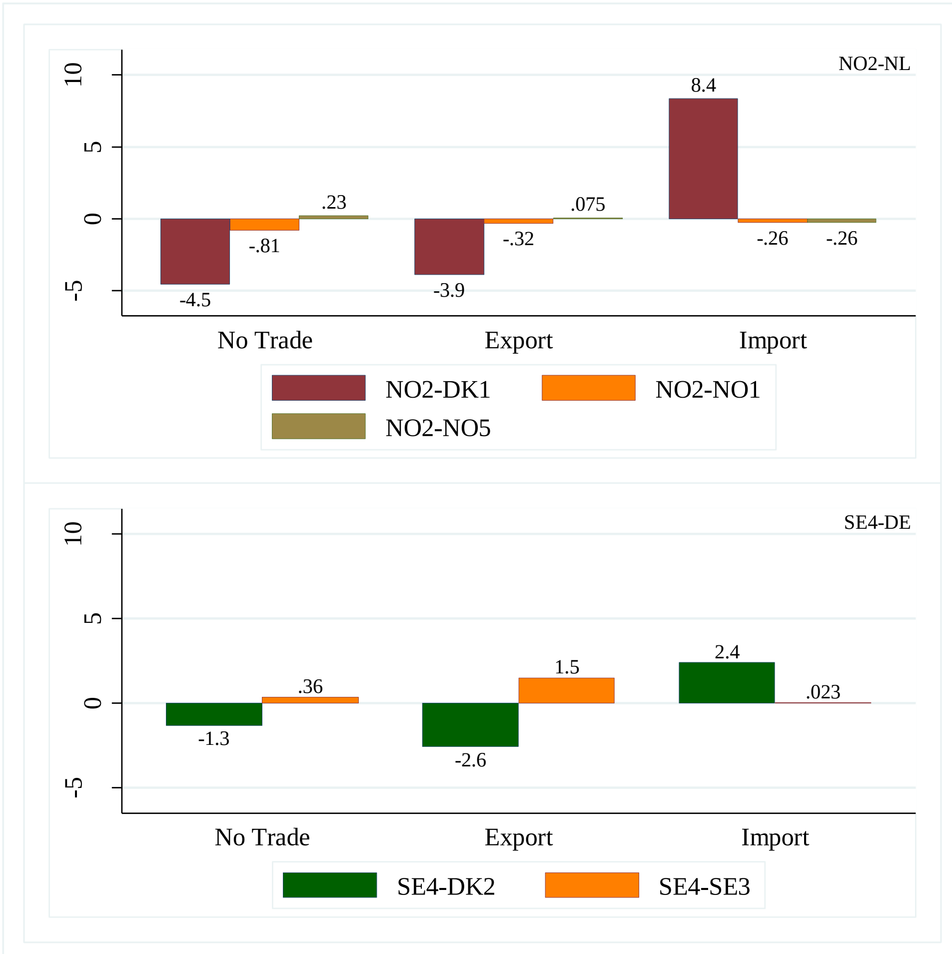


Figure 9 Annual average spot price difference between Nordic trading partners tabulated across Nordic and Central Western European trading alternatives.

Figure 10 shows the average price difference between western Denmark and its three Nordic partners, eastern Denmark (DK2), southern Norway (NO2), and Stockholm, Sweden (SE3) under the three trading alternatives (exporting, importing, or no trading) for western Denmark and Germany. Positive values indicate that western Denmark had a higher price than its Nordic partner, while negative prices indicate that the other area had a higher price. Figure 10 shows that most of the time western Denmark will have a higher price than southern Norway. However, there were two years (2012 and 2015) under the importing alternative, that southern Norway had a higher price, although the price difference did not exceed 2 EUR/MWh.

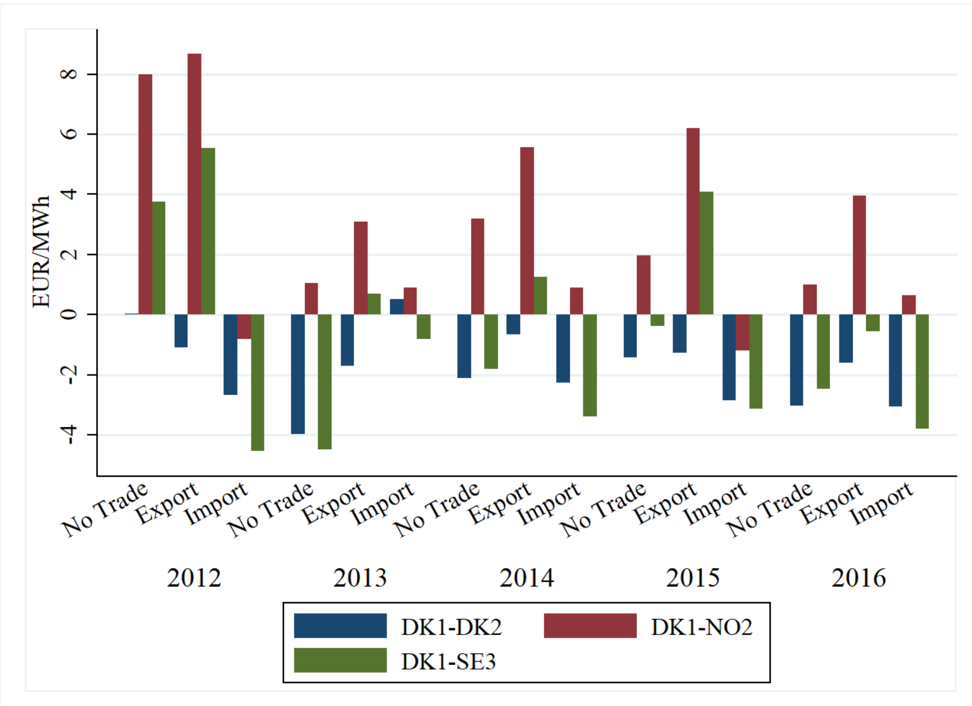


Figure 10 The average price difference between western Denmark and its three Nordic trading partners under different trading scenarios for western Denmark and Germany.

5 The Effect of Changes in the Nordic Electricity Supply on Danish and Finnish Electricity Prices

This chapter contains a peer-reviewed journal article:

Unger, E. A., G. F. Ulfarsson, S. M. Gardarsson, Th. Matthiasson, 2017: A long-term analysis studying the effect of changes in the Nordic electricity supply on Danish and Finnish electricity prices. *Economic Analysis and Policy*, 56:37–50. DOI: 10.1016/j.eap.2017.06.001

5.1 Introduction

5.1.1 The European Setting

In 1996, the first Internal Market in Electricity (IME) Directive was written by the European Parliament and went into effect in 1999. It is a document that outlines the preliminary steps for creating a higher level of market integration by joining international energy exchanges and making them into one Pan-European energy exchange (European Parliament and of the Council, 1996). By increasing the number of producers, accounting for the regional differences in demand patterns, and the energy flowing across borders, the IME was viewed as a way forward to not only increase energy security and competition, but to also reduce electricity prices (Helm, 2014). While European wholesale electricity prices have dropped (European Commission, 2014), to what degree the IME goals have been reached has come into question (Zachman, 2008; Bunn and Gianfreda, 2010). This too has been recognized by the European Commission and Regulation 714/2009/EC states "at present, there are obstacles to the sale of electricity on equal terms, non-discriminatory network access and an equally effective level of regulatory supervision do not yet exist in each Member State, and isolated markets persist" (European Parliament and of the Council, 2009).

5.1.2 Conflict between National Policies/Agendas

One example is limited interconnection between Spain and France (IEA, 2015b), where in Spain, wind energy produces roughly 20.4% of electrical supply (IEA, 2016a), and France, whose largest share of electricity (77%) is from the state-backed nuclear industry (IEA, 2016b). Spain's electricity interconnection capacity has remained low, with it being roughly only 4% of installed capacity in 2014 (IEA, 2015b). The first new interconnection of a 1.4 GW at Santa Llogaia–Baixas was inaugurated in February 2015 (IEA, 2015b). It had almost been three decades since the last interconnection project in Spain (IEA, 2015b). One hypothesis why interconnection has been so minimal is in part the fear of the impact that Spanish wind power would have on France's own national interests and its nuclear power industry (Oliver, 2014).

While the conflict between France and Spain is an example of a disconnect due to political objectives, in 2012 Norway and Sweden formed a common market for renewable electricity certificates (REC) (Blindheim, 2013). While Norway has been characterized as a country with exceptionally high wind resources, the REC common market has overall been ineffective in developing more wind power in Norway due to the political uncertainty created by the complaints of opponents (Blindheim, 2013). Furthermore, Norway and Sweden do not have feed-in-tariff policies such as Denmark, where generators using renewable energy sources are paid a premium per kilowatt hour of electricity produced; feed-in-tariffs have been found more effective in developing renewable energy than certificate programs (Mitchell et al., 2006). Wizelius (2014) claims that Sweden's use of "anything but feed-in-tariffs" has led to a muddled path for the development and ownership of wind power. So, while it was more optimal for Norway to develop a higher penetration of wind power, the overall share of wind power in Sweden climbed from 2.4% in 2010 to 7.3% in 2014 of total electricity production (IEA, 2016e, 2016f). In the same period of time, Norway's share of wind power also increased, but only from 0.7% to 1.5% (IEA, 2016c, 2016d). However, Sweden is moving into a position requiring it to find other energy sources to support its electricity generation as it seeks to remove 2.7 GW from its nuclear capacity (World Nuclear Organization, 2015).

5.1.3 Data Transparency

The examples cited illustrate how a range of factors can play a role in shaping the development of renewable energy sources and the common electricity market. The European Commission has called for more harmonization between countries (European Commission, 2014). However, for optimal plans to be designed, there must also be a high level of transparency and coordination between nations in terms of the data published that would support these types of analyses. The topic of data accessibility was addressed in 2011 when Regulation 1227/2011/EU, also known as the Regulation on Wholesale Energy Markets Integrity and Transparency (REMIT), went into force (European Parliament and of the Council, 2011). It obliged both transmission system operators and market participants to publish a range of "transparency data" (European Parliament and of the Council, 2011). The REMIT regulation has now been in effect for several years and there have been some improvements. However, there still remain large differences in the data published by the various stakeholders.

To illustrate this point, the Nordic market energy exchange, Nord Pool, publishes hourly wind energy data and weekly hydro-energy data, but no other categories such as nuclear or natural gas, for example. To obtain this type of data it is possible to go to the different national statistics agencies. Gaining the needed information, however, can be stymied as there is no standardized categorization for these types of data. In addition, the data may be presented at different temporal levels. For example, the Finnish Energy Agency now publishes hourly electricity supply data (2010-2015) but the data records thermal power divided into three different categories: cogeneration of district heat, industry, and separate electricity generation (Finnish Energy Agency, 2016). In contrast, for instance, Statistics Sweden publishes electricity supply data at a monthly level and categorizes its thermal generation into four types (Statistics Sweden, 2016). Assessments of electricity prices are often done at either the hourly or daily level (see, e.g., Jónsson et al., 2010; Gelabert et al., 2011). The issue that arises when estimating the effect of variables at different temporal resolutions is that either the fine scale variable needs to be aggregated or the coarse scale variable needs to be repeated as a constant for multiple fine scale observations. Both conditions will affect modeling. Also, due to differences in classification for power plants, a researcher needs to make subjective decisions as to how to group or classify power plants across nations, and such decisions might not be traceable in future assessments.

5.2 The Day-Ahead Market

In order to identify the limitations that still persist in electricity data, it was of interest to perform a long-term, multinational analysis that estimated the effect of various energy sources from many countries on national wholesale electricity prices. The Nordic day-ahead electricity spot market, Nord Pool, became fully integrated in 2000, when the Denmark grid finally became physically interconnected with the grids of Norway, Sweden, and Finland and with a single pricing mechanism for the entire region (Nord Pool, 2018c). Due to its longevity of operation, it allows a sixteen-year analysis (2000-2015). While this is a strength of the analysis, it also is a limitation, because there are only a few sources that publish electricity supply data in a standardized format that go this far back in time.

Nord Pool calculates an unconstrained market clearing price, which is based on all of the bids and offers from the market participants. All contracts for next-day delivery are submitted by 12:00 central European time (Nord Pool, 2017e). In reality, there are transmission constraints that constrict the flow of electricity, which becomes a cost that is passed on to the consumer (Singh and Papalexopoulos, 1998). Congestion is managed in Nord Pool by using geographical zones that are defined by the transmission system operators (Nord Pool, 2017e). Each market participant must indicate the area in which the bid or offer originated (Nord Pool, 2017e). The locational differences form different demand and supply curves, resulting in price differences between the areas and which result in arbitrage opportunities (Sioshansi et al., 2009). Implicit auctioning is a tool used by Nord Pool that is intended to level out locational price differences (Nord Pool, 2017e). After the initial prices have been calculated for each area, according to which area has the least supply (i.e., a higher area price), the transmission system operators will decide on a planned cross-border volume that may be exported from the lower priced area (surplus supply) to the higher priced area (Nord Pool, 2017e). The result is that the price differences are less or even equal (Nord Pool, 2017e). Hence, increased transmission capacities are critical in curtailing negative market behavior from producers (Borenstein et al., 1997; Shrestha and Fonseka, 2004; de La Torre et al., 2008; Küpper et al., 2009).

We hypothesize that, as the Nordic market becomes more interconnected (i.e., increased transmission capacity), the marginal effect on electricity prices will be less when there is a decrease in supply. The paper is organized as follows. Section 2 presents a description of how the Nordic market functions, along with the data description and methods. In Section 3, the results are presented with a discussion of findings, followed by the conclusions in Section 4.

5.3 Data and Methods

Currently, there are fifteen pricing areas in Nord Pool (Nord Pool, 2017a). However, only three price series were retrieved from Nord Pool for this analysis: 1) western Denmark (DK1), 2) Finland (FI), and 3) the Nordic market clearing prices (SP). The reason for limiting the number to these pricing areas (DK1 and FI) is because, over this period of sixteen years (2000-2015), there have been many additions and changes to the geographical boundaries of the pricing areas. For example, until October 2011 Sweden constituted only one pricing area. In November 2011, Sweden was divided into four areas (Nord Pool, 2017a). However, western Denmark and Finland's boundaries have not changed over the analyzed period. Given that the system price is unconstrained, it is assumed that these changes and additions have not affected the system price. It is acknowledged that this assumption is a limitation of the study that future research should attempt to resolve.

The original unit of the price series was euros per megawatt hour (EUR/MWh). All three spot price series were at the hourly level and then aggregated to the monthly resolution using the average value of the data. Before the data was aggregated to the monthly level, there was an inspection to identify extreme outliers. In 2009, Nord Pool implemented a negative pricing floor (Nord Pool, 2018d). Negative prices occur when there is a high supply of an inflexible energy source, such as wind, and extremely low demand (Fanone et al., 2013). The negative prices did not fall below -200 EUR/MWh. As Denmark continues to increase its electricity supply from wind generation, negative prices may occur more frequently; therefore, they were kept in the analysis. At certain times it was observed that spot prices jumped to extreme values (1,400 EUR/MWh) which occurred as the result of a shortage of supply when a Swedish nuclear plant went offline, coupled with unusually cold weather (Nord Reg, 2010). These data points were not omitted. Therefore, all data remained in the analysis.

In 2013, Nord Pool began publishing two hours with the exact same time stamp, so that there is one day in a year with 25 hours to account for daylight savings. To remove duplicates, in the case when the data was identical in both rows, one row was removed. In some years the rows with identical time stamps did not have identical data. This was handled by removing both observations, leaving the day with only 23 hours.

The prices were converted from nominal to real 2015 euros using the European Harmonized Consumer Price Index for Danish Electricity (Eurostat, 2016). While there are conversion indices for every nation, it was decided to use only the Danish Index for electricity on all three price series, since there is no index or system price for the Nordic region. This was to create a more standardized approach. Furthermore, since the price data was originally at the hourly level and the inflation data was at the monthly level, the use of different indices may mask other effects.

Figure 11 presents average monthly prices from January 2000 to December 2015 for the system price (SP), western Denmark (DK1), and Finland (FI) in 2015 real terms. The dynamics of hourly electricity prices are inherently volatile with mean-reversion (prices tend to fluctuate around a long-term equilibrium mean) due to seasonality (Huisman and Mahieu, 2003; Escribano et al., 2011; Janczura and Weron, 2010) the demand for electricity is inelastic, storability is limited (Borenstein, 2002), and the transmission system requires that there are only small frequency deviations (+/- 200 mHertz) from 50 Hertz (ENTSO-E, 2015). Since these average prices have been aggregated to a monthly resolution, hourly variance has been smoothed out. However, temporal correlations are still present, as shown in Figure 11.

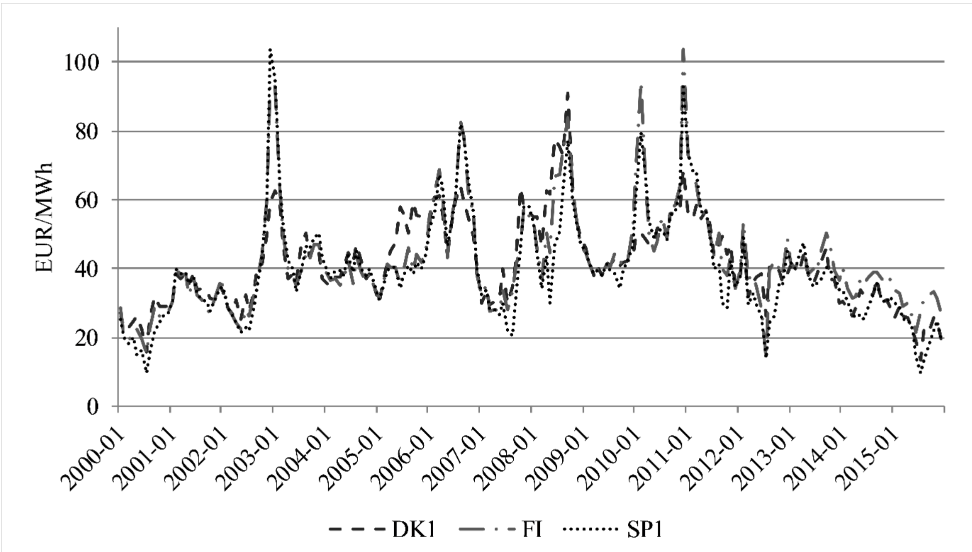


Figure 11 Monthly average spot prices in constant 2015 euros from Jan. 2000 to Dec. 2015

The price series presented in Figure 11 are described in Table 1 for the years 2000, 2005, 2010, and 2015. The highest annual mean prices and variability correspond to 2010 when the system price (SP1) was 60.6 EUR/MWh. The lowest averages for SP (21 EUR/MWh), DK1 (22.9 EUR/MWh), and FI (29.7 EUR/MWh) were observed in 2015.

Table 16 Annual spot price averages for the Nord Pool system price (SP), western Denmark (DK1), and Finland (FI) in 2015 real terms.

	SP				DK1				FI			
	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
	EUR/MWh											
2000	19.91	5.25	9.86	26.52	25.54	4.24	15.97	31.82	23.14	4.38	15.18	29.03
2005	38.61	3.81	30.97	44.60	48.95	9.30	30.05	59.18	40.00	4.59	31.21	46.23
2010	60.63	13.41	48.35	92.78	52.96	6.07	46.98	68.75	63.25	18.45	45.10	103.79
2015	21.01	6.35	9.58	29.90	22.94	4.23	13.69	29.10	29.68	3.66	21.58	33.60

Presented in Table 17 are the descriptive statistics for gross consumption, and indigenous electricity production (TWh), which is the sum of all electrical generation production (including pumped storage) measured at the output terminals of the main generators (IEA, 2016g), categorized by the different energy sources used to generate electricity (IEA, 2015a). The IEA offers a broader list of electricity supply data in terms of the different categories for energy sources; however, it is only provided at the annual level (IEA, 2016g). The electricity supply data at the monthly level is in gigawatt hours (GWh). There are four categories of energy sources: 1) combustibles fuels, 2) nuclear, 3) hydro, and 4) all other renewable energy sources (RES). While hydropower is considered to be from a renewable energy source, due to its ability to store energy and flexibility to meet demand, it stands as its own category.

Table 17 Descriptive statistics for monthly electricity generation mix and consumption in TWh (Source: IEA, 2015a; Nord Pool, 2016a).

	2000				2005				2010				2015			
	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
	TWh															
DK Gross Production	2.87	0.65	1.88	3.98	2.87	0.66	1.91	3.79	3.07	0.84	1.90	4.17	2.31	0.66	1.44	3.45
DK Gross Consumption	2.02	0.65	1.47	3.20	2.96	0.25	2.57	3.31	2.95	0.34	2.55	3.60	2.73	0.21	2.44	3.17
DK Combust. Fuels	2.51	0.56	1.66	3.46	2.31	0.50	1.60	3.17	2.42	0.75	1.47	3.44	1.08	0.47	0.44	1.87
DK Hydro	0.003	0.001	0.001	0.004	0.002	0.001	0.001	0.004	0.002	0.001	0.001	0.003	0.002	0.001	0.001	0.003
DK RES	0.36	0.11	0.20	0.51	0.55	0.20	0.31	1.08	0.65	0.16	0.40	0.90	1.23	0.27	0.89	1.89
FI Gross Production	5.61	0.86	4.51	7.00	5.65	1.23	3.70	7.39	6.43	1.37	4.68	8.36	5.50	0.68	4.50	6.48
FI Gross Consumption	6.31	0.57	5.39	6.93	6.99	1.34	4.11	8.54	7.09	1.16	5.63	9.12	6.78	0.79	5.78	8.27
FI Combust. Fuels	2.60	0.71	1.48	3.78	2.62	1.03	0.78	4.16	3.50	1.25	1.71	5.13	2.04	0.68	1.09	3.11
FI Nuclear	1.80	0.20	1.42	1.99	1.86	0.16	1.53	2.02	1.82	0.21	1.35	2.03	1.86	0.22	1.44	2.06
FI Hydro	1.20	0.20	0.84	1.49	1.13	0.18	0.78	1.40	1.06	0.16	0.89	1.48	1.38	0.21	1.12	1.79
FI RES	0.006	0.002	0.003	0.01	0.03	0.01	0.01	0.05	0.05	0.01	0.04	0.07	0.22	0.07	0.12	0.36
NO Gross Production	10.03	1.71	7.83	12.43	10.44	1.79	8.07	13.21	10.88	2.61	7.72	14.88	10.81	1.65	8.92	13.53
NO Gross Consumption	9.94	1.68	7.61	12.12	10.12	1.84	7.54	12.84	10.93	2.61	7.77	14.93	10.72	1.79	8.41	13.59
NO Combust. Fuels	0.05	0.01	0.04	0.06	0.07	0.01	0.06	0.09	0.45	0.12	0.23	0.62	0.26	0.01	0.24	0.29
NO Hydro	11.56	1.16	9.80	13.53	11.32	1.97	9.04	14.36	9.72	2.68	6.31	14.18	11.54	1.40	9.73	14.11
NO RES	0.009	0.003	0.01	0.02	0.05	0.02	0.03	0.08	0.09	0.03	0.05	0.14	0.24	0.06	0.15	0.33
SE Gross Production	11.80	1.95	8.72	14.35	12.88	1.61	10.77	15.53	12.11	1.58	9.56	14.74	13.18	1.30	11.25	14.94
SE Gross Consumption	11.86	1.76	9.16	14.23	12.19	2.13	9.02	15.19	12.20	2.52	9.06	16.22	11.24	1.65	8.94	14.03
SE Combust. Fuels	0.71	0.35	0.33	1.28	0.99	0.37	0.55	1.45	1.65	0.64	0.66	2.50	1.14	0.40	0.67	1.84
SE Nuclear	4.56	1.65	2.00	6.82	5.79	0.67	4.68	6.90	4.64	0.86	2.89	5.75	4.49	0.71	3.22	5.46
SE Hydro	6.49	0.74	5.49	7.66	6.02	0.71	4.67	7.06	5.53	0.89	3.81	7.28	6.16	0.47	5.33	6.82
SE RES	0.04	0.01	0.02	0.06	0.08	0.03	0.05	0.15	0.29	0.10	0.19	0.47	1.39	0.39	0.91	2.34

Table 17 shows that roughly 97% of electricity generated in Norway is from hydropower. While constituting an insignificant supply (< 1%) of electricity there is hydropower in Denmark, although in comparison to Sweden and Norway, Denmark's topographical features are relatively flat (World Atlas, 2015) and therefore not conducive to the use of hydropower to generate electricity. From 2010 to 2015, production from combustible fuel sources decreased for all four countries, while each country increased its share of production from RES. From 2000 to 2015, the percentage increase of Denmark's annual mean share of RES was 242%. Although, the total contribution of electricity supplied from RES compared to the other fuel types was much smaller for Norway, Finland and Sweden, there was a substantial percentage increase from 2000 to 2015. For example, in 2000, the mean number of GWh produced from RES in Finland was 6 GWh, and by 2015 this number had increased to 220 GWh, indicating that the amount of electricity supplied from Finnish RES was roughly 35 times higher in 2015 than it was in 2000. From 2000 to 2015, electricity suppled from RES in Sweden was approximately 34 times higher and 26 times higher in Norway.

Figure 12 shows the annual sum of the electricity generation mix and consumption for the year 2015 only. The relative difference in total production and consumption was large, with Sweden and Norway with high production, although the population was only 2 times higher in Sweden and similar in Norway compared to Denmark. The difference was due to development of heavy industries in these countries. The main imbalance in total country production and consumption was in Sweden and Finland, with Sweden being a net seller.

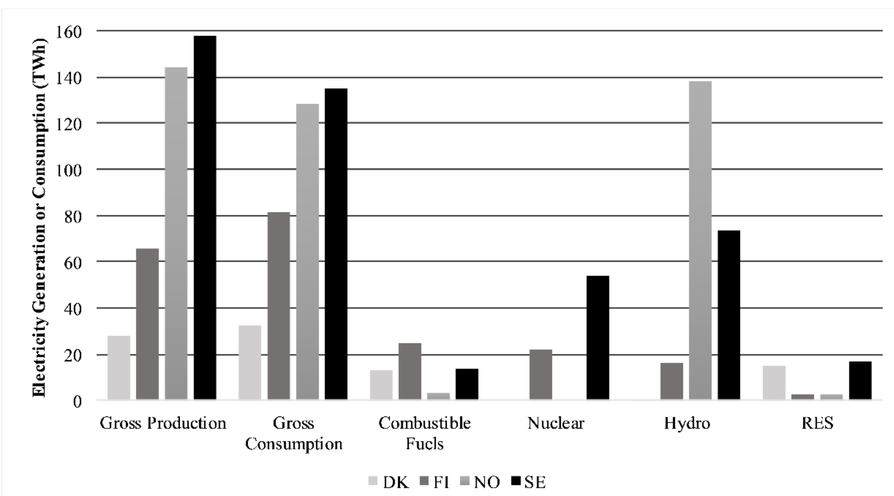


Figure 12 Annual sum of electricity generation mix and consumption in TWh in 2015.

National total gross consumption was calculated using hourly data from Nord Pool over the sixteen-year period by aggregating it to the monthly level to match the same temporal resolution of the IEA electricity supply variables. Table 17 shows that each country is growing in terms of consumption, although there was a slight decrease in 2015.

The physical constraints of the transmission system require a strong balance between supply and demand (Nord Pool, 2017e). As a result, there is a strong and positively correlated relationship between total demand and total production, as shown in Table 18. The table shows that there is only one correlation coefficient less than 0.6 and over half of the correlation coefficients are above 0.8. These high correlation coefficients show why it was not possible to insert all relative gross consumption variables into the respective model. This will be discussed in greater detail in the Methods section.

Table 18 Pearson's correlation coefficients for the Nordic countries' total supply and demand.

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	DK1 Gross Production	1.00							
(2)	FI Gross Production	0.74	1.00						
(3)	NO Gross Production	0.79	0.83	1.00					
(4)	SE Gross Production	0.83	0.86	0.96	1.00				
(5)	DK1 Gross Consumption	0.71	0.71	0.85	0.86	1.00			
(6)	FI Gross Consumption	0.74	0.86	0.88	0.88	0.81	1.00		
(7)	NO Gross Consumption	0.78	0.82	0.98	0.95	0.85	0.87	1.00	
(8)	SE Gross Consumption	0.66	0.76	0.79	0.80	0.58	0.67	0.79	1.00

Table 19 shows the Pearson's correlation coefficients between prices and all the electricity supply variables. The coefficients show that there is an inverse relationship between the renewable energy sources, including hydro, and price (System price, DK1 Area price and F1 Area price), except for Norwegian hydropower. In their *ex-post* analysis of daily Spanish spot prices, Gelabert et al. (2011) also found a positive relationship and explained this as because of the flexible nature of hydropower and its ability to store its energy in large reservoirs. Hence, unlike other renewable energy sources that have been shown to reduce market prices (see e.g., Clò et al., 2015; Cludius et al., 2014) but can also incur greater balancing costs due to their non-deterministic behavior (Koeppel and Korpås, 2008), hydropower, along with other conventional sources (Franco and Salza, 2011), may be dispatched in periods when demand is high, i.e., higher prices, creating a positive relationship between price and hydropower production.

Table 19 Pearson's correlation coefficients of monthly electricity supply levels.

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
(1)	System Price	1.00																
(2)	DK1 Area Price	0.68	1.00															
(3)	FI Area Price	0.91	0.67	1.00														
(4)	DK1 Combust. Fuels	0.46	0.27	0.37	1.00													
(5)	DK1 Hydro	-0.10	-0.22	-0.17	0.15	1.00												
(6)	DK1 RES	-0.07	-0.34	-0.06	0.07	0.36	1.00											
(7)	FI Combust. Fuels	0.46	0.21	0.4	0.78	0.23	0.22	1.00										
(8)	FI Nuclear	0.01	-0.12	-0.07	0.26	0.11	0.13	0.10	1.00									
(9)	FI Hydro	-0.21	-0.24	-0.2	0.02	0.20	0.15	-0.02	-0.33	1.00								
(10)	FI RES	0.00	-0.05	-0.08	0.17	0.11	0.22	0.18	0.06	0.08	1.00							
(11)	NO Combust. Fuels	0.13	0.03	0.12	0.12	0.12	0.02	0.12	0.19	-0.01	0.05	1.00						
(12)	NO Hydro	0.18	0.00	0.22	0.68	0.31	0.29	0.6	0.28	0.21	0.13	0.09	1.00					
(13)	NO RES	-0.09	-0.19	-0.14	0.21	0.18	0.41	0.23	0.22	0.16	0.61	0.13	0.21	1.00				
(14)	SE Combust. Fuels	0.40	0.06	0.31	0.78	0.37	0.31	0.76	0.31	0.1	0.2	0.21	0.71	0.33	1.00			
(15)	SE Nuclear	0.02	-0.16	-0.13	0.26	0.34	0.22	0.35	0.43	-0.11	0.08	0.15	0.17	0.19	0.43	1.00		
(16)	SE Hydro	-0.13	-0.16	-0.07	0.26	0.27	0.15	0.28	-0.16	0.55	0.02	-0.01	0.43	0.13	0.34	-0.02	1.00	
(17)	SE RES	-0.06	-0.2	-0.10	0.11	0.18	0.57	0.2	0.14	0.07	0.69	0.07	0.14	0.67	0.26	0.21	0.00	1.00

Unlike other intermittent renewable energy sources, hydropower may store its energy in reservoirs and may be dispatched to meet unpredictable load changes (Franco and Salza, 2011). Hence, hydropower may be used in periods of high demand, resulting in a positive correlation between production levels and prices (Gelabert et al., 2011).

Cross comparing the three price series showed that the Finnish day-ahead spot is much more positively correlated to the system price (0.91) than the Danish price is (0.68). While not all the years are shown in Table 17, on average, Denmark's indigenous production was greater than its consumption until 2010. In 2011, this changed, and Denmark's annual consumption exceeded its indigenous production levels. Finland, compared to Denmark, has on average from 2000 to 2015 consumed more electricity than it produced. One plausible explanation for the difference in the correlation coefficients may be tied to Denmark's high penetration of wind energy, which can induce congestion for several reasons such as limitations in the grid, effects from nearby turbines, or environmental factors (EWEA, 2017). Therefore, even when there is cross-border energy flow into Denmark to level price differences between areas, there still exists a price difference due to its high penetration of wind power, reducing average prices (Cludius et al., 2014; Jonsson et al., 2010; Woo et al., 2011). Furthermore, when there is not enough transmission capacity, this limits the flow of energy and price differences persist.

5.4 Methods

In all, three linear regression models were built, using the price series (SP, DK1, and FI) as the dependent variables. To control for the temporal fixed effects, every model included seasonal indicators ($s = 1, \dots, 3$). The seasons were defined as the following: 1) winter: December, January, and February; 2) spring: March, April, and May; 3) summer: June, July, and August; 4) fall: September, October, and November. The season, fall, was omitted from the model to prevent perfect multicollinearity. In addition to the seasonal indicator variables, a yearly binary variable ($y = 1, \dots, 11$) was created for each year, omitting the year 2000 to prevent perfect multicollinearity.

Table 20 shows at a national level which countries DK1 and FI trade within the day-ahead spot market. This table determined which supply and consumption variables entered which model. Since the Nordic system price is the unconstrained price all the electricity production, variables from each country were tested in the model. In the case of western Denmark, Finnish electricity supply variables were not used because western Denmark does not trade energy with Finland. However, the western Denmark model did include all the different types of production variables for Denmark, Norway and Sweden.

Table 20 Elspot trading partners.

	SP	DK1	FI
Denmark	X	X	
Finland	X		X
Norway	X	X	
Sweden	X	X	X

After all of the variables were inserted into the regression model, the hypothesis of non-significant difference from zero was tested for each coefficient on each variable using an asymptotic t-test (Greene, 2003). The statistical efficiency of the estimated coefficients was enhanced by restricting coefficients to zero on variables that were not found significantly different from zero at the 0.05 level.

One transformation was made to two of the Danish electricity supply variables. From 2000-2015 hydropower in Denmark was almost negligible (see Table 17); however, rather than omitting this variable, a new variable DK RES was formed by adding together Danish hydropower and other Danish renewable energy sources. As discussed earlier, hydropower in comparison to other renewable energy sources such as wind and solar, has different characteristics, so while it does not contribute to greenhouse gases, its flexible ability to be dispatched when demand is high, explains the positive correlation with prices. Combining these two categories of renewable variables into one is a limitation to the study and future research is recommended to study these separately.

Over the last few years, the Nordic market has grown through market coupling with other countries outside of the Nordic region. Finland exchanges energy with Sweden and Estonia. Since, within the time frame of this study, Finland and Estonia have been trading since April 2010, an indicator variable was created to test the effect of Finland's trade with Estonia. The binary indicator was given the value of 1 to represent this coupling, starting in April 2010, and zero before that (Nord Pool, 2016b). In the system price model, a binary variable was constructed to test the effect of coupling markets with the Central Western European energy market it was given the value of 1 to represent the coupling, starting in January 2010, and zero before that (European Energy Exchange, 2014). Finally, a binary indicator was used to test the effect of Denmark coupling using planned energy exchanges from Germany (DE) and given the value of 1 to represent the coupling, starting in November 2009, and zero before that (Nord Pool, 2016c).

Before inserting any time-series electricity production variables into the models, each variable was tested for the presence of a unit root. To perform this an Augmented Dickey Fuller test (ADF) was used (Dickey and Fuller, 1979). To determine the appropriate number of lags in the ADF test, the approach suggested by Schwert (1989) was followed by using the equation $\mathrm{int}[12(n/100)^{1/4}]$, where n is the number of observations. In each ADF test, a linear deterministic time trend was included. The null hypothesis of ADF is that there is a unit root, and a test value lower than its critical ADF table value suggests that there is a unit root. The results, which are shown in Table 21, indicated that all the variables had a unit root. To handle this, the approach used by Gelabert et al. (2011), when analyzing daily Spanish electricity prices by taking the first difference for all variables, was used. After the first difference was taken for each variable, the ADF test was performed a second time, using the same number of lags. Furthermore, as Wooldridge (2010) discusses, taking the first difference removes the concern of a potential time-invariant endogenous relationship that may exist between the independent and dependent regressors.

Table 21 Augmented Dickey Fuller test statistics.

	ADF (in levels)	ADF (in first differences)
DK1 Price	-2.536	-5.014
FI Price	-2.938	-5.356
SP Price	-2.693	-5.482
DK Combustible Fuels	-2.311	-5.115
DK RES†	-1.241	-7.186
DK Gross Consumption	-4.979	-4.954
Finland Combustible Fuels	-3.132	-4.142
Finland Nuclear	-3.167	-7.04
Finland Hydro	-3.721	-4.228
Finland RES	5.070	-2.014
FI Gross Consumption	-2.258	-6.772
Norway Combustible Fuels	-2.126	-3.698
Norway Hydro	-4.260	-4.600
Norway RES	-0.734	-7.188
NO Gross Consumption	-3.399	-6.578
Sweden Combustible Fuels	-1.576	-5.177
Sweden Nuclear	-3.096	-5.390
Sweden Hydro	-3.038	-5.394
Sweden RES	3.792	-6.033
SE Gross Consumption	-3.191	-6.590

Notes: The reported statistics correspond to models that include a constant and 14 lags. A trend was included for both models. MacKinnon (1994) critical values for rejection of hypothesis of a unit root are -3.120 (10% confidence level), -3.410 (for 5% confidence level), and -3.960 (for 1% confidence level) A positive value indicates rejection of the null hypothesis. † The Danish hydropower and other renewable energy sources were combined to form one category.

Earlier studies (O'Mahoney and Denny, 2011; Tveten et al., 2013; Würzburg et al., 2013) have used robust linear regression models, meaning that the standard errors were estimated using the Huber-White sandwich estimators in order to handle minor problems about normality, heteroskedasticity, or some observations that exhibit large residuals, leverage or influence. To test whether a robust linear regression model was necessary, several diagnostics tests were run after each standard OLS regression. The Durbin-alternative test tests for serial correlation in the disturbances, but does not require that all the regressors be strictly exogenous (Durbin and Watson, 1950; Durbin, 1970). A Breusch-Pagen test was performed to test the assumption of homoskedastic residuals (Breusch and Pagen, 1979).

As Gelabert et al. (2011) discusses, one potential concern in the model specification is the correlation that may exist between the independent regressors. Hence, the variance inflation factor (VIF) was calculated for each model. A VIF greater than 10 suggests that multicollinearity is high (Craney et al., 2002; Kutner et al., 2004). As presented in the results (see Table 22), the system price model had the greatest mean VIF of 4.33. The final test performed was the Ramsey (1969) specification-test, which tested for omitted variables (see Table 22).

Table 22 Diagnostic regression results.

	Regressors	N	Durbin-alternative test	Breusch-Pagan/Cook-Weisberg test	Ramsey test	Mean VIF
	(excluding constant)		Pr.>χ^2	Pr.> χ^2	Pr.> χ^2	
SP	6	191	0.327	0.0004	0.004	4.33
DK	4	191	0.196	0.090	0.209	1.12
FI	8	191	0.496	0.306	0.601	2.27

The decision not to include importing and exporting volumes was intentional, so that the model would not suffer from endogeneity since the Nordic regions export and import with one another. It would also have led to double counting, since gross national production volumes were used rather than net volumes calculated by subtracting exports from gross production.

In each linear regression model, the unobserved error term, ε_t is assumed to be identically and independently distributed normally with 0 mean and variance σ^2.

5.5 Results and Discussion

Table 21 reports the ADF test results for the price, electricity supply variables, and national demand covariates. The findings showed that Norwegian hydropower was the only independent electricity production variable that permitted the rejection of the null hypothesis at the significance level of 99%, with the variable stationary without transformation into the first difference. However, once all dependent and independent variables were transformed by taking the first difference, only electrical production by Finnish renewable energy sources could not reject the null hypothesis at the 95% confidence level.

The results from the diagnostic tests are shown in Table 22. According to the results for the Ramsey (1969) test, the system price model suffered from omitted variables. Accepting this result, it was decided not to alter the system price model and acknowledge its possible shortcomings. This finding is important by showing that there may be a higher degree of difficulty when modelling the market clearing price versus area prices in the Nordic market. Given that the estimated coefficients could be biased in the system price model due to omitted variables, a marginal analysis was only conducted on the Danish and Finnish models.

Table 23 presents the estimation results for the three models: western Denmark (DK1); Finland (FI); and the Nordic market clearing price (SP). Comparatively, the range of explained variability across the three models according to the adjusted *R*-squared was in a similar range for Finland (0.47), and SP (0.43). However, in the case of western Denmark (DK1), only 29.3% of the variability was explained by the set of covariates.

Table 23 Linear regression results for sixteen-year analysis of the Nordic market clearing price (SP), western Denmark's (DK1) area price, and the Finnish (FI) area price.

	SP	DK1	FI
ΔDK Combustible Fuels		6.065*** (0.937)	
ΔDK RES†	-8.016*** (1.795)	-8.322*** (1.614)	
ΔFI Combustible Fuels	4.442*** (1.172)		4.980*** (0.975)
ΔFI Nuclear			-3.650* (1.756)
ΔFI Hydro			-6.950** (2.326)
ΔNO Hydro	-2.046*** (0.589)		
ΔSE Combustible Fuels			9.396*** (2.676)
ΔSE Nuclear	-2.312*** (0.591)	-1.809*** (0.442)	-2.576*** (0.489)
ΔSE Hydro	-3.766*** (0.617)	-1.626*** (0.456)	-1.449* (0.560)
ΔSE Demand	3.744*** (0.990)		
Spring			3.019** (1.098)
Summer			3.498*** (1.020)
Constant	-0.00142 (0.349)	-0.0139 (0.339)	-1.827** (0.560)
Observations	191	191	191
R-squared	0.434	0.293	0.470
Adjusted R-squared	0.416	0.278	0.446

* Indicates *p<0.05, **p<0.01, ***p<0.001. Standard error in parentheses. Year-specific indicator variables omitted for brevity. The symbol † is used to indicate that Denmark's electricity from hydropower was added to its other renewable energy source variable.

Exploring the signs of the different estimated coefficients that remained in the models, the results showed that when there was a one TWh increase in monthly generation using combustible fuels from any country this always led to a positive increase in the predicted marginal monthly spot prices. Furthermore, as shown in the Finnish model, where electricity produced from combustible fuels from both Finland and Sweden remained statistically significant at the 95% confidence level, the results showed that the average marginal effect for Sweden was two times larger (9.39 EUR/MWh) than for Finland (4.98 EUR/MWh). This result is logical because, over the sixteen years, Finland has almost always (98.98%) been a net importer. This finding also shows the magnitude in which different energy sources used for electricity production can impact its "connected" neighbors.

In this analysis, there were four energy sources represented, and while Denmark does not have any nuclear power plants, the estimated coefficients for Swedish hydroelectric energy (-1.63) and Swedish nuclear energy (-1.81) were significant at the 99% confidence level in the Danish model. Since there were four types of energy source variables, in the Danish model, all four are represented either by Denmark or another country Denmark exchanges energy with in the spot market.

Exploring the results more specifically, and employing the delta method (Rice, 1994), selected marginal changes were calculated. As mentioned, Sweden is expected to reduce its nuclear capacity by 2.7 GW by 2020. The expected impact of these nuclear power plant closures is mixed. Some experts predict that if these nuclear reactors go offline there will be a minimal impact (ICIS, 2015), while Energi Danmark, an energy trading company, has warned that the Nordic system price would increase somewhere between €1.0 – €4.0/MWh (ICIS, 2015).

To explore this further, Table 24 shows the marginal annual average change (EUR/MWh) in western Denmark and Finland’s spot price when there is a 1 TWh increase or decrease in Swedish nuclear energy per month. This corresponds to about half of the capacity (~1.35 GW) that is planned to go offline in 2020, assuming 100% uptime and usage.

As expected, there is an inverse relationship between production levels and prices. Nonetheless, whether there is an increase or decrease in production levels, Finland’s average annual spot prices experience larger changes than western Denmark’s price. For example, looking at 2002 in Table 24, holding all else constant, when Sweden decreased its nuclear energy by 1 TWh per month, the average annual spot price in Finland increased 6.19 EUR/MWh.

For western Denmark, the increase in the average annual price was roughly three times less (2.13 EUR/MWh). This finding supports Energi Danmark’s estimates (ICIS, 2015) and it goes further by showing that the effect of closure is not equal for all the countries. Furthermore, there were seven years (2000, 2003, 2004, 2005, 2011, 2013, and 2015) when the marginal effect created when Sweden increased its supply was greater than the marginal effect of its reducing nuclear power production for Finland and Denmark (see Table 24).

Overall, there was no obvious trend that emerged, although the absolute marginal difference was higher for Finland in the earlier years. There were four years (2005, 2006, 2013 and 2014), when the absolute marginal difference was almost the same for Finland and Denmark, showing that the absolute average marginal change in price will be roughly the same when there is either a 1 TWh increase in Swedish nuclear energy or a 1 TWh decrease in Swedish nuclear energy. Furthermore, the absolute difference in these years between Finland’s and Sweden’s differences was less than 0.50 EUR/MWh.

Table 24 The annual average marginal change in the Danish (DK1) and Finnish (FI) spot prices when there is a 1 TWh increase and decrease in Swedish nuclear energy (SE) production per month.

	FI					DK1				
	FI	-ΔSE Nuc.		+ ΔSE Nuc.		DK1	-ΔSE Nuc.		+ DSE Nuc.	
	Average Pr.	Marginal Δ	*t*-statistic	Marginal Δ	*t*-statistic	Average Pr.	Marginal Δ	*t*-statistic	Marginal Δ	*t*-statistic
	EUR/MWh					EUR/MWh				
2000	23.14	2.46	2.77	-4.74	-4.91	25.54	1.22	2.00	-1.86	-2.82
2001	33.54	4.87	5.12	-2.33	-2.57	34.83	2.06	3.19	-1.02	-1.64
2002	38.22	6.19	6.06	-1.01	-1.12	35.77	2.13	3.22	-0.95	-1.52
2003	48.24	1.59	1.77	-5.61	-5.65	45.76	0.88	1.42	-2.20	-3.40
2004	37.87	2.93	3.26	-4.27	-4.51	39.41	1.46	2.35	-1.62	-2.52
2005	40.00	3.56	3.87	-3.64	-3.93	48.95	1.33	2.16	-1.75	-2.72
2006	60.40	3.36	3.71	-3.84	-4.15	54.98	1.64	2.57	-1.44	-2.32
2007	37.26	4.37	4.68	-2.83	-3.12	39.88	2.00	3.20	-1.08	-1.69
2008	57.55	3.18	3.50	-4.02	-4.26	63.82	1.67	2.69	-1.41	-2.20
2009	42.35	4.85	5.05	-2.35	-2.59	41.62	1.26	2.03	-1.82	-2.86
2010	63.25	4.44	4.73	-2.76	-3.06	52.96	1.83	2.85	-1.25	-2.01
2011	51.54	1.25	1.42	-5.95	-5.89	50.04	0.35	0.56	-2.73	-4.12
2012	37.79	4.27	4.57	-2.93	-3.25	37.48	1.87	2.99	-1.21	-1.90
2013	42.48	3.25	3.59	-3.95	-4.17	39.15	1.26	1.93	-1.82	-2.90
2014	36.34	3.45	3.79	-3.75	-4.07	30.97	1.70	2.75	-1.38	-2.14
2015	29.68	2.77	3.05	-4.43	-4.67	22.94	1.02	1.61	-2.07	-3.26

All price series have been converted to real 2015 Euros.

Table 25 shows the effects of increasing or decreasing electricity generation from renewable energy sources in Denmark and Finland. In both the Danish and Finnish models, electricity produced from RES had an inverse relationship with price (Table 25), which supports earlier studies that have shown increased electricity generation from renewable energy sources, such as wind, will lead to a reduction in electricity market prices (Sensfuss et al., 2008; Würzburg et al., 2013). However, this effect may be transient due to increased interconnection (Ketterer, 2014), when policy is designed under incorrect assumptions (Nelson et al., 2015) or the structure of the wholesale market splits the electricity price into different products (Felder, 2011).

Table 25 The annual average marginal change in the Danish spot price when there is a 1 TWh increase or decrease in Danish RES energy per month and the annual average marginal change in the Finnish spot price when there is a 1 TWh increase and decrease in Finnish RES energy per month.

	DK1					FI				
	DK1	-ΔDK RES		+ ΔDK RES		FI	-ΔFI RES		+ ΔFI RES	
	Mean	Marginal Δ	*t*-statistic	Marginal Δ	*t*-statistic	Average Pr.	Marginal Δ	*t*-statistic	Marginal Δ	*t*-statistic
	EUR/MWh					EUR/MWh				
2000	25.54	7.96	4.24	-8.45	-4.57	23.14	7.33	1.97	-8.54	-2.38
2001	34.83	8.62	4.59	-7.79	-4.21	33.54	8.69	2.39	-7.19	-1.97
2002	35.77	8.85	4.75	-7.56	-4.04	38.22	10.27	2.87	-5.60	-1.50
2003	45.76	7.72	4.09	-8.69	-4.73	48.24	6.08	1.65	-9.79	-2.70
2004	39.41	8.08	4.28	-8.33	-4.53	37.87	7.58	2.04	-8.29	-2.31
2005	48.95	8.07	4.30	-8.34	-4.51	40.00	7.88	2.14	-7.99	-2.21
2006	54.98	8.53	4.57	-7.88	-4.24	60.40	7.96	2.18	-7.91	-2.17
2007	39.88	8.37	4.47	-8.04	-4.34	37.26	8.58	2.37	-7.29	-1.98
2008	63.82	8.48	4.55	-7.93	-4.25	57.55	8.18	2.20	-7.69	-2.14
2009	41.62	8.08	4.31	-8.33	-4.50	42.35	9.07	2.46	-6.80	-1.88
2010	52.96	8.39	4.45	-8.02	-4.36	63.25	8.36	2.30	-7.51	-2.05
2011	50.04	7.39	3.91	-9.02	-4.9	51.54	5.68	1.53	-10.19	-2.83
2012	37.48	8.30	4.41	-8.11	-4.4	37.79	8.42	2.3	-7.45	-2.05
2013	39.15	8.35	4.48	-8.06	-4.32	42.48	7.52	2.11	-8.35	-2.24
2014	30.97	8.23	4.38	-8.18	-4.43	36.34	7.85	2.13	-8.02	-2.22
2015	22.94	8.08	4.32	-8.33	-4.49	29.68	7.67	2.1	-8.20	-2.25

† The Danish hydropower and other renewable energy sources were combined to form one category. All prices have been converted to real 2015 Euros.

Another key result shown in both Table 24 and Table 25 is that the lowest marginal effect on the average annual price when there was a decrease in supply corresponds to 2011. Furthermore, this applied to Swedish nuclear energy, Danish renewable energy sources, and Finnish renewable energy sources. For example, as Table 25 shows, when there was a 1 TWh decrease in DK RES, the annual average marginal change in the Danish spot price, of 7.39 EUR/MWh. In the years after 2011, this value began to increase again. This result also applies to the Finnish model. Prior to 2011, when there was a 1 TWh decrease in Finnish nuclear energy, the annual average marginal change in the Finnish spot price was on average an increase in the Finnish spot price of around 8.18 EUR/MWh. In 2011, the marginal effect was almost 3 EUR/MWh less, but climbed again in 2012. In 2011 the Nordic market became fully interconnected with the Central Western European market (European Energy Exchange, 2014).

5.6 Conclusion

The integration of European electricity markets has long been viewed as an option to increase energy security by expanding the geographical boundaries of the transmission system and allowing more producers into the market. While earlier research had come to the overall conclusion that the benefits of market integration outweigh the cost of not integrating electricity markets (see, e.g., Hobbs et al., 2005; Küpper et al., 2009; Malaguzzi, 2009; Zani et al., 2010), it had also become apparent that unilateral decisions can have a rippling effect in an integrated market. More evidence of disconnect between regional and national policies may arise as the adoption of the United Nations Framework Convention on Climate Change Paris Agreement goes into effect, which sets the basis as: "Agreeing to uphold and promote regional and international cooperation in order to mobilize stronger and more ambitious climate action by all Parties and non-Party stakeholders, including civil society, the private sector, financial institutions, cities and other subnational authorities, local communities and indigenous peoples" (UNFCCC/COP21, 2015). Therefore, it will be pertinent for policy makers to make dynamic, regional policies to ensure that the same thing does not happen as occurred in Australia, for example, where fixed environmental targets muddled investments (Nelson et al., 2015).

While countries must coordinate to a higher degree, there needs to be more standardization in published data. An aim of this research was to perform a multinational study that evaluated market integration by specifically looking at how changes in the different types of fuels used to generate electricity can impact day-ahead prices for different countries, using accessible data. A primary benefit of using data from Nord Pool and the IEA was that the data covered a relatively lengthy period of 16 years (2000-2015).

This analysis showed that using the Nordic electricity supply variables, temporal indicators, gross consumption, and market integration variables was not enough to model the Nordic system price without the system price model suffering from omitted variables bias. However, for the Danish (DK1) and Finnish price models, these four categories of variables sufficed. In addition, this study confirmed the negative effect of increased generation from renewable energy sources on electricity prices. Cludius et al. (2014) showed that electricity prices in Germany were reduced between 6-10 EUR/MWh, and while Ketterer (2014) also found that increased wind power led to lower market electricity prices, prices began to exhibit more volatility (see also Riesz et al., 2016). While the marginal effect was not as large as the results of Cludius et al. (2014), Caralis et al. (2016) showed that the effect can vary due to project specific characteristics such as water depth, size of projects, distance from shore and grid availability.

While electricity produced from renewable energy sources costs less than electricity produced from conventional energy sources, the intermittency creates volatility and uncertainty in prices. As a result, this can skew the amount of capital required for investment in the transmission system, while also pushing out conventional thermal sources. Conventional sources continue to play a key role in mitigating the variability of intermittent renewable energy sources (Hittinger et al., 2010; Traber and Kemfert, 2011) until the issue of storability (outside of hydro reservoirs) is resolved. However, Gelabert et al. (2011) emphasized that the effect of low prices created by higher shares of renewable energy sources (RES) may be temporary, since this will slow investment, which in turn restricts supply. These findings are highly relevant, because in the analysis presented here, choices to increase wind power could impact investment decisions in Sweden, for example.

Another key lesson that emerged from this analysis is that not all changes were equal. This was shown by Swedish nuclear power, where it had a greater impact on Finland’s average marginal spot price than Denmark’s. Therefore, one might see in future years that, as market integration increases by increased transmission capacity across national borders, these effects will become larger because a nation may decrease its total capacity since it can either export or import electricity. In doing this, it places itself at the greater mercy of other nations’ energy targets and policies. Therefore, while interconnectivity can lead to a decrease in average spot prices, it also may make one nation more vulnerable to higher prices, especially in the case where the country is a net importer, such as Finland. We suggest that as long as markets become more integrated, it becomes more important to develop regional energy targets, shifting the power away from national actors. Acting independently will potentially diminish the benefits and strain international relationships.

6 The Relationship between Wind Energy on Cross-Border Electricity Pricing

This chapter contains a peer-reviewed journal article:

Unger, E. A., G. F. Ulfarsson, S. M. Gardarsson, and Th. Matthiasson, 2018: The effect of wind energy production on cross-border electricity pricing: The case of western Denmark in the Nord Pool market. *Economic Analysis and Policy*, 58:121–130. DOI: 10.1016/j.eap.2018.01.006

6.1 Introduction

A key requirement for the electricity transmission system is that it remains in balance between the supply and the demand. Highly variable energy sources can make finding this balance more complex. This is occurring as the share of renewables, particularly wind energy, increases. This is the case in northern Europe and mix into this the potential phase-out of nuclear power in Germany and Sweden. To keep the balance, a country that produces either too little or too much electricity for domestic consumption may either import or export electricity to neighboring countries. For example, in 2006, Denmark's net exports were 6,936 gigawatt hours (GWh) to Norway, Sweden, and Germany, but starting in 2008 until 2016, Denmark began importing more energy than it exported, with the largest percentage coming from Norway (Danish Energy Agency, 2017). In 2016, total net imports were 5,057 GWh (Danish Energy Agency, 2017).

Wind energy used to produce electricity in Denmark has grown substantially over the last decade. In 2006, total electricity production in Denmark was roughly 45,451 GWh (Danish Energy Agency, 2017). Of this value, 13% (6,108 GWh) was from wind energy (Danish Energy Agency, 2017). In 2016, wind energy's share of total electricity production reached 42% (Danish Energy Agency, 2017).

As the integration of wind energy in Denmark has increased over the years, so has the number of strategies dealing with the unpredictable and variable nature of wind. At a national level, Denmark supplies roughly half of its electricity from small combined-heat-and-power (CHP) plants (Danish Energy Agency, 2017). The advantage of this is that the heat-supply network is tied to large water tanks for thermal energy storage, which provides flexibility, allowing for varying proportions of heat and electricity in response to changes in wind output (Østergaard, 2010). Improvements in weather forecasting have also helped Denmark successfully integrate higher shares of wind produced electricity (Martinot, 2015).

Internationally, another key innovation used to respond to variations in electricity supply has been the creation of a common electricity market where energy can be either bought or sold across national borders (Directive 96/92/EC; Directive 2003/54/EC). To participate in the market, each country must first be physically connected to other national transmission systems via high voltage direct current (HVDC) interconnectors (Nord Pool, 2017e). The questions of when, how much energy, and from whom, depend on factors such as available transmission capacity on the HVDC interconnectors and availability of supply. Unger et al. (2017) showed how unilateral decisions at the national level regarding reductions in selected energy sources used for electricity generation can greatly impact market prices across national borders in the Nordic region.

Watcharejyothin and Shrestha (2009), Denny et al. (2010), and Doorman and Frøystad (2013) have all concluded that increased interconnection can facilitate the integration of intermittent renewable energy sources, but that there must be enough transmission capacity available to allow energy to flow to areas where needed. This too has been recognized by the European Council. Europe’s initial target of capacity on interconnections being 10% of the installed electricity production capacity has come under further evaluation, with the European Council requesting that this target be increased to 15% by 2030 (COM, 2015). In 2014, there were still many European Union members operating below the 10% interconnection target. These include, Spain (3%), Estonia (4%), and several others (COM, 2015). In contrast, Denmark is almost four and a half times higher. In 2014, its interconnection level was 44% (COM, 2015).

6.2 Nord Pool Day-Ahead Operations

The planned cross-border energy that flows across HVDC interconnectors in the Nordic day-ahead market, Nord Pool, is used in price settlement with the aim of either eliminating price differences between areas or at least reducing the price difference (Nord Pool, 2017e). Once all bids and offers have been received, a market clearing price (also known as the system price) that assumes no physical constraints on the transmission system is calculated (Nord Pool, 2017e). However, during some trading hours, there may be locations on the grid where there is not enough transmission capacity to support the power needed to meet energy demand.

Bids and offers are submitted to the market but attached to an area to which they belong. These geographical areas are defined by the transmission system operators, and in the Nordic region there are twelve: Five in Norway; four in Sweden; one in Finland; and two in Denmark. Like the market clearing price, based on the bids and offers for each area, the supply and demand curves form the equilibrium price for each area (Nord Pool, 2017e). Given the different levels of demand and available supply, there can be price differences between areas. The interconnection mechanism between areas and different markets works so that the transmission system operators, those who oversee operating and controlling HVDC interconnectors (Nord Pool, 2017e), decide on a specific volume of energy that may flow unilaterally across borders in a particular hour. The intended effect of these exchanges is that by either increasing or decreasing the supply in different areas, this will eliminate or decrease price differences between areas, allowing the planned cross-border energy exchange to reduce the risk of arbitrage and increase transparency (Weber et al., 2010), while leading to price convergence between areas since these volumes are used in price settlement (Meeus et al., 2009).

While these interconnections serve the purpose of creating more price stability in market prices, consequently, until the new EU target of 15% is reached, the increased penetration of intermittent renewable energy sources is potentially a force working against price convergence (Gianfreda et al., 2016). This is due to wind energy's ability drive prices almost to zero or even negative, which occurs in periods when demand is low and supply is very high. There are therefore three possible pricing scenarios that exist between any two areas (higher price in area A-lower price in area B, lower price in area A-higher price in area B, or equal price in both areas).

In this paper, the Nord Pool area of western Denmark, one of two Nord Pool areas in Denmark, has been selected as the primary focus, since it has a higher share of wind generation compared to the Nord Pool area of eastern Denmark and other Nord Pool areas. Within the Nord Pool day-ahead market, there is planned cross-border energy flow between western Denmark and eastern Denmark, southern Norway, Stockholm, Sweden, along with Germany. Each area has their own unique electricity generation mix. On average, Denmark imports more energy from Norway compared to Sweden and Germany. This most likely can be explained by Norway's high share of hydropower (97%), the flexible dispatch nature of hydropower (Hirth, 2016) and its ability to compliment the variability of wind (Jaramillo et al., 2004). This could potentially change if Norway were to experience heatwaves and droughts such as what occurred in 2003 (Fink et al., 2004), although by being connected to other energy systems, the level of diversification can increase energy security and reduce risk when these types of events arise.

This study estimates the effect of western Denmark's wind energy production levels and planned cross-border energy flow on interconnectors between western Denmark and the trading partners of eastern Denmark, southern Norway, Stockholm, Sweden, and Germany, on the three price scenarios. In other words, the research question is: Do wind energy and energy flow on interconnectors lead to western Denmark tending to have a higher or lower or equal price than its Nordic Nord Pool trading partners?

This is investigated by employing a multinomial logit model. Multinomial logit models (MNL) are a common form of probability models that allow researchers to estimate the effect of different regressors on a set of discrete alternatives. While MNL has been used in the field of energy (Heltberg, 2004) before, it has not been used in the context as presented here.

6.3 Data and Methods

The analysis uses hourly market data from the Nord Pool market for the years 2012 through 2015 (Nord Pool, 2016a). Four price series (EUR/MWh) from Nord Pool were selected: 1) western Denmark (DK1), 2) eastern Denmark (DK2), 3) southern Norway (NO2), and 4) Stockholm, Sweden (SE3). These abbreviations, DK1, DK2, NO2, SE3, are used by Nord Pool and will be used throughout the rest of this paper to refer to these areas.

These price series were used to construct a multinomial dependent variable for the three price scenarios that can exist between DK1 and each of its Nordic trading partners. Three such dependent variables were created, using the price differences between DK1 and each one of its Nordic trading partners (DK2, NO2, and SE3). For example, eastern Denmark's

(DK2) price was subtracted from western Denmark's (DK1). If the difference was positive, this was indicated as the first pricing outcome: where DK1 has a higher price than DK2 in hour *h* even after the planned cross-border energy flow between the two areas has occurred. If the difference was negative, this was indicated as the second pricing outcome when in hour *h*, DK1's price was lower than DK2's. The third outcome was set when prices were equal (i.e., the price difference was zero) between DK1 and DK2. This was repeated for NO2 and SE3.

Table 26 presents the three pricing outcome variables for the three sets of trading partners tabulated across the four years (2012-2015) under study. Table 26 shows that DK1-DK2 had the highest share of equal prices compared to DK1-NO2 and DK1-SE3, when in 2012, prices were equal between DK1 and DK2 86.3% of the time. This percentage fell by 15% in 2013, and remained around 70.8% for 2013 and 2014. While the frequency of equal prices between DK1 and DK2 fell, the frequency of equal prices increased for the other two sets of partners. In 2012, the share of equal prices compared to the other pricing outcomes for DK1 and NO2 was 44.7%, and by 2015, this figure had increased to 60.8%. Whereas overall there were more equal prices between DK1-SE3 (57.4%) than there were between DK1-NO2, the share of equal prices for DK1-SE3 did not increase from 2012 to 2015 by the same percentage points (16.2%) as they did for DK1-NO2.

Table 26 The number of hours across years when western Denmark's (DK1) price was higher, lower or equal to its DK2, NO2, and SE3 trading partners' price.

	2012	2013	2014	2015	2012	2013	2014	2015
	N				Column %			
DK1-DK2								
DK1 Higher Price (N=677)	219	230	128	100	2.5	2.7	1.5	1.5
DK1 Lower Price (N=7,242)	983	2,296	2,349	1,614	11.2	26.5	26.8	24.6
Equal Price (N=24,812)	7,557	6,137	6,281	4,837	86.3	70.8	71.7	73.8
Total (N=32,731)	8,759	8,663	8,758	6,551				
DK1-NO2								
DK1 Higher Price (N=13,489)	4,362	2,654	4,408	2,065	49.9	30.6	50.3	31.5
DK1 Lower Price (N=4,898)	470	2,612	1,313	503	5.4	30.2	15.0	7.7
Equal (N=14,320)	3,903	3,397	3,037	3,983	44.7	39.2	34.7	60.8
Total (N=32,707)	8,735	8,663	8,758	6,551				
DK1-SE3								
DK1 Higher Price (N=6,726)	3,239	997	1,295	1,195	37.1	11.5	14.8	18.2
DK1 Lower Price (N=7,237)	673	2,696	2,698	1,170	7.7	31.1	30.8	17.9
Equal (N=18,743)	4,823	4,969	4,765	4,186	55.2	57.4	54.4	63.9
Total (N=32,706)	8,735	8,662	8,758	6,551				

Because there are three possible pricing outcomes between western Denmark and its trading partners; DK1's price is higher, lower, or equal; this leads to the development of a discrete probability model. In this study, the independent categorical pricing variable is at the hourly level. The probability that an area in hour *h* has pricing outcome i is written

$$P_{hi} = P(O_{hi} \geq O_{hi'}),\ \forall i' \in I, i' \neq\ i, \tag{2}$$

where O_{hi} is the unobserved propensity of the pricing outcome *i* that western Denmark will have in hour h with one trading partner, where the i is drawn from a set of I possible pricing outcomes (here the three outcomes: higher in DK1, lower in DK1, and equal prices). Assuming that O_{hi} has a linear-in-parameters form, it may be expressed

$$O_{hi} = \boldsymbol{\beta}_i \mathbf{x}_h + \varepsilon_{hi}, \tag{3}$$

where $\boldsymbol{\beta}_i$ is a vector of estimable coefficients for pricing outcome *i* and $\mathbf{x}_h$ is a vector of exogenous variables that significantly influence price differences in hour *h*. ε_{hi} is a random component (an error term) that captures unobserved influences. Given the assumption that ε_{hi} is identically and independently distributed with a type 1 extreme value distribution, and the assumption that the bidding area will experience the pricing outcome *i* that has the highest propensity this leads to the multinomial logit model (McFadden, 1981):

$$P_{hi} = \frac{e^{\boldsymbol{\beta}_i \mathbf{x}_h}}{\sum_{j=1}^{I} e^{\boldsymbol{\beta}_j \mathbf{x}_h}}. \tag{4}$$

The coefficients, $\boldsymbol{\beta}_i$, are estimated with the method of maximum likelihood. Three models were developed, for DK1-DK2, DK1-NO2, DK1-SE3. To develop the models, all identified explanatory variables were inserted and tested in the models. To improve statistical efficiency, only coefficients that were statistically significantly different from zero at the 0.05 level of significance were kept in the final results, less significant coefficients were constrained to zero. Without loss of generality the coefficients for one pricing outcome need to be set to zero and that outcome becomes the base case. In this work the equal prices outcome is selected as the base case and equations are estimated for the higher and lower prices.

To identify explanatory variables influencing the pricing outcomes in the models, we first consider that equilibrium area prices are always determined by the aggregate supply and demand curves for each area. Furthermore, day-ahead prices are based on predicted levels of production and consumption. Therefore, in each model, the explanatory variables may be categorized into two main categories: predicted production (i.e., supply) and predicted consumption (i.e., demand).

To test the effect of western Denmark's different wind levels on the three pricing outcome scenarios, the approach used by Jónsson et al. (2010) was applied. Jónsson et al. (2010) agreed with Karakatsani and Bunn (2008) that fuel prices and weather conditions affect the supply function indirectly and in a highly non-linear fashion. To handle this issue, Jónsson et al. (2010) used a method that more directly linked these types of variables to the supply function, by creating a wind share variable that divided predicted wind levels into predicted production levels. Here, that same method was applied using western Denmark's observed total production[1] in hour h divided by western Denmark's predicted next-day wind energy supply in hour h. This generated a wind share variable, which was used to create three predicted wind share binary variables, for high, medium, and low wind energy supply. The lowest predicted wind share level was defined as 1 if the contribution of wind energy to production was less than 33% and zero otherwise. The medium predicted wind share level was defined as 1 when the wind share was from 33% and up to 66%. It should be noted that the medium level variable was omitted from all three models to prevent perfect multicollinearity with the low and high wind level variables. The highest predicted wind share level was defined as 1 in hours when the share of wind was 67-100% and 0 otherwise.

Table 27 presents the number of hours when electricity was generated by wind energy in western Denmark at the three predicted wind share levels. Examining the highest predicted wind share category (67-100%), from 2012 to 2015, the percentage of times when the wind share was at this level increased from 13.0% to 31.6%. The lowest wind share category (<33%) fell from 47.8% in 2012 to 26.9% in 2015.

Table 27 Western Denmark's number of hours per year at high, medium and low levels of wind energy.

		2012	2013	2014	2015	2012	2013	2014	2015
	N Total	N				Col.%			
Predicted wind share <33%	14,145	4,187	4,602	3,593	1,763	47.8	53.1	41.0	26.9
Predicted wind share 33-66%	12,938	3,410	3,215	3,843	2,470	38.9	37.1	43.9	37.7
Predicted wind share 67-100%	5,329	1,137	825	1,294	2,073	13.0	9.5	14.8	31.6
Total	32,731	8,759	8,663	8,758	6,551*	100.0	100.0	100.0	100.0

* In October 2015, Nord Pool changed its definition of predicted wind production being a share of total predicted production. After this period, to calculate total predicted production, predicted wind production must be added to predicted total production. To handle this data discrepancy, October, November, and December in 2015, were omitted from the data set.

Nord Pool defines planned cross-border energy flow as a share of total production for each area and given that the planned cross-border energy flow occurs before the price is settled in each area, it is assumed that these variables are strictly independent of one another. To avoid a double count of production levels, planned cross-border energy flow variables that were directly related to the set of trading partners were omitted from the model due to endogeneity. For example, if the MNL model was based on the pricing outcomes between DK1 and NO2, then the planned cross-border energy flow across DK1-NO2 HVDC interconnector was omitted, while the energy flow across the other HVDC interconnectors was included. The average planned cross-border energy flow levels between the partners are presented in Table 28.

[1] Until October 2015, Nord Pool defined predicted wind levels as a share of total predicted production; therefore, their quotient should not exceed one. Despite this definition and prior to October 2015, there exist hours in the Nord Pool database when this quotient exceeded one. To avoid this data artifact, observed total production was used in lieu of total predicted production.

Also presented in Table 28 are the four consumption variables that correspond to the total demand for each area (DK1, DK2, NO2, and SE3). Nord Pool publishes hourly predicted consumption for DK1 and DK2, while it publishes predicted consumption at the national level only for Norway and Sweden. Nord Pool does publish observed consumption levels for NO2 and SE3, so it was decided to use these variables in lieu of predicted consumption for NO2 and SE3.

Table 28 Descriptive statistics for area consumption and planned cross-border energy flow.

	N	Median	Mean	Std. Dev.	Min.	Max.
			MWh			
Planned flow from DK1 to DK2	32,707	338.3	311.9	250.2	0	590
Planned flow from DK2 to DK1	32,707	0.0	11.5	56.6	0	600
Planned flow from DK1 to NO2	32,731	0.0	188.2	370.8	0	1632
Planned flow from NO2 to DK1	32,731	550.0	513.7	470.7	0	1532
Planned flow from DK1 to SE3	32,707	0.0	169.2	242.5	0	740
Planned flow from SE3 to DK1	32,707	0.0	168.0	262.0	0	680
Planned flow from DK1 to DE	32,731	123.1	208.4	391.0	0	1500
Planned flow from DE to DK1	32,731	0.0	331.0	416.2	0	1780
Predicted consumption for DK1	32,731	2,216.0	2,271.3	490.7	1184	3,687
Predicted consumption for DK2	32,731	1,512.0	1,519.3	329.6	725	2,545
Observed consumption for NO2*	32,707	3,790.0	3,897.9	744.6	2327	6,702
Observed consumption for SE3*	32,706	9,632.0	9,820.7	2,228.9	5057	17,466

Finally, to account for the temporal trends that occur in electricity prices, fixed effects at different time scales were created to control for annual, seasonal, daily and intraday correlation. An hourly indicator variable was used to control for the differences in demand that occur daily in peak and off-peak periods. The peak period is defined by Nord Pool as 8 am – 8 pm (Nord Pool, 2016a). The peak-period fixed effect is defined as 1 in the peak hours and 0 otherwise. Fixed effects were also created for each season defined as: winter (December, January, and February), spring (March, April, and May), summer (June, July, and August), and fall (September, October, and November). Fall was omitted from the models to avoid perfect multicollinearity with the other seasons. Finally, fixed effects were created for each year of analysis, omitting 2013 to prevent perfect multicollinearity.

In the case of three or more alternatives in a MNL model, the direct interpretation of the sign of coefficients as either increasing or decreasing the probability of an outcome can yield misleading results about the effect of a variable on the probability of a pricing outcome. A negative (positive) coefficient on a variable in a pricing outcome cannot be freely interpreted as decreasing (increasing) the probability of that pricing outcome. This is due to the fact that the rate of change in probability is not a simple linear function of the coefficient in that pricing outcome, but is also a function of its effect and the effects of all the other coefficients in all other pricing outcomes (Greene, 2003). Observing a negative coefficient and claiming this indicates the variable decreases the probability can therefore be wrong.

This problem may be avoided by exploring the marginal effects of each variable on the probability using elasticity, defined in a standard way and derived from (4):

$$E_{x_{hk}}^{P_{hi}} = \frac{\partial P_{hi}}{\partial x_{hk}} \frac{x_{hk}}{P_{hi}} = \left(\beta_{ik} - \sum_{j=1}^{I} \beta_{jk} P_{hj}\right) x_{hk}, \tag{5}$$

which yields the direct elasticity of the probability with respect to a change in the k-th variable, x_{hk}, and accounting for that it can enter one or more equations. The interpretation is a percentage change in probability per percentage change in a variable. Values that exceed 1 represent a large, elastic effect between the independent regressor and pricing outcome. For binary indicator variables, it is not possible to calculate the elasticity since then (4) is not differentiable by the variable, which only takes on the values 0 and 1. Instead, we calculate the percentage change in probability when each binary indicator variable is switched either 0-1 or 1-0. This has been termed the pseudo-elasticity and was applied, e.g., by Shankar and Mannering (1996) and Ulfarsson and Mannering (2004). Writing this out yields:

$$E_{x_{hk}}^{P_{hi}} = \frac{P_{hi}[\text{given } x_{hk} = 1] - P_{hi}[\text{given } x_{hk} = 0]}{P_{hi}[\text{given } x_{hk} = 0]}, \tag{6}$$

which is called the direct pseudo-elasticity of the probability and captures the percentage change in probability when the k-th variable from the vector $\mathbf{x}_h$ in hour h is switched (0-1, 1-0). Because the elasticity and pseudo-elasticity are point values, holding for each observation h, each elasticity and pseudo-elasticity is aggregated by taking the average value for all observations. For pseudo-elasticities, they are then multiplied by 100 to represent the value in percent. In this way the sign of the pricing outcome can be interpreted as increasing (positive) or decreasing (negative).

6.4 Results

Three multinomial logit models are presented in Table 29 showing the estimated effects of the explanatory variables on the pricing outcome between western Denmark (DK1) and its Nordic partners: 1) eastern Denmark (DK2); 2) southern Norway (NO2); and 3) Stockholm, Sweden (SE3). Table 30 presents the average direct elasticities for the continuous explanatory variables and Table 31 presents the average direct pseudo-elasticities for the binary indicator variables. Contrary to the estimated coefficients for which at least one outcome must be restricted to zero, the average direct elasticities and average direct pseudo-elasticities can be calculated for all outcomes.

Overall the results show that there are large differences in the size of the direct elasticity and pseudo-elasticity effect for many variables across the three models, however, often the signs are the same in the three models.

The signs of the calculated pseudo-elasticity for the predicted wind share variables (wind share < 33% and wind share 67-100%) were intuitively correct in all three models with low wind share in DK1 tending to increase the probability of higher price in DK1 and high wind share tending to increase the probability of lower price in DK1. This effect was smallest between western Denmark and eastern Denmark (DK1-DK2). The effect of different predicted wind levels on the pricing outcomes between DK1-NO2 and DK1-SE3 were much larger. Shown in Table 31, when wind energy in western Denmark is less than 33% of its total electricity production, on average there was a 253% increase in the probability of DK1 having a higher price than southern Norway, a 78.2% decrease in the probability of DK1's area price being lower, and a 16.8% decrease in the probability of the prices being equal between DK1 and NO2.

The average increase in probability of DK1 having a higher price than SE3 was 359.8%, while in the DK1-NO2 model this percentage change is 253.0%. When the predicted wind share was 67-100%, the highest percentage change corresponded to DK1-NO2, where the average increase in probability of DK1 having a lower price than NO2 was 517.1%. Respectively, the average percentage change in probability of lower price was 121.8% between DK1 and SE3.

Overall, the elasticity values corresponding to planned cross-border energy flow shown in Table 30 appear small for planned cross-border energy flow variables, however, elasticity values larger than 0.1 in absolute value do, in this case, still have a large effect on the probability because the variation in the flow is large, on the order of 100%, as shown by the standard deviations on the flow variables in Table 28, and even greater if the mean is compared with the maximum value. This result differs from Higgs et al. (2015) who found that Australian interregional flows did not significantly affect prices or price volatility.

When DK1 exported 1% more energy to NO2, the average probability of DK1 having a higher price than DK2 increased 0.22%. When the energy flow was reversed and energy entering DK1 from NO2 increased by 1%, the average probability of DK1 having a higher price than DK2 fell (-0.32%). Interestingly, when DK1 exported 1% more energy to Germany (DE), the average probability of DK1 having a lower price than NO2 fell 1.63% and respectively for SE3 it fell 1.33%. The results also showed that when DK1 exported 1% more energy to DK2, that the average probability of there being equal prices between DK1-SE3 fell 0.29%. There was only one planned cross-border trade variable, whose calculated average elasticity was greater than 1%. When there was a 1% increase in the total volume of energy exported from western Denmark to Germany, this decreased the average probability of DK1's price being lower than NO2's price by 1.63%. Respectively, between DK1-SE3, the probability of DK1's price being lower than SE3's price fell 1.33%.

While electricity supply was represented by two types of variables (wind and planned cross-border energy flow), consumption was represented directly as itself. The results in Table 30 show that the effect on the pricing outcomes between DK1 and DK2 is much larger when there is a 1% increase in predicted consumption for DK2 versus a 1% increase in predicted consumption for DK1. In this case, the average probability of DK1 having a lower price than DK2 increased 1.43%. In contrast, the different pricing outcomes for NO2 and SE3 were highly sensitive. For example, if there was a 1% increase in DK1's predicted consumption, the average probability of DK1 having a lower price than NO2 fell 6.10%. If consumption in NO2 increased 1%, the average probability of NO2 having a higher price (i.e., DK1's price is lower) increases 7.45%.

Four levels of fixed effect temporal indicators were included in each model. Overall, the fixed effect of each year (2012, 2014, and 2015) was found to be small, although there were a few exceptions. In 2012, there was a 291.1% increase in probability that DK1 would have a higher price than SE3 (Table 31) compared to 2013, with everything else kept constant. In 2014, this corresponding value fell to 9.5% and increased again to 197.5% in 2015. Comparing these results to the DK1-NO2 model, while the direction of the signs was the same, the size of the effect was the reversed. In 2012, the average probability of DK1 having a higher price than NO2 increased by 31.3%. However, in 2014, respectively, this value jumped to 123.2%, and fell to 70.5% in 2015. This shows there is significant annual variation and supports the need for including fixed effects for the years.

The pseudo-elasticities calculated for the seasons in Table 31 do in some cases show seasonal changes in demand patterns. For example, when it is winter, the average probability of DK1 having a higher price than NO2 decreases -7.1% compared to fall. In spring this percentage shows an increase of 2.2% and drops slightly to 1.5% in summer, compared to fall. In terms of average production and average consumption in DK1 in winter and spring there is an inverse relationship. In winter, respectively, the average production and consumption levels for DK1 are 3,219 MWh and 2,542 MWh. In summer, DK1's production is less (1,703 MWh) than its average consumption (2,082 MWh). However, in other cases, it does not, which may reflect the influence of other regressors in the model.

At the shorter temporal levels (daily and hourly) there were more variables that were shown to have a larger effect on the pricing outcomes than the seasonal and yearly indicator variables. The pseudo-elasticities shown in Table 31, show that every daily indicator variable, except for Friday (Saturday was omitted to prevent perfect multicollinearity), and the peak time indicator variable, defined as 8 am – 8 pm, had an effect on the outcome of DK1 having a higher price than DK2. In comparison to the other two models, DK1-NO2 and DK1-SE3, the size of the effect from these temporal indicator variables was much smaller suggesting lesser short-term variation in the probabilities of the international energy trade pricing scenarios compared to the domestic DK1-DK2 trade.

Table 29 Multinomial logit pricing outcome models for electricity trade between western Denmark and selected partners.

	DK1-DK2		DK1-NO2		DK1-SE3	
	Higher Price	Lower Price	Higher Price	Lower Price	Higher Price	Lower Pr.
	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.
Constant	-2.1592***	-3.3886***	0.7242***	-1.0536***	-2.7811***	-2.3302***
Predicted wind share <33%	0.5189***	-0.6407***	1.4453***	-1.3383***	1.4777***	-1.1044***
Predicted wind share 67-100%	-0.2738*	0.2825***	-0.7693***	1.6839***	-0.9540***	0.7557***
Planned flow from DK1 to DK2	---	---	-0.0006***	-0.0003**	-0.0006***	0.0029***
Planned flow from DK2 to DK1	---	---	0.0011***	0.0031***	0.0041***	-0.0104***
Planned flow from DK1 to NO2	0.0014***	0.0004***	---	---	0.0021***	0.0011***
Planned flow from NO2 to DK1	-0.0005***	0.0005***	---	---	-0.0002***	0.0004***
Planned flow from DK1 to SE3	0.0009***	0.0021***	0.0010***		---	---
Planned flow from SE3 to DK1	-0.0007***		0.0014***	0.0026***	---	---
Planned flow from DK1 to DE	0.0005***	-0.0014***	0.0007***	-0.0046***	0.0014***	-0.0036***
Planned flow from DE to DK1	-0.0012***	0.0006***	-0.0014***	0.0015***	-0.0026***	0.0005***
Predicted Consumption for DK1		0.0004**	0.0036***	-0.0013***	0.0029***	
Predicted Consumption for DK2	-0.0020***	0.0012***	†	†	†	†
Observed Consumption for NO2†	†	†	-0.0026***	0.0010***	†	†
Observed Consumption for SE3†	†	†	†	†	-0.0007***	0.0002***

(*Continued*)

Table 29 (Continued) Multinomial logit pricing outcome models for electricity trade between western Denmark and selected partners.

	DK1-DK2 Higher Price Est. Coeff.	Lower Price Est. Coeff.	DK1-NO2 Higher Price Est. Coeff.	Lower Price Est. Coeff.	DK1-SE3 Higher Price Est. Coeff.	Lower Pr. Est. Coeff.
2012		-0.4865***	-0.1150**	-2.1096***	1.3984***	-0.9374***
2014	-0.4656***	-0.1365**	0.8766***	-1.1944***	0.1145*	
2015	-0.3490**	-0.1207*		-2.9135***	0.9116***	-1.4009***
Winter	0.5472***	-0.7888***		0.5258***	-0.4741***	-0.5327***
Spring		-1.1755***		-0.1430*	-0.1123*	-1.4079***
Summer		-0.8215***	-0.3917***	-1.6997***	0.1206*	-1.2694***
Sun.	0.7539***	-0.1256*		-0.1874**	0.2440***	-0.3003***
Mon.	1.0110***		-0.1802***			
Tues.	0.9364***	-0.1755***	-0.2074***	-0.3357***		-0.1940**
Wed.	0.9910***	-0.2052***			0.1817***	-0.1935***
Thur.	0.8954***	-0.1476**				-0.1505**
Fri.	0.6611***	-0.0996*			-0.1063*	
Peak time (08:00 -20:00)	1.1035***			-0.5196***	0.2533***	
Log-likelihood at zero	-20,422.50		-33,074.88		-31,988.58	
Log-likelihood at convergence	-16,558.11		-19,740.11		-20,548.37	
ρ^2	0.1899		0.4143		0.3670	
Number of observations	32,731		32,707		32,706	

* p<0.05, ** p<0.01 *** p<0.001. †Nord Pool does not publish individual predicted consumption for NO2 and SE3, however, for observed consumption it does. In this study, the observed values for NO2 and SE3 have been used as a substitute for predicted values. The symbol --- is used to indicate variables that were omitted from the model due to endogeneity. † indicates that it was omitted due to irrelevance in the equation. Equal price is the base case in each model

Table 30 Average direct elasticities showing the percentage change in probability per percentage change in area consumption and planned cross-border energy flow variables.

	DK1-DK2			DK1-NO2			DK1-SE3		
	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.
Planned flow from DK1 to DK2	---	---	---	-0.12	-0.02	0.08	-0.48	0.62	-0.29
Planned flow from DK2 to DK1	---	---	---	0.002	0.02	-0.01	0.02	-0.15	-0.03
Planned flow from DK1 to NO2	0.22	0.04	-0.04	---	---	---	0.26	0.08	-0.14
Planned flow from NO2 to DK1	-0.32	0.23	-0.04	---	---	---	-0.10	0.21	0.02
Planned flow from DK1 to SE3	-0.01	0.20	-0.16	0.12	-0.04	-0.04	---	---	---
Planned flow from SE3 to DK1	-0.12	0.002	0.002	0.06	0.25	-0.18	---	---	---
Planned flow from DK1 to DE	0.19	-0.43	0.04	0.12	-1.63	-0.11	0.33	-1.33	-0.13
Planned flow from DE to DK1	-0.29	0.08	-0.04	-0.38	0.23	-0.09	-0.60	0.07	-0.04
Predicted Consumption for DK1	-0.19	0.63	-0.19	5.05	-6.10	-3.24	5.26	-1.43	-1.43
Predicted Consumption for DK2	-3.45	1.43	-0.36	†	†	†	†	†	†
Observed Consumption for NO2✝	†	†	†	-6.74	7.45	3.47	†	†	†
Observed Consumption for SE3✝	†	†	†	†	†	†	-6.05	2.61	1.08

✝Nord Pool does not publish individual predicted consumption for NO2 and SE3, however, for observed consumption it does. In this study, the observed values for NO2 and SE3 have been used as a substitute for predicted values. The symbol --- is used to indicate variables that were omitted from the model due to endogeneity. † indicates that it was omitted due to irrelevance in the equation. Variables with elasticity greater than 0.1 are shaded light gray, and those with elasticity greater than 1 are shaded darker gray.

Table 31 Average direct-pseudo elasticities that show the percentage change when each binary variable is switched from 0 to 1 across the three pricing outcome models.

	DK1-DK2			DK1-NO2			DK1-SE3		
	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.
Predicted wind share <33%	91.2	-40.0	13.8	253.0	-78.2	-16.8	359.8	-65.2	4.9
Predicted wind share 67-100%	-28.3	25.0	-5.7	-46.8	517.1	14.6	-59.9	121.8	4.2
2012	10.7	-31.9	10.7	31.3	-82.1	47.3	291.1	-62.2	-3.4
2014	-34.7	-9.3	3.9	123.2	-71.9	-7.1	9.5	-2.3	-2.3
2015	-27.1	-8.4	3.4	70.5	-90.7	70.5	197.5	-70.5	19.5
Winter	102.7	-46.7	17.3	-7.1	57.1	-7.1	-23.2	-27.5	23.5
Spring	27.6	-60.6	27.6	2.2	-11.4	2.2	27.4	-65.1	42.5
Summer	18.9	-47.7	18.9	1.5	-72.6	50.2	47.8	-63.2	31.0
Sun.	113.9	-11.2	0.7	2.9	-14.7	2.9	30.0	-24.6	1.9
Mon.	166.4	-3.1	-3.1	-10.0	7.7	7.7			
Tues.	157.4	-15.3	0.9	-7.1	-18.3	14.3	4.4	-14.0	4.4
Wed.	173.0	-17.5	1.3				20.7	-17.1	0.6
Thur.	146.1	-13.3	0.5				3.4	-11.1	3.4
Fri.	94.4	-9.1	0.4				-8.1	2.2	2.2
Peak time (07:00-19:00)	193.8	-2.5	-2.5	8.9	-35.2	8.9	22.6	-4.8	-4.8

Shading indicates a percentage change greater than 100%.

6.5 Conclusion

The main purpose of this paper was to estimate the effect of different predicted wind levels and planned cross-border energy flow on the probability of different pricing outcomes between western Denmark and its three Nordic trading partners (eastern Denmark, southern Norway, Stockholm in Sweden). While the results in this analysis do not estimate a specific value by which the prices change, it does support earlier research such as Jónsson et al. (2010) and Gelabert et al. (2011) to show the large, negative association between increased levels of wind energy and market prices. In addition, this analysis showed differences in price sensitivity for the different Nordic trading partners.

An overreaching result was that both of the key variable types, i.e., different levels of wind production (<33% of total production and 67-100% of total production) and planned cross-border energy flow, had a considerable effect on the average probabilities of pricing differences. Oggioni and Smeers (2013) showed that electricity produced from intermittent renewable energy sources, such as wind, not only increased price differences but became more pronounced in markets that uses pricing areas to mitigate congestion. Nord Pool implements this type of area pricing scheme, and in this study the large effect from the different predicted wind shares levels were noted in the DK1-NO2 and DK1-SE3 models but to a lesser degree in the DK1-DK2 model.

This result opens future research for at least two topics. Firstly, to investigate the percentage of time with equal prices required in two trading areas so that predicted wind levels have little effect on pricing outcomes. Secondly, could the percentage of time with equal prices be smaller if a nodal pricing scheme were employed?

In the four years studied here, there was not a year when the time share of equal prices was less than 70% between DK1-DK2 (Table 26). Among the four trading partners, DK1 exports on average the most energy to DK2 (311.88 MWh) in its day-ahead market (see Table 28), which may indicate that there is enough transmission capacity between DK1-DK2 to keep price differences relatively uninfluenced from different predicted wind share levels.

Finally, this may lead to the conclusion that increased interconnection can reduce price differences such as occurred between Belgium, the Netherlands, and France when the percentage of the time the price was different fell from 90% to 37% after market coupling in 2007 (Küpper et al., 2009). Therefore, it may be possible to conclude that if different wind levels do not have a large effect on pricing differences between trading partners, then there may be enough interconnector transmission capacity between trading partners.

In conclusion, price sensitivity to wind may be thwarted by increasing transmission capacity between countries, although one caveat for policy makers to consider will be the uncertain future of nuclear power, as Sweden and Germany seek to phase-out nuclear power generation in the coming years (de Menezes and Houllier, 2015; World Nuclear Association, 2016a; World Nuclear Association, 2016b). This decrease in supply could disrupt price convergence between different countries operating in one common market.

7 Concluding Remarks and Recommendations

It has been roughly seventeen years since the electricity markets in Norway, Sweden, Denmark, and Finland became integrated by operating under a single pricing mechanism in the Nordic day-ahead electricity market, Nord Pool. Over time, market rules, design, and boundaries have been adjusted to handle the changes connected to the growth of renewable electricity and geographical expansion.

There were three research objectives in this dissertation and each analysis was performed at a different geographical level. The first objective was performed at a regional level. It sought to explore from a descriptive perspective how market coupling between Nord Pool and the Central Western European market affected the market clearing price, along with calculating the price differences between Nordic trading partners under different trading alternative for the corresponding Nordic area and its Central Western European trading partner. The results showed a distinct pattern between western Denmark and southern Norway in that the largest price differences occurred between these two areas, while smaller price differences corresponded to intra-national trading partners. As Price (2007) discussed, there may be more incentive to handle intra-national congestion than international congestion. Unfortunately, this could potentially impair investment decisions focused on building up the infrastructure used to support the interconnection between countries and thus preventing progress in achieving more uniform prices.

It is recommended that the geographical boundaries for the pricing areas not be constrained to national boundaries. For example, eastern Norway (NO5) and Finland may constitute one pricing area. This recommendation may be difficult to achieve, given the differences in national policies and primary objectives of each nation. It is also recommended that there are clear rules for distributing gains from market integration to the public so that investment in interconnection will not become concentrated.

The second objective of this research was to understand how unilateral decisions related to changes in energy targets at the national level would affect day-ahead prices in neighboring countries. This research question was addressed by building three ordinary least-squared models (OLS) that estimated the effect of changes in the different Nordic countries' (excluding Iceland) electricity supply on day-ahead market prices. The models were constructed using electricity supply variables (combustibles, nuclear, hydropower, and wind, solar, and biomass) from Norway, Sweden, Finland, and Denmark. According to the results of the Ramsey (1969) test, the system price model suffered from omitted variables, while the models for Denmark and Finland were fully specified and were not biased due to omitted variables (see Table 22).

The overreaching result from this analysis was that changes in one country's electricity generation mix can affect electricity prices in neighboring countries, although this effect will vary between nations.

To avoid conflict around national energy policies, there must be more harmonization between nations and their energy policies in an integrated electricity market. While this may require enormous effort in the short-run for politicians and key stakeholders, it may ensure greater energy security and more stable electricity prices over the long-run due to political stability. Unfortunately, to produce harmonization at this international level involves many stakeholders and the complexity increases immensely.

Currently, there are 28 European Union countries that belong to integrated electricity markets (i.e., exchange energy across borders) at varying levels. While pertinent to understanding the dynamics between these countries and how this will affect electricity market prices, performing analyses at this level will require a vast effort to capture these effects without comprising simplicity, since there is empirical evidence that suggests complexity does not necessarily improve forecast accuracy (Armstrong, 1986).

It is recommended that more multinational assessments of this type be performed to facilitate proper market integration. It is recognized that this is an arduous task when there is a large heterogeneous mix of countries, each with its own set of policies and unique electricity generation mix.

With that stated, an important step needed to facilitate these types of analyses at the international level is a standardization of definitions for different variables. Regulation 1227/2011/EU, also known as the Regulation on Wholesale Energy Markets Integrity and Transparency (REMIT), obliged both transmission system operators and market participants to publish a range of “transparency data” (European Parliament and of the Council, 2011). The REMIT regulation has now been in effect for several years and there have been some improvements. However, there remain large differences in the data published by the various stakeholders, which makes it hard to combine and compare data.

For example, the Finnish Energy Agency now publishes hourly electricity supply data (2010-2015) but the data records thermal power divided into three different categories: cogeneration of district heat, industry, and separate electricity generation (Finnish Energy Agency, 2016). In contrast, Statistics Sweden publishes electricity supply data at a monthly level and categorizes its thermal generation into four types (Statistics Sweden, 2016). Assessments of electricity prices are often done at either the hourly or daily level (Jónsson et al., 2010; Gelabert et al., 2011).

The issue that arises when estimating the effect of variables at different temporal resolutions is that either the fine scale variable needs to be aggregated or the coarse scale variable needs to be repeated as a constant for multiple fine scale observations. Both conditions will affect modeling. Also, due to differences in classification for power plants, a researcher needs to make subjective decisions for how to group or classify power plants across nations, and such decisions might not be traceable in future assessments.

It was further found while conducting this research that, while there is a strong aim to increase data transparency, there is a disconnect between Nord Pool and the transmission system operators who supply operating data to Nord Pool for publication. To elaborate, Nord Pool publishes operating data for Norway, Sweden, Finland, and Denmark. The operating data includes production, consumption and wind generation volumes. To date, there is no glossary of definitions on Nord Pool’s website for the different data variables such as total production. The experience during data preparation in this study suggests there needs to be more responsibility by those who publish data from other sources to clearly list how the different sources define a variable with the same label as other sources. Therefore, as data transparency improves, so does the need for standardizing definitions for variables. Otherwise, it is the responsibility of the source publishing the data to present all definitions and any changes that are relevant. The definition of terms and data transparency requirement may affect market outcomes. Clear definitions and transparency requirements can enhance economic welfare.

The third research objective was studied at a lower geographical perspective. The aim of the analysis was to compare planned energy flow across HVDC interconnectors and different levels of wind generation on pricing outcome between western Denmark and its other Nordic trading partners. A key conclusion was that increased interconnection could thwart price differences that occur due to the low production costs associated with renewable energy sources. It is recommended that more analyses be performed that evaluate how to prioritize investments in interconnection based on areas that have higher integration rates of renewable energy sources.

In conclusion, as other countries such as Iceland explore and assess potential projects that relate to interconnecting their electricity markets to other European nations, the nations' policy makers must remember that interconnection in an integrated market is not just a bilateral assessment. Furthermore, it may be expected that there will be a higher prevalence of price differences due to the different generation mixes. This is logical, and this research found there was a lower frequency of price differences and a lower annual price difference between areas that had the same generation mix than for those that did not. With this stated, the number of price differences can be reduced by increasing the transmission system capacity or with increased interconnection.

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Appendix A

Table A.1 Matrix of current Nordic and Baltic cross-border trading partners in Nord Pool.

	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4	EE	LV	LT
DK1		*			*						*				
DK2	*											*			
FI									*		*		*		
NO1					*	*		*			*				
NO2	*			*						*					
NO3				*			*	*							
NO4									*	*					
NO5				*		*									
SE1			*				*			*					
SE2						*	*		*		*				
SE3	*		*	*						*		*			
SE4		*									*				*
EE			*											*	
LV													*		*
LT												*		*	

PR;XO;2012;1;1;02.01.2012;SP1;228,20;221,85;214,72;215,26;223,63;233,54;248,03;268,40;281,57;285,21;289,24;288,54;278,31;275,53;278,24;282,65;284,98;285,90;276,22;270,72;263,83;258,25;248,41;228,43
PR;XO;2012;1;1;02.01.2012;NO1;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;274,67;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;FI;228,20;221,85;214,72;215,26;223,63;233,54;293,96;310,46;299,00;294,04;301,71;301,16;284,28;274,67;282,19;318,59;310,15;294,19;277,07;270,65;263,83;258,17;248,34;228,43;
PR;XO;2012;1;1;02.01.2012;NO3;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;EE;228,20;221,85;214,72;215,26;223,63;233,54;293,96;310,46;299,00;294,04;301,71;301,16;284,28;274,67;282,19;318,59;310,15;294,19;277,07;270,65;263,83;258,17;248,34;228,43;
PR;XO;2012;1;1;02.01.2012;NO2;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;274,67;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;DK2;228,20;221,85;214,72;215,26;223,63;233,54;247,72;296,75;297,76;309,84;342,37;348,34;309,38;274,67;280,56;290,55;348,18;495,74;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;NO4;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;DK1;228,20;221,85;214,72;215,26;223,63;220,84;216,50;296,75;297,76;294,04;301,71;313,56;271,88;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;NO5;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;274,67;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;SE1;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;SE2;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;SE3;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;XO;2012;1;1;02.01.2012;SE4;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;274,67;280,56;290,55;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;RO;2012;1;1;02.01.2012;NO1;228,76;222,39;215,25;215,79;224,18;234,11;248,32;266,11;277,52;278,22;277,99;277,13;275,97;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RO;2012;1;1;02.01.2012;NO3;228,76;222,39;215,25;215,79;224,18;234,11;248,32;266,11;285,83;294,76;302,45;301,90;284,98;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RO;2012;1;1;02.01.2012;NO2;228,76;222,39;215,25;215,79;224,18;234,11;248,32;266,11;277,52;278,22;277,99;277,13;275,97;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RO;2012;1;1;02.01.2012;NO4;228,76;222,39;215,25;215,79;224,18;234,11;248,32;266,11;285,83;294,76;302,45;301,90;284,98;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RO;2012;1;1;02.01.2012;NO5;228,76;222,39;215,25;215,79;224,18;234,11;248,32;266,11;277,52;278,22;277,99;277,13;275,97;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RN;2012;1;1;02.01.2012;NO1;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;276,36;277,68;279,07;278,06;275,81;271,31;264,48;258,81;248,95;228,99
PR;RN;2012;1;1;02.01.2012;NO3;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;292,90;294,91;277,75;271,31;264,48;258,81;248,95;228,99
PR;RN;2012;1;1;02.01.2012;NO2;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;276,36;277,68;279,07;278,06;275,81;271,31;264,48;258,81;248,95;228,99
PR;RN;2012;1;1;02.01.2012;NO4;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;292,90;294,91;277,75;271,31;264,48;258,81;248,95;228,99
PR;RN;2012;1;1;02.01.2012;NO5;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;276,36;277,68;279,07;278,06;275,81;271,31;264,48;258,81;248,95;228,99
PR;RC;2012;1;1;02.01.2012;NO1;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RC;2012;1;1;02.01.2012;NO3;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RC;2012;1;1;02.01.2012;NO2;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RC;2012;1;1;02.01.2012;NO4;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RC;2012;1;1;02.01.2012;NO5;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RP;2012;1;1;02.01.2012;NO1;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RP;2012;1;1;02.01.2012;NO3;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RP;2012;1;1;02.01.2012;NO2;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RP;2012;1;1;02.01.2012;NO4;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;285,13;294,04;301,71;301,16;284,28;275,35;281,25;291,27;344,90;344,90;349,43;330,96;310,00;310,00;269,13;269,13
PR;RP;2012;1;1;02.01.2012;NO5;228,20;221,85;214,72;215,26;223,63;233,54;247,72;265,46;276,84;277,54;277,31;276,45;275,29;275,35;281,25;291,26;344,90;344,90;320,00;330,96;310,00;310,00;269,13;269,13
PR;RS;2012;1;1;02.01.2012;NO1;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;RS;2012;1;1;02.01.2012;NO3;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;RS;2012;1;1;02.01.2012;NO2;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;RS;2012;1;1;02.01.2012;NO4;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;281,25;291,27;292,18;294,19;277,07;270,65;263,83;258,17;248,34;228,43
PR;RS;2012;1;1;02.01.2012;NO5;130,00;125,00;115,00;100,00;100,00;120,00;150,00;190,00;200,00;210,00;210,00;210,00;225,58;275,35;275,68;277,00;278,39;277,38;275,14;270,65;263,83;258,17;248,34;228,43
PR;DD;2012;1;1;02.01.2012;NO1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;0;1;1;1;1;1;1;1;1;1;1
PR;DD;2012;1;1;02.01.2012;NO3;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;0;0;0;1;1;1;1;1;1;1;1
PR;DD;2012;1;1;02.01.2012;NO2;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;0;1;1;1;1;1;1;1;1;1;1
PR;DD;2012;1;1;02.01.2012;NO4;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;0;0;0;1;1;1;1;1;1;1;1
PR;DD;2012;1;1;02.01.2012;NO5;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;-1;0;1;1;1;1;1;1;1;1;1;1

Figure A.1. Screen shot of raw data file given by Nord Pool.

Perl script written to transform Nord Pool data.

```
use FileHandle;
use strict;
use warnings;

my $run_type = shift @ARGV;
my $missing_value = -9;

my ( $outfile, $header );

if ( $run_type eq "pr" ) {
  $outfile = "price";
  $header = "price";
}
elsif ( $run_type eq "unit" ) {
  $outfile = "unit";
  $header = "unit";
}
else {
  die "invalid code\n";

}

my %files = ();
my %codes = ();
my $headers;

foreach my $infile ( map { glob } @ARGV ) {
  getCodes($infile,\%codes);
}

foreach my $code ( keys %codes ) {
  my @header = qw( hour week day_week day month year exporter );

  $files{$code} = new FileHandle;

  open( $files{$code}, ">", "${outfile}_${code}_$codes{$code}.csv" )
   or die "Cannot open outfile ${outfile}_${code}.csv: $!\n";

  print "\topened ${outfile}_${code}_$codes{$code}.csv\n";

  if ( $codes{$code} eq "i" ) {

    push @header, "importer";
  }

  if ( $run_type eq "unit" ) {

    push @header, "unit";
  }

  push @header, $code;

  $headers->{$code} = \@header;
  print { $files{$code} } join( ",", @header ), "\n";
}
```

```
foreach my $infile ( map { glob } @ARGV) {
  prepare_data($infile);
}

foreach my $code ( keys %files ) {
  close( $files{$code} );
}

print "Done!\n";

### subroutines

sub prepare_data {
  my $infile = shift;

  open( my $fh, "<", $infile )
   or die "cannot open infile $infile\n";
  print "preparing $infile\n";

  my $n = 0;
  while (<$fh>) {

    if ( $_ =~ /^#|(ST)|(BE)|(AL)/ ) {
      next;
    }

    next if m/^\s*$/;

    s/\015?\012//g;
    #s/\./;/g;
    s/,/\./g;
    s/\"//g;

    my @row = split /;/, $_, -1;

    # ignore empty rows
    next unless @row;

    # create variable code from first and second column

    my $code = "$row[0]_$row[1]";
    shift @row;
    shift @row;
    shift @row;

    my @outrow = ();
    my $record;

    $record->{week} = shift @row;
    $record->{day_week} = shift @row;
    @{$record}{ qw(day month year) } = split /\./, shift @row;
    @{$record}{ qw(exporter importer) } = split /_/, shift @row;

    if ( $run_type eq "unit" ) {
      $record->{unit} = shift @row;
    }

    if  (defined($record->{importer})  &&  $record->{exporter}  eq  "FI"  &&
$record->{importer} eq "SE1") {
```

```
      sleep 1;
    }


    pop @row;

    my $hour = 1;
    while ( scalar @row ) {

      $record->{$code} = shift @row;

      unless ( defined $record->{$code} ) {

        $record->{$code} = $missing_value;
      }

      #if ($record->{$code} eq "" ) {
      #
      #  $record->{$code} = $missing_value;
      #}


      $record->{hour} = $hour++;
      save_record( $code, $record );
    }
  }

  close($fh);
}

sub save_record {

  my $code = shift;
  my $record = shift;

  foreach my $header ( qw( exporter importer ) ) {

    unless ( defined $record->{$header} ) {

      $record->{$header} = "";
    }

    $record->{$header} =~ s/JY/DK1/;

    $record->{$header} =~ s/SJ/DK2/;
  }

  $record->{$code} =~ s/,/./;

  if ( $run_type eq "unit" ) {

    unless ( $record->{unit} && ( ( $record->{unit} eq "EUR" ) or (
$record->{unit} eq "MWh/h" ) ) ) {

      return;
    }
  }

     #print "code $code; file: $files{$code}; .\n";
```

```
  print { $files{$code} } join( ",", @{$record}{ @{ $headers->{$code} } }
), "\n";
}

# Finds if the variable has only exporter data, or both export and import
and returns
# a hash of e or i for each variable code
sub getCodes {
  my $infile = shift;
  my $codes_ref = shift;

  open( my $fh, "<", $infile )
   or die "cannot open $infile\n";

  while (<$fh>) {

    if ( $_ =~ /^#|(ST)|(BE)|(AL)|(^\s+$)/ ) {
      next;
    }

    s/\015?\012//g;
    s/\"//g;
    my $row = $_;

    my $have_importer = 0;
    if ( $row =~ /_/ ) {

      # the exporter and importer are separated by _
      # so we find if we have an importer by finding _
      $have_importer = 1;
    }

    my @row = split /;/, $_;

    my $code = "$row[0]_$row[1]";

    if ( !$codes_ref->{$code} ) {
      $codes_ref->{$code} = "e";
    }

    if ($have_importer) {
      $codes_ref->{$code} = "i";
    }

  }

  close($fh);

  return 1;
}
```