STOCKHOLM SCHOOL OF ECONOMICS
Department of Economics
5350 Master's thesis in economics
Spring 2014

The welfare effects of integrating electricity markets

- How differences in production technologies affect trade between the United Kingdom and the Nordic countries

Sandra Attermo (21926) and Jonni Fidler-Dennis (40297)

Abstract

The European Union aims to create a single European integrated electricity market. At present there are concrete plans to connect the electricity markets of the United Kingdom (UK) and the Nordic countries. Due to differences in electricity generation technologies, the UK has a relatively more expensive electricity market than the Nordics. In this thesis we investigate the welfare effects of electricity trade between these two regions. We run several scenarios with varying capacity of production sources such as wind, nuclear and hydropower in order to analyse how these changes affect trade patterns. A partial equilibrium model is used to determine the effects on prices and on the consequent welfare of consumers and producers in each region. Our results suggest that, in general the Nordic countries export electricity and prices converge. Consequently, consumers in the UK gain while their producers lose. In the Nordic countries the reverse happens. Furthermore, the variability of output of certain production technologies such as wind power and hydropower can at times substantially affect prices, which in turn can lead to swift changes in the direction of trade. Future benefits of trade are hence dependent on future generation mixes as well as factors that can affect generation output such as weather conditions.

Keywords: electricity market integration, welfare effects of trade, intermittent energy sources

JEL: F170, F180, Q410, Q420

Supervisor:	Chloé Le Coq
Date submitted:	14 May 2014
Date examined:	27 May 2014
Discussant:	Ida Frössander and Johannes Kasinger
Examiner:	Karl Wärneryd

1. Introduction **3**
2. Background **5**
Special properties of electricity **5**
The European electricity markets **6**
The European Target Model and market integration in the electricity sector 7
Climate and renewable energy targets 8
Zonal and nodal pricing **10**
Market coupling **11**
Financial aspects of energy trading **12**
The United Kingdom's electricity market **13**
The Nordic electricity market **15**
Electricity trade and the power exchanges in the Nordics and the United Kingdom **16**
APX Power UK and Nord Pool Spot AS 17
3. Literature review **18**
Electricity integration, welfare effects and market coupling **18**
Electricity integration and renewable energy **22**
4. Purpose and motivation **23**
Comparison to Doorman & Frøystad (2013) 24
Research Questions **25**
Scenarios **25**
5. Theoretical framework **28**
A Partial equilibrium model for the electricity market **28**
Partial equilibrium model with trade **32**
6. Hypothesis **35**
7. Method and data **36**
Calibration of the model 42
Calculation of welfare effects 42
Data 43
8. Results and analysis **44**
Do our simulations correspond to the actual data? 44
Welfare effects from trade in the Nordics and the United Kingdom with the generation mix of today 45
Welfare effects from trade in Norway and the United Kingdom with the generation mix of today 46
Welfare effects from trade in the Nordics and the United Kingdom with more wind power 48
What is the environmental effect of trade? 49
What happens when we enable free trade? 50
9. Discussion **51**
Wider implications of electricity trade 53
10. Conclusions **55**
References **57**
Appendix **68**
Appendix 1, costs of fossil power production **68**
Appendix 2, input variables **70**

1. Introduction

In line with current European Union (EU) directives, European countries are making progress in creating a single European electricity market. In the last decade, integration has seen rapid progress and more and more countries are now interconnected (ACER & CEER, 2013). However, much is left to do in order to reach full integration and there are currently numerous ongoing and proposed projects aimed at improving interconnection capabilities between electricity systems ("List of projects", 2012).

In addition to ambitions of a single European electricity market, the EU has set targets for reducing its environmental impact. The main objective is that by the year 2020, greenhouse gas emissions are to be 20% below the levels of 1990. This is to be accomplished by having 20% of energy consumption generated by renewable sources as well as achieving improvements in energy efficiency by 20%. These overall targets have been translated into different national targets, and countries have in a variety of ways taken steps towards fulfilling these (The 2020 climate and energy package, 2014). Examples of renewable energy sources are wind and solar power, hydro-electric power and biomass, where wind power is the major technology countries have chosen to invest in (EWEA, 2011). A drawback with wind power, as is true for other renewable technologies such as solar power, is that the amount of electricity generated is dependent on weather conditions. As a result, supply is unpredictable and can fluctuate greatly (Schaber, Steinke, Mühlich & Hamacher, 2012). To a lesser extent, the amount of hydropower available also fluctuates as it is dependent on yearly weather variations. Dry years might lead to less hydropower while wet years can give a surplus.

A distinguishing property of electricity is that it cannot easily be stored, which means demand and supply must constantly be balanced (Heddenhausen, 2007). The increased dependence on intermittent technologies leads to difficulties in predicting supply, which puts extra pressure on the electricity system. Measures taken to avoid the prospect of blackouts include having flexible generation sources, such as coal or gas plants, ready to be quickly activated if required, and to engage in trade, enabling electricity import if necessary or export in the event of excess production. With sufficient trading capabilities difficulties associated with supply issues may be mitigated (Schaber et al., 2012).

In the 1990s, two of the first regions in Europe to liberalize and privatize their electricity markets were the United Kingdom (UK) and the Nordic countries. In each of these regions, a wholesale and

a retail market has developed, resulting in increased competition as well as more choices for consumers (Amundsen, Bergman & Fehr, 2006; House of Commons Energy and Climate Change Committee, 2011). In order to attain the EU's environmental targets, both the Nordics' and the UK's investments in renewable energy sources, especially in wind power, have considerably increased. Despite mentioned similarities, their electricity markets are to a large degree different, in particular the structure of their electricity generation mixes. The majority of the Nordic region's electricity generation is made up of hydropower while the UK's generation is dominated by the burning of fossil fuels. As hydropower has substantially lower marginal cost in comparison to fossil fuels, electricity prices are often considerably lower in the Nordic countries. Taking the structural differences into consideration, trade between these two regions would lead to overall gains according to economic theory. This notion is supported by research. Moreover, besides overall gains being achieved, trade results in redistribution of welfare amongst groups. Hence, trade generates both winners and losers, and opposition towards creating a single European electricity market exists (Parisio & Bosco, 2008; Førsund, 2009).

Nevertheless, integration is increasing. At present, there are two projects aiming to facilitate direct trade between the UK and the Nordic countries by building electricity interconnectors. More specifically, there are plans to construct connections between the UK and Norway. In one of the projects, the transmission system operator in each region, National Grid in the UK and Stattnet in Norway intend to build a 1400 MW interconnector between Norway and England by 2020. In the other, NorthConnect, a commercial joint venture owned by Vattenfall AB, Agder Energi, E-CO and Lyse (Welcome to the NorthConnect web site, n.d.), plans to build one between Norway and Scotland. This interconnector is also to have a capacity of 1400 MW (EWEA, 2013, p. 27) and is proposed to be in operation by 2019 ("List of projects", 2012).

Several positive aspects of these two projects are highlighted. National Grid and Stattnet deem their connection to be commercially worthwhile as well as contributing to both Norway and the UK's security of supply (EWEA, 2013, p. 27). NorthConnect emphasizes several reasons as to why their interconnector would be beneficial. As Scotland aims to invest heavily in wind power an interconnector would help provide electricity supply reserves to Scotland (and to the whole of the UK) when needed. Norway, having large amounts of hydropower, could gain by relying on imported electricity when their hydro dam reservoirs need to be refilled. Additionally, the UK could, by importing clean hydropower be aided in its bid to meet its renewable energy targets. Also, consumers in the UK could get lower prices by importing electricity at times when domestic

electricity is more expensive (What is NorthConnect?, n.d.).

Judging by these companies, there are many benefits of enabling electricity trade between the UK and Norway. With advanced plans set in motion, interconnectors linking these two markets appear soon to be realized. Our aim is to investigate further the effects of electricity trade on welfare in the UK and Nordic countries (excluding Iceland). We intend to accomplish this by using a partial equilibrium model to analyse how electricity trade affects electricity prices in each region and the consequent impact on the welfare of consumers and producers. Furthermore, we aim to add to the current literature regarding electricity trade by using several scenarios to examine how differences in generation technologies as well as the variability of hydro and wind power production affects trade patterns.

This thesis is organized as follows. In section 2, some basic concepts regarding electricity and the electricity market in general will be described. Section 3 will give a brief overview of current literature regarding electricity integration. In section 4 our purpose and research question will be stated, in section 5 the theoretical framework will be presented, which will be followed by our hypothesis in section 6 and our method in section 7. Our results will be shown in section 8, while, in section 9, we will discuss our findings and in section 10, the conclusions of our study will be presented.

2. Background

This section will contain an overview of electricity and the electricity markets of Europe, in particular the UK and the Nordic markets and their power exchanges, as well as how these markets are becoming more integrated. Additionally, the EU's renewable energy targets will be touched upon.

Special properties of electricity

National electricity markets have historically been highly regulated due to the properties of electricity, which make it different from other commodities (Heddenhausen, 2007). The main difference is that electricity cannot be stored in an economically meaningful way. As a consequence, generated supply and electricity demand must match at all times in order to avoid blackouts. This being said, with hydropower there is an exception regarding the difficulty of storing electricity. As hydropower often uses water dam reservoirs there is flexibility in how much

electricity can be produced each hour. In this sense, to some degree electricity can be stored in the form of water in the reservoir. However, the storage problem remains with electricity that has already been generated. One solution is that when there is excess electricity supply and low prices, this electricity can be used to pump back used water from a reservoir situated at lower elevation to one at a higher. Thereby the higher reservoir is refilled and the water can be re-used to generate electricity. This is called Pumped Hydropower Storage (PHS) and is regarded as an effective way of storing electricity. However, far from all countries have the natural conditions available to have hydropower, which also means that the ability to store electricity by using PHS varies between countries (Gimeno-Gutiérrez & Lacal-Arántegui, 2013). Regarding the demand for electricity, it is difficult to control and fluctuates considerably depending on yearly seasons, weekdays and hour of day (OFGEM, 2010). To handle varying demand, a variety of generation technologies are required such as nuclear power, hydro, coal-fired, wind, CHP and gas-fired turbines (Price formation in Nord pool spot, n.d.). Flexible generation technologies are commonly needed at demand peaks and this generation is made up to an increasing degree of relatively more expensive fossil fuels (OFGEM, 2010).

To ensure that demand is always met, there is a need for excess capacity incurring extra costs for suppliers. Electricity is also network bound and as duplicating electricity transmission networks is very expensive this has resulted in the formation of natural monopolies. Market power problems can occur as network congestion together with the inability to store electricity may obstruct geographic expansion of competition. Additionally, electricity is crucial for the workings of modern society, both economically and socially. As there are no real substitutes any market failure would result in immediate negative economic and welfare consequences (Heddenhausen, 2007, p. 4).

The European electricity markets

Prior to the 1990s most countries in the EU deemed their electricity markets to be kept from privatization and competition due to the sector's macroeconomic significance, capital intensity and technical complexity. With the emergence of the European common market in the early 1990s, price differences in electricity between countries became an important factor for the competitiveness of national companies. To avoid the prospect of production moving to lower-priced countries, several states favoured a EU-wide reform of the electricity markets. However, opposition to this was still strong as many viewed a reform being too focused on economic properties and neglecting the public service aspects of electricity companies. It took until 1996

before a common position was agreed upon and the first formal EU-wide steps towards an internal electricity market were taken (Heddenhausen, 2007).

Since 1996, the liberalization and integration of electricity markets has intensified across Europe. Up until 2004 the focus was primarily in a national context, on shifting from monopolistic markets to liberalized national markets. Although market structure reforms and efforts to increase competition are still ongoing, post-2004 emphasis has been on introducing market coupling in order to enable cross-border electricity trading. With market coupling, interconnections are more efficiently used by simultaneously clearing their capacity with all bids and offers into the day-ahead auction. The aim is to have market coupling facilitated across Europe by 2014, although some delay is expected before the whole of Europe is covered (Newbery, Strbac, Pudjianto & Noël, 2013).

The European Target Model and market integration in the electricity sector

The EU's goal of creating a single integrated European electricity market is being achieved by what is referred to as the European Target model, which includes three legislative packages of directives and regulation (Single market for gas & electricity, n.d.). To summarize, the first package included a directive, 96/92/EC, concerning common rules for an integrated electricity market. Building further on this, the second package arrived in 2003 with the addition of regulation on the conditions for access to the network for cross-border exchanges in electricity (Directive 2003/54/EC; Regulation (EC) No 1228/2003). The third package from 2009 included the mandates for creating a legal framework for the implementation of market coupling through the establishment of the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators in Electricity (ENTSO-E). ACER has developed framework guidelines on capacity allocation and congestion management while ENTSO-E, whose members are all EU transmission system operators, is responsible for developing network codes that follow the framework guidelines (European Commission, 2011). The network codes include rules and procedures concerning topics such as network security and reliability, data interexchange, technical and operational exchanges, transparency rules, harmonized transmission tariff structures and energy efficiency (Regulation (EC) No 714/2009).

The Association of European Energy Exchanges (Europex) represents the power exchanges and while not being provided with any legislative charges, it plays an important role in implementing market coupling (European Commission, 2011). The goals Europex works towards are, by

supporting power exchanges, the implementation of the European single electricity market and increased competition through price transparency. It promotes the liberalization of the different European electricity systems, provide a market solution to congestion problems as well as work towards increasing co-operation between European power exchanges and free trade (EuroPEX, 2004).

The goal of these packages is, in short, to present common rules for the generation, transmission, distribution and supply of electricity in the EU. This is aimed at enabling any citizen or company to achieve efficiency gains, competitive prices, higher standards of service, security of supply and sustainability through new business opportunities and cross-border trade. Consumers should be able to choose any supplier while all suppliers should be able to freely deliver electricity to their customers. The hope is that a common integrated market will give electricity producers incentives to invest in new generation technology, including renewable energy, as well as encourage consumers to use electricity more efficiently in order to secure supply (Directive 2009/72/EC).

Climate and renewable energy targets

The EU and its member states have set climate and energy targets aiming at stabilising greenhouse gas emissions at a level that would not seriously affect the climate system. The overall objective is to prevent global annual mean surface temperatures from increasing by more than 2° C above levels of the pre-industrial era (Decision No 406/2009/EC). In order to reach this objective a binding 2020 climate and energy package has been adopted. In short, there are four main targets that are to be achieved by the EU as a whole by the year 2020. Firstly, the main overall goal to be attained is to reduce the EU's greenhouse gas emissions by at least 20% compared to the levels of 1990 (Directive 2009/29/EC). Secondly, 20% of the EU's energy consumption is to be produced by renewable energy sources. Thirdly, energy efficiency is to be increased by 20% and lastly, 10% of the energy used in transport is to consist of renewable sources (Directive 2009/28/EC).

In order to reach these overall targets, EU member states have undertaken binding national targets to be achieved by 2020. These national targets vary across countries as they reflect different starting points and potential for increasing renewable energy sources (The 2020 climate and energy package, 2014). As the regions of interest for this thesis are the UK and the Nordic countries, a short summary of their respective national targets follows. Although Norway is not a member of the EU, the country has adopted the union's renewable energy targets. Table 1 shows an overview of each country's respective overall goals as well as targets per sector.

Table 1, share of renewable energy per country and per sector

	Share of renewable energy of gross final energy consumption in %		Share of renewable energy targets per sector in 2020 in %		
Country	**2005**	**The 2020 national target**	**Electricity**	**Heating and cooling**	**Transport**
The UK	1.5	15	30	12	10
Denmark	17	30	51.9	38.9	10.1
Norway	60.1	67.5	113.6 (inc. export)	43.2	10
Finland	28.5	38	33	47	20
Sweden	39.8	50	62.9	62.1	13.8

The UK's energy sector has been very dependent on fossil fuels such as gas, coal and oil though the use of renewable sources is increasing. The aim is that by 2020, 15% of their gross final energy consumption is to be based on renewables, which can be compared to 1.5% in 2005. To meet the goal a framework has been set up consisting of, amongst other things, financial support for renewables and the developing of emerging technologies. Financial support is aimed at increasing investments in renewable energy and when it comes to emerging technologies offshore wind is a key area while developing marine energy using wave and tidal resources is also a priority (Department of Energy & Climate Change, 2010).

Denmark has set a target of having 30% of gross final energy consumption from renewable energy, up from 17% in 2005. In the 1970s Denmark's energy system almost entirely relied on imported coal and oil. Since then efforts have been made to create a variety of energy sources with the focus in recent years being renewables such as wind power, biodegradable waste and biogas. To achieve this development a support scheme has been developed to promote renewable energy consisting of such measures as subsidies, tax exemptions, political agreements on the establishment of wind farms and information campaigns and research (Klima- og Energiministeriet, 2010).

Norway´s share of renewable energy is much higher than in any country in the EU and almost all its electricity production is based on hydropower. Norway had in 2005 an overall share of 60.1% of gross final consumption consisting of renewable energy sources. By 2020 the aim is to increase this share to 67.5%. An important element in how Norway supports increased use of renewable energy is by the establishment of the joint Norwegian-Swedish electricity certificate market with the aim to promote mainly wind, water and bio energy. Other efforts made are increased investments in the electricity grid as well as in research and development of renewable technologies, energy efficiency and environmentally friendly transport (Ministry of Petroleum and Energy, 2012).

Finland aims to have an overall share of renewable energy to be 38% of gross final consumption. This is an increase from 28.5% in 2005. Finland promotes renewable energy through channels such

as subsidies, investment support schemes and tax exemptions. Areas of focus are, for example wind power, energy production using wood chips, small CHP plants, hydropower and biofuels in transport (Ministry of Employment and the Economy, 2010).

Sweden's share of renewable energy by 2020 was set by the EU to be 49% of gross final energy consumption. However, Sweden has changed this target to 50%. This compares to a share of 39.8% in 2005. Sweden has promoted the use of renewable energy for many years with the aim of reducing its environmental impact and dependency on oil as well as increasing the efficient use of resources and new technologies. Sweden's long-term energy policies include carbon dioxide taxes and an electricity certificates market. Additionally, Sweden gives financial support to energy research within areas concerning renewable energy. There are also state-aid programs that help fund investments in solar power, the distribution and use of biogas as well as other renewable gases, and the market introduction of wind power (Regeringskansliet, 2010).

Looking beyond the 2020 package, a new proposed framework with updated targets to be achieved by 2030 was presented by the European Commission in January 2014. Included is the aim to reduce domestic greenhouse gas emissions by 40% below the levels of 1990 and increase the share of renewable energy to 27% of the EU's energy consumption. The framework is to be decided on by the latest October 2014 (The 2030 framework for climate and energy policies, 2014).

Zonal and nodal pricing

As mentioned, plans to fully integrate the electricity markets of Europe are in motion. However, there are still bottlenecks and transmission constraints both within and between countries creating congestion (ACER & CEER, 2013).

The transmission system operators are those responsible for managing congestion issues. One way to do so is by dividing the electricity markets into different areas, each with potentially different prices depending on congestion (ENTSO-E, 2014). With no congestion on electricity flows, prices across areas are the same. However, in the event of congestion in an area, prices there will increase compared to uncongested areas resulting in different area prices (Bidding areas, n.d.).

There are two commonly used methods as how to divide up the electricity grid. The European Electricity Target Model assumes a zonal pricing approach, which means that each area is a portion of the electricity system, consisting of a group of electricity nodes. This area can either be a whole country or a region in a country (Oxera, 2013). In each zone it is assumed that there is sufficient

transmission capacity such that electricity can be exchanged without any bottlenecks and congestion while exchange between zones might be constrained due to limits in cross-connections (ENTSO-E, 2014). In the other approach, nodal pricing, each area is based on a point, an electrical node, in the system. With nodal pricing, at each node there will be a unique price. In zonal pricing, on the other hand, there is a common price in the entire zone (Oxera, 2013).

When the electricity market is divided up according to the zonal pricing approach, the market price is determined by the clearing price of the last generated megawatt to meet load anywhere within the given geographical zone. As a consequence, the occurrence of congestion at one electrical node within the defined area will lead to increased prices for everyone in that area. In contrast, with nodal pricing, the only ones who will get increased prices are the ones depending on the specific congested node. Hence, zonal pricing tends to lead to overall higher prices. As zonal pricing incurs higher costs for consumers and does not fully reflect local conditions, nodal pricing is in many cases considered to be superior (Efficient Dispatch Toolkit Steering Committee , 2011).

The reason why regulators in the EU and around the world have adopted zonal pricing is that it was thought to reduce the intricacy of the pricing settlement. It was also motivated politically as having multiple prices within, for example, a country, as would be the case with nodal pricing, was not considered to be acceptable (Holmberg & Lazarczyk, 2012).

However, as zonal pricing has shown to be inferior in many ways, the long-term goal of the EU should be to adopt nodal pricing (ERGEG, 2010, p. 30). This has, as an example, already been accomplished for most of the United States (Efficient Dispatch Toolkit Steering Committee, 2011).

In the Nordics, each national transmission system operator chooses if or how to divide its country into different areas or zones. These areas are also called bidding areas, as bids and offers for electricity by market participants are made in each area. In Norway there are, as of now, five zones but that number can change while Denmark is always divided into two areas. As of 2011, Sweden consists of four while Finland and the Baltic countries have one each (Bidding areas, n.d.). The UK is not divided up into different zones but this is to be considered in the future (Kunz, 2012, p. 37; OFGEM, 2012).

Market coupling

In order for electricity to flow between bidding zones there has to be a mechanism that manages available interconnection capacity. One way to handle this is through explicit auction. With

explicit auction an interconnector's transmission capacity is independently auctioned on a market place separate from any electricity auction. As capacity and electricity are traded independently, insufficient price information about the other commodity might result in inefficient utilization of interconnectors. As a result, explicit auction is considered an inadequate method of handling the capacity of interconnections between bidding areas. Instead, market coupling, using implicit auction, is the mechanism selected to integrate the electricity markets of Europe (Explicit and implicit capacity auction, n.d.).

More specifically, with market coupling, the current electricity flow on a given transmission interconnector is reflected in the market prices obtained from the power exchanges. Hence, the price paid reflects both the cost of electricity in a bidding area as well as the congestion cost (Explicit and implicit capacity auction, n.d.). With this inclusion of relevant pricing for congestion, the price signals in the electricity spot markets determine cross-border electricity flow. This better utilizes transmission grid capacity and leads to price convergence as electricity flows from low price areas to high price areas. Consequently, market coupling facilitates a European-wide price formation mechanism and improves the integration of Europe's electricity markets (European Commission, 2011). In addition to facilitating market coupling in order to integrate day-ahead markets, the EU aims to create a single intraday market using implicit capacity allocation by the end of 2014 (ACER, 2011). The existence of a well-functioning intra-day market is increasingly important due to the growing use of intermittent electricity sources such as wind power (Borggrefe & Neuhoff, 2011). The transmission system operators together with the power exchanges are the ones responsible for establishing market coupling in Europe (European Commission, 2010).

The implementation of market coupling is expanding and is soon to be in place across the majority of Europe. With the launching of the North-Western Europe (NWE) day-ahead price-coupling project in February 2014, power exchanges from countries accounting for 75% of European electric consumption now calculate electricity prices using the same algorithm and set of harmonized operational procedures ("Successful operation of PCR solution", 2014)

Financial aspects of energy trading

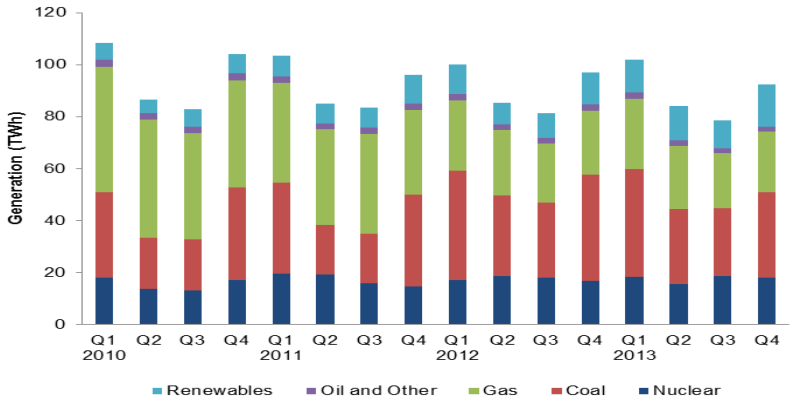
With the liberalization of Europe's energy market electricity and gas trading has considerably increased. Several over-the-counter (OTC) markets and exchanges have developed to handle the wholesale power trading (Karan & Kazdag˘li, 2011, p. 18-19). Initially, OTCs dominated and handled most of the volumes. However, power exchanges have now become the main platforms of

electricity trade (Jaakko Karas, 2013). Electricity trading helps manage volatile market conditions and has been seen to lower prices for consumers. Also, transparent market information contributes to increased competition and market efficiency. The development of different trading markets, such as day-ahead and forward markets as well as intra-day and balancing markets has greatly contributed to the integration of Europe's electricity markets (Karan & Kazdag˘li, 2011, p. 18-19).

The United Kingdom's electricity market

England, Scotland and Wales together form a single electricity market. The British transmission network is linked to other networks through interconnections, enabling electricity import and export. As of today, there are interconnectors to France, the Netherlands, Ireland and Northern Ireland. The UK's generation mix consists of fossil fuels, nuclear power and renewables. The burning of fossil fuels, with gas and coal being the dominant sources, generates the majority of electricity. Renewables, mainly wind power, though still accounting for a small part, have increased considerably in recent years as efforts are made to move towards cleaner electricity (Department of Energy & Climate Change, 2013). In the UK, electricity intensive industries' importance to the overall economy is quite small and they employ only about 2% of the workforce. However, these industries are of local importance as industrial sites are often located in areas with lower standards of living and high unemployment. As current climate and energy policies such as the EU Emissions Trading scheme negatively impact electricity intensive industries, they receive government support to stay competitive (Energy intensive industries, 2012).

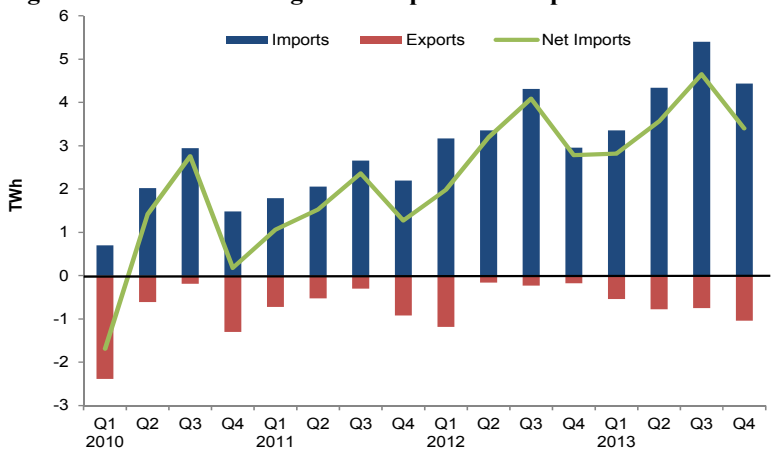
Figure 1.The United Kingdom's generation mix



(Department of Energy & Climate Change, 2014)

In 2012 total electricity generation in the UK was about 364 TWh while aggregate demand was about 376 TWh, the difference being imported (Department of Energy & Climate Change, 2013).

Figure 2. The United Kingdom's imports and exports



(Department of Energy & Climate Change, 2014)

The UK was the first country in Europe to take steps towards the liberalization and privatization of its electricity market in the late 1980s. Prior to its liberalization the British supply industry had been centralized and dominated by a state owned monopolist but has since seen growth of both suppliers and producers increasing competition (Heddenhausen, 2007).

The latest reform occurred in 2001 when the New Electricity Trading Arrangements (NETA) were initiated in England and Wales changing the form of electricity trade. In 2005 these arrangements were extended to Scotland under the British Electricity Trading and Transmission Arrangements (BETTA) to form a single Great Britain transmission network operated by the transmission system operator National Grid plc. The NETA/BETTA is based on bi-lateral trading between producers, suppliers, traders and consumers (Department of Energy & Climate Change, 2013). There is an electricity wholesale market between electricity producers and suppliers intended to increase

competition and efficiency. In the retail market electricity is sold between suppliers and consumers giving consumers the freedom to choose supplier. These arrangements aim at creating a system that maintains a secure and reliable electricity system while offering more options to market participants (House of Commons Energy and Climate Change Committee, 2011).

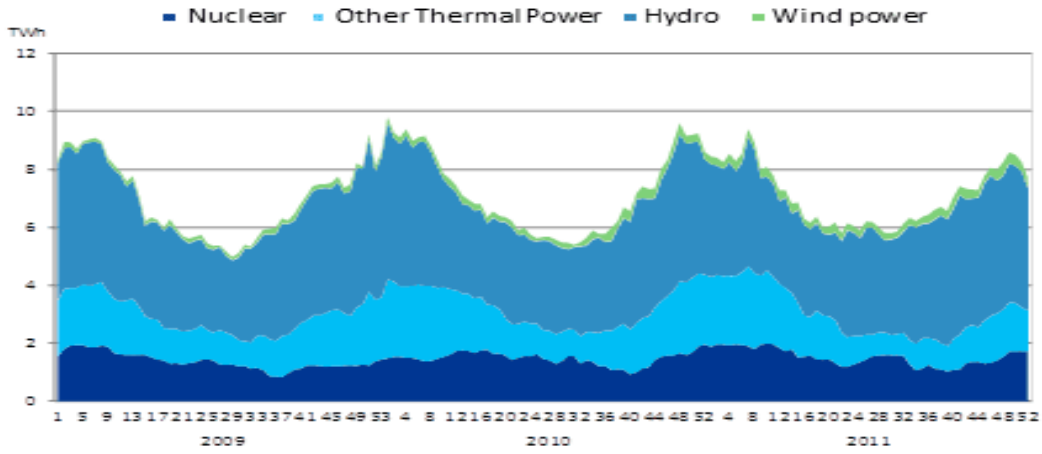
The Nordic electricity market

Sweden, Norway, Denmark and Finland together make up the integrated Nordic electricity market. It is considered to be the most efficient cross-border electricity market in the world (Karan & Kazdagˇli, 2011, p. 16). Despite having a relatively small combined population, the high level of per capita consumption means the Nordic electricity market is one of the major ones in Europe (Bergman, 2002, p. 51). The reason for the high consumption is that electricity prices in the Nordic countries have historically been low. As a result, electricity is extensively used for heating and a large electricity intensive industry has developed (NordREG, 2013). This industry is still very important for the economies of the Nordic countries and higher electricity prices will lead to decreased competiveness. In order to keep the energy intensive industries competitive and alleviate the extra costs incurred by the EU Emissions Trading schemes, these industries are to some extent subject to government support. As an example, in all of the Nordic countries except for Iceland, energy intensive industries receive a large portion of their needed emissions allowances for free. This support scheme is to decrease in magnitude in 2020 (Nordic Energy Research & International Energy Agency, 2013).

The Nordic electricity market is connected to Germany, Poland, Estonia, Russia and the Netherlands through interconnectors (NordREG, 2013). Efforts to further integrate the Nordic electricity market with other countries are ongoing (European integration – overview, n.d.).

Total power generation in 2012 was about 400 TWh and the generation mix is dominated by hydropower which constitutes of about half of the generation. The majority of the rest is made up of thermal and nuclear power. Recent years has seen an increase in the use wind power although the portion of it is still small. As the Nordic countries are to a large extent dependent on hydropower, dry years tend to result in increased imports from the previously mentioned interconnected countries (Producers, n.d.).

Figure 3. The Nordic countries' generation mix



(Producers, n.d.)

Prior to the 1990s the electricity markets in the Nordic countries were subject to tight regulation, as was the case in many other European countries. The industries were protected from foreign competition and dominated by vertically integrated publicly owned power companies. However, reforms and a new regulatory framework in the 1990s sought to establish a liberalized, integrated Nordic electricity market through measures such as the removal of border tariffs, opening up for competition in generation and supply and close co-operation between the different national transmission system operators (Bergman, 2002). Liberalization, by creating improved conditions for competition, was believed to facilitate better use of resources as well as operational efficiency increases (NordREG, 2006, p. 22). These reforms, along with the founding of a common power exchange, Nord Pool, have created a well functioning Nordic electricity market (Amundsen, Bergman & Fehr, 2006).

Electricity trade and the power exchanges in the Nordics and the United Kingdom

Nord Pool is one of the largest electricity power exchanges around, handling about 84% of all trade in the Nordics in 2013 (Trading and services, n.d.). In contrast, in the UK, power exchanges account for a relatively small share, as the bulk of the trading takes place bilaterally in the OTC markets through power brokers (Karan & Kazdag˘li, 2011, p. 20). This being said, the traded volumes at power exchanges in the UK are increasing. In 2011, the share was 15% of physical consumption, up from 4% in 2004 (Jaakko Karas, 2013). Nord Pool and the two power exchanges in operation in the UK, APX Power UK and N2EX are all members of the aforementioned North-Western Europe (NWE) day-ahead price coupling project that was launched in February 2014. Thereby, all three exchanges use the same price formation algorithm and harmonized operational

procedures (“Successful operation of PCR solution”, 2014).

A criterion for allowing the UK to participate in the NWE project was to have a common reference price. Earlier, this had not been the case, due to the existence of two power exchanges using different operational arrangements (“NWE day-ahead market coupling”, 2013). In order to enable a common reference price, a standard set of operational procedures as well as a platform connecting all interconnectors and power exchanges in the UK had to be developed. The platform, referred to as a “virtual hub”, allows the pooling of the exchanges’ liquidity, which enables the capacity of the UK’s interconnectors to be allocated by the NWE algorithm (“NWE day-ahead price coupling”, n.d.).

APX Power UK and Nord Pool Spot AS

APX Power UK and Nord Pool Spot AS, the two exchanges this thesis uses as data sources, offer similar electricity trading services such as day-ahead auctions and intraday trade. At the day-ahead auction electricity orders are placed for delivery the next day. Market prices for each hour the next day are calculated using supply and demand curves made up of electricity bids and offers. At Nord Pool AS, the auction facilitates reference prices in €/MWh for the Nordic countries, while at APX Power UK, a reference price is given in £/MWh for the UK (The day-ahead market – Elspot, n.d.; Auction, n.d.)

As the Nordic market consists of several bidding zones, there are two different types of prices of importance, the system price and the area price. The system price is used if there is no transmission congestion between zones. When congestion occurs and electricity flows are constrained between bidding areas, each area will get different prices, called area prices, that reflect regional market conditions (Bidding areas, n.d.). As previously seen, this is more specifically explained in the sections about zonal and nodal pricing and market coupling.

The intraday market offers continuous electricity trade, which helps balance supply and demand needs. This is important as incidents affecting supply can take place between the closing of the day-ahead market and the time of electricity delivery the next day. With increased dependence on intermittent renewable energy sources, such as wind power, intraday trade becomes more and more important (Intraday market, n.d.).

3. Literature review

This Literature review section will mainly focus on papers that study the integration of electricity markets in the light of what is of interest for this thesis, namely the welfare effects of integrating electricity markets and electricity trade. Market coupling, as the mechanism used in Europe to facilitate cross-border trade, will also be briefly touched upon. Additionally, since a growing portion of the recent literature is investigating electricity integration and its effect on the facilitation of increased use of renewable energy sources, we will also include a short overview of this literature.

Electricity integration, welfare effects and market coupling

Starting with the literature that quantifies the welfare effects of electricity integration, we conclude that such literature is quite scarce, which is line with what Newbery et al. (2013, p. 6) find. This section contains a selection of existing relevant studies.

Doorman & Frøystad (2013) analyse several aspects of the effects of different interconnection alternatives between Norway and Great Britain. A major distinction between Norway and Great Britain's electricity systems is the characteristics of their electricity generation structure. Norway's production is completely dominated by hydropower while Great Britain's uses primarily gas and coal, and as a consequence, prices are set differently.

The authors look at both the merchant investor profitability and the social welfare perspective of two different interconnections, one from southern Norway to southern Great Britain (England) and one from southern Norway to northern Great Britain (Scotland). Both these cases are analysed using two different scenarios, one using the actual structure of the electricity systems of 2010 and one using an assumed 2020 structure. The difference between them is mainly the increased dependence on wind power in the generation mix of 2020. A further issue investigated is the social welfare consequences of linking an interconnection between the two regions to an offshore wind farm.

In the scenario based on the 2010 electricity systems, Norway is a net importer of electricity. None of the interconnection alternatives were profitable from a merchant perspective, while both alternatives were profitable from a social welfare perspective. Of the two interconnection alternatives, the one to Scotland was the most beneficial. In the assumed 2020 structure, the use of

wind power grows in both regions as does hydropower in Norway. Electricity production increases dramatically in Norway while it decreases in the UK. As a consequence, there is generally excess supply while prices decrease and have less intraday variation. In this scenario Norway becomes a net exporter. In 2020 scenario, only the interconnection to Scotland is profitable and solely from a social welfare perspective. Regarding the link to the offshore wind farm, under the assumptions made, such a link is less profitable than a direct interconnection to Scotland. Hence, it is concluded, relying on merchant investments will not realize investments that increase social welfare.

Valeri (2009) studies the consequences of increased interconnection between Great Britain and Ireland. Ireland is a considerably smaller electricity producer than Great Britain and the two regions have different generation mixes. The largest share of Great Britain's production capacity is comprised of coal-fired generation while over half of Ireland's capacity consists of gas-fired generation (based on figures from 2005). These differences in generation technology lead to differences in average electricity prices, with Ireland being the more expensive region. More specifically, this paper's focus is on analysing the welfare effects of such interconnection, the capacity of the interconnection needed to merge the two markets into a single one and the impact on competition in the Irish electricity generation sector.

In short, the results of the welfare analysis show that Ireland generally gains, in particular Irish consumers, while Great Britain loses. In order to create a single market, the size of the increased interconnection will have to be in the range of 2000MW to 4000MW. When considering increasing future costs of carbon, resulting in coal generated power being less profitable, the difference between the respective regions' average electricity prices is reduced. Consequently, less interconnection capacity is needed in order to integrate the two markets. This implies that technological differences in the generation mix affects the gains from trade to a greater extent than differences in market size. Lastly, the capacity of the interconnection will have to be at least 1700MW in order to create a competitive Irish generation market.

Finon & Romano (2009) discuss electricity market integration from a consumer perspective. They look at what happens if low cost countries such as France, with nuclear as primal electricity technology, integrate with countries where electricity is produced with higher variable costs. They find that the price in France will increase, and this will not be offset by lower prices in other countries. Instead, decreased consumer surplus will be balanced with an increase in producer surplus. Finon & Romano view this as problematic. In a normal market, the increase in profit due

to higher prices will encourage more investment in the exported good. As a result of the complexity and insecurity surrounding nuclear power, there are however non-economic constraints that prevent more investments. The increased profits will hence accrue to producers as a "scarcity rent" and the result of market integration will be a reallocation of resources from consumers to producers. Finon &Romano (2009) argue that this scenario is likely in all countries that depend on electricity producing technologies that have low variable costs and where capacity extensions are unfeasible.

Billette de Villemeur & Pineau (2012) look at increased market access over different jurisdictions and their consequences upon price levels and the environment. They motivate the study as they deem there to be research lacking when it comes to explicitly illustrating the outcome of electricity market integration. The authors build on Billette de Villemeur & Pineau (2010), where it is shown that environmental externalities are likely to increase with electricity trade. As a consequence, market integration might not be welfare enhancing. In this paper, they move on to study the role of regulatory institutions in electricity market integration. They compare the effect of having different pricing structures, average cost pricing and marginal cost pricing, in the two trading jurisdictions under different institutional regimes.

In short, a model considering three different regimes is proposed. In regime 1 there are two jurisdictions, A and M, in autarky. Jurisdiction A has a monopolist where prices equal average cost through regulation and M is a competitive market, with prices equal to marginal cost. Regime 2 has trade between A and M through an unlimited interconnection while the pricing structures continue to be as regime 1. Regime 3 is fully integrated, characterized by unlimited trade and both jurisdictions setting prices at marginal cost. The assumptions made are that the industry is beyond the efficiency point and displays decreasing returns to scale, meaning average cost is assumed to be increasing. It is further assumed that the two jurisdictions, A and M, differ in their production costs and the environmental impact of their production technologies. Additionally, it is also assumed that the marginal costs are always higher than the average costs.

The results of Billette de Villemeur & Pineau (2012) show that only in regime 3, where both jurisdictions set prices at marginal, are the markets socially efficient. However, this is only true when any environmental impact is disregarded. With the environment accounted for, prices are too low.

The main conclusions of this paper are that marginal cost pricing in all jurisdictions is preferred.

Nevertheless, the authors highlight that there are a few caveats to consider. Namely, depending on the technology used for electricity generation, the impact on the environment varies. Also, price movements for the importing jurisdiction are ambiguous. In order to further evaluate these aspects, the authors request empirical studies to be conducted.

Førsund (2009) uses a stylized general equilibrium model of trade of electricity between two countries with different electricity generation. One country's electricity production consists of hydropower while the other uses thermal. A social planner perspective for cooperation between the countries is used to analyse the effects on prices and quantity of going from autarky to trade in a competitive market.

The conclusions of Førsund (2009) are that trade between the two countries leads to price equalization when interconnector capacity is unlimited. However, when there are constraints to the interconnection or when there are internal transmission constraints, prices are affected, with export prices being lower than import prices. As long as autarky prices between countries are different, there are in general gains by trade. Yet, as some industries and consumers might lose due to changes in electricity prices, in order to get acceptance of opening up electricity trade within the EU, the issue of welfare redistribution needs to be considered. Nevertheless, integration of electricity markets increases security of supply, which benefits all involved. In addition, Førsund (2009) emphasizes the importance of investing adequately in interconnector capacity in order to achieve price equalization between countries.

Parisio & Bosco (2008) analyse what happens to equilibrium bid functions derived by implicit auctions when an isolated domestic market opens up for cross-border trade. According to their estimations, cross-border trade may induce price convergence across countries. As a consequence, two parallel mechanisms reallocate gains and losses. As a result of an increase/decrease of demand and supply in each market, there is a "volume" effect. Interconnections lead to further modified bid functions causing a "bid effect". These effects can either contrast or reinforce each other.

Price adjustments caused by the "volume effect" are in line with standard trade expectations. However, the "bid effect" either reinforces or contrasts price convergence across countries according to demand, quantities and cost conditions. With an interconnection between a high-cost electricity producing country and a low-cost country, electricity flows from the low-cost area to the high-cost area and prices converge. As a consequence, consumers in the high-cost country gain at the expense of those in the low-cost one. At the same time, rent reductions for producers of the

importing country are offset by rent increases for producers located in the exporting country. Hence, gains and losses are reallocated across countries, which might explain the existence of opposition to the integration of the electricity markets of the EU (Parisio & Bosco, 2008).

Electricity integration and renewable energy

Moving over to papers about integration and renewable energy, a few findings will be presented. International policies have driven the growth of renewable electricity generation, with wind power being the dominating source. As wind power output is variable and unpredictable, increased interconnection has been emphasized as way of helping to facilitate wind power generation into electricity systems. To take an example, by connecting a region with large amounts of wind power to one that has flexible generation sources, the variable wind output can be balanced when needed. This would reduce the necessity of both regions having excess flexible capacity. If both regions have wind power, an interconnection will give greater geographical spread of that variable production resulting in reduced overall fluctuations of output. In other words, the larger, combined geographical areas will be more likely to have favourable weather conditions somewhere within its region. Hence, increased interconnection will lead to increased security of supply (TradeWind, 2009). In the report by Newbery et al. (2013, p. 21), it is concluded by summarising previous research that integrating electricity markets enables greatly increased use of renewable electricity sources without having to improve the existing electricity grid. As a consequence, the system costs associated with implementing the amount of renewable energy sources that current European policies require are reduced.

An example of a paper where renewable energy and market integration is studied is Schaber et al. (2012). They look at the challenges associated with expanding variable renewable energy sources, such as wind and solar power, in Europe. As the volume of electricity generated by wind and solar power is unpredictable and varies greatly, increased dependence on these sources requires large amounts of excess generation capacity to make sure demand and supply always match. There are also issues concerning the occurrence of overproduction. Schaber et al. (2012) find that extensions of the electricity grids and increased inter-linkages lessen the aforementioned problems as it smoothens the fluctuations of wind and solar power. An enlarged interconnected geographical area increases the chances of adequate wind or sun somewhere, enabling areas with overproduction to transfer electricity to deficit areas. Finally, the authors concede that even though these types of grid extensions decrease the need of backup capacity, flexible excess capacity will still be important, as the problems with the fluctuations of renewable energy will, to some extent, continue.

Another example is Denny et al. (2010) who look at the effects of added interconnection capacity between Ireland and the UK. The Irish electricity system is relatively more expensive than the one in Great Britain and both regions are increasing their investments in wind power. Denny et al. (2010) do several simulations that investigate the effects of improved interconnection between Ireland and Great Britain. A base case using an assumed 2020 scenario with increased wind generation is compared to four scenarios: one with increased interconnector capacity between Ireland and Great Britain (from 1000MW to 2000MW), one with greatly increased wind generation in Great Britain, one that looks at the intra-day trade and one that looks at the impact of a transmission constraint between Scotland and England/Wales on the connection between Ireland and Great Britain. The last three scenarios also assume an interconnector capacity of 2000MW. Without going into detail, the main findings of their simulations suggest that added interconnector capacity would reduce both price fluctuations and average prices in Ireland. While net total emissions would be unchanged without an adjustment in the assumed 2020 scenario's generation mix, the production of emissions can shift from the relatively more expensive Irish system to the cheaper system of Great Britain. An increase in interconnection capacity is found to considerably improve system security while intra-day scheduling of the interconnectors should further reduce average prices and price variability. Finally, it is suggested that, having a transmission constraint between Scotland and England/Wales would not have a significant impact on the electricity generation in Ireland, instead imports and exports to and from Ireland would increase as the country would act as a "transmission corridor".

4. Purpose and motivation

According to the EU there are many benefits with increased integration of the electricity markets of Europe. Cross-border trade of electricity is expected to lead to increased competition in generation and supply giving consumers more choices and lower prices. Electricity companies will be given the incentives to invest in new generation and infrastructure based on market conditions and not subsidies. The internal market will be better at accommodating renewable electricity sources and there will be increased security of supply (European Commission, 2012).

As previously seen in the Literature review section, there are overall benefits from integration and it does promote increased use of renewable sources. This is also in line with economic theory as will be discussed further down. However, according to theory as well as research, trade results in welfare redistribution both between and within countries. Certain groups will expect to be worse

off, and as a consequence oppose additional integration. The uncertainty regarding the scope and the direction of gains and losses from trade requires further research.

In this thesis we aim to contribute to the literature concerning the effects of electricity trade between different regions. In our case, we have chosen to investigate the effects of trade between the high cost electricity market of the UK and the low cost ditto in the Nordic countries. We will explore the effects of trade on electricity prices from a welfare perspective by analysing how consumers and producers in each region are affected. Several aspects of trade will be examined by having different scenarios where changes to the structure of the generation technology are made.

Even though electricity in the UK, on average, is more expensive than in the Nordic countries, as there is a variable aspect of certain production technologies trade might not always flow from the Nordic countries to the UK. This differentiates electricity trade from other types of trade. As this is the case, investigating different cases where there are changes in available production technologies is important in order to better understand electricity trade patterns.

Comparison to Doorman & Frøystad (2013)

The paper by Doorman & Frøystad (2013) has already been described in the Literature review section, however, a closer examination of it and a comparison to what we aim to do is entitled.

The results of their 2010 scenario show that Norway is a net importer of in excess of 5 TWh. The effect on prices in Southwest Norway (where the interconnection in Norway is situated) is that they decrease in all cases. With an interconnection to the south of the UK, prices there go down slightly, while with one to Scotland prices are more or less unaffected.

Comparing these results to the ones we hypothesize further down reveal they are far from corresponding. There are several possible explanations to this, not in the least as this thesis and the paper by Doorman & Frøystad (2013) use different models, assumptions and scenarios. Instead of studying the effects of an interconnection between the UK and Norway, this thesis looks at the UK and the Nordic countries. We assume each region to be a single integrated electricity market with no internal transmission congestion while they consider the existence of congestion.

Analysing a connection to the Nordic countries, when these are considered to be a single electricity market, instead of solely Norway provides a different case. Norway's electricity generation is almost completely made up of hydropower while the Nordic countries as a whole have quite a

different generation mix. Although hydropower is still the dominating power source, a considerable portion consists of nuclear and thermal power. As a consequence of having differences in the generation mix, the cost structure in the Nordic countries is dissimilar to the one in Norway.

Another important aspect that differentiates this thesis is that the year 2010 was a year of drought in Norway. As a result, prices were higher and domestic production was lower compared to an average year. As a comparison to 2010, the year 2012 this thesis uses was a year when prices in the Nordic countries were at a more average level. Therefore, using 2012 as a reference year might show different trade patterns compared to using 2010 as hydropower supply can vary depending on the year and water levels.

Research Questions

In this thesis we aim to investigate the welfare effects of integrating the high-cost electricity market of the UK with the low-cost one of the Nordic countries. More specifically, in order to do so, we seek to answer the following questions:

How are electricity prices affected by electricity trade between these two markets?

How does electricity trade affect the welfare of consumers and producers in each region?

How are trade patterns affected by differences in the characteristics of generation technology as well as differences in the production mix?

In order to help us answer these questions we will run seven different scenarios.

Scenarios

Scenario 1: Base case

Since we wanted to look at the electricity markets of today, our base case uses data from 2012, the most recent year where comprehensive data of the electricity markets for both regions was available. Another factor that played in was that 2012 was, more or less, an average year when it comes to hydro production and prices in the Nordic Countries. In table 2 further down, the production mixes of the base case are presented.

Scenario 2: Dry case

The dry case scenario is based on the same input variables as the base case, with one exception. We have used the hydro production of 2010, the driest year since 2006 in order to investigate the effects of a reduction in hydropower. As hydropower is the dominating source of electricity in the Nordics, how a shortage might affect prices and consequently electricity trade is of interest. In this case, the Nordic hydro production is 17% lower than in the base case. Since hydropower in the UK only consists 2% of total generation, it is left unchanged.

Scenario 3: Norway - UK dry case

We will also analyse effects of an interconnector between the UK and Norway. By using the hydro production of 2010, this scenario enables a comparison with the paper by Doorman & Frøystad (2013). Since Norway is to a large extent integrated with the other Nordic countries, we also use these countries respective prices from 2010. As this thesis and Doorman & Frøystad (2013) use different models, the cases are not exactly corresponding. However, we will still get an idea whether or not our results point in the same direction as theirs.

Scenario 4: Norway – UK base case

Our second Norway scenario is based on 2012, a year where conditions for hydro production were more normal. Therefore, hydro generation is in this case 22% higher compared to 2010. This scenario is included in order to see if Doorman & Frøystad's (2013) results hold when hydro production is higher.

Scenario 5: More wind case

This scenario is based on the 2012 structure. However, both the UK and the Nordic countries have increased their installed wind power capacity. This scenario assumes that the two regions reach their 2020 environmental targets and that all increases in renewable energy sources consist of solely wind power. In the UK, wind power increases from 6% of yearly production in the base case to 28%. In the Nordics, fulfilling each country's 2020 target results in wind having a 15% share of their combined yearly production, compared to 5% in the base case.

Scenario 6: More wind less nuclear case

This scenario is similar to scenario 5. However, in order to reduce the amount of excess supply that is the result of the increased wind power in the Nordic countries, we have assumed that all Swedish nuclear plants are dismantled. The loss of electricity generation corresponding to the decrease in nuclear power is in excess of the increase in wind power by 13 TWh. In the Nordic market, prior to the interconnection to the UK, this implies that increased amounts of fossil fuel generation will have to be used compared to the base scenario. Even though Vattenfall AB is investigating the prospect of building new nuclear facilities (Consulting early on Swedish new nuclear build, 2014), Sweden is more likely than Finland (the other nuclear-producing Nordic country) to end nuclear production, as Finnish plants are newer (Nuclear power in Finland, 2014). In the UK, the increased wind power does not result in excess supply as the UK can compensate by a reduction in fossil fuel generated power.

Scenario 7: Specialization in both countries

The final scenario disregards national renewable targets. As previously taken up in the Literature review, having increasing shares of intermittent energy sources such as wind and solar power needs to be supplemented by flexible electricity production such as coal and gas fired generation. In this scenario we assume that the Nordic countries have a comparative advantage in wind-powered generation while the UK has so in flexible electricity production such as coal and gas generation. Wind power in the Nordic countries is increased to the same level as in scenario 5 and nuclear power is reduced to the level of scenario 6. Their advantage is in the form of lower costs of building wind farms. The UK is assumed to have increased efficiency in its coal and gas power plants compared to the base case, subsequently leading to lower production costs. As a result, the two regions can complement each other and increase their overall share of renewable energy sources. This may not be a very realistic scenario but it is interesting from a discussion point of view.

Table 2. Production mix, Base case

UK

Technology	Installed capacity 2012 (MW)	Production 2012 (MWh)	Share of total production
Conventional power	33 713	158 823 549	46%
Gas turbine	35 320	94 079 857	27%
Nuclear	9 946	63 949 205	19%
Hydro (excluding pumped storage)	1 549	5 249 671	2%
Wind and other renewable	7 060	20 775 449	6%
Total	**87 588**	**342 877 730**	**100%**

Nordics

Technology	Installed capacity 2012 (MW)	Production 2012 (MWh)	Share of total production
Conventional power	7 407	8 909 963	2%
Closed cycle gas turbine	4 121	12 000	0%
CHP, industry	5 152	16 942 192	4%
CHP, district heating	13 523	40 353 710	10%
Nuclear	12 021	83 456 000	21%
Hydro (excluding pumped storage)	49 836	237 906 476	58%
Wind and other renewable	7 754	19 496 760	5%
Total	**99 814**	**407 077 102**	**100%**

5. Theoretical framework

A Partial equilibrium model for the electricity market

Before discussing how trade will affect the electricity markets, we have to go through some basic assumptions regarding how the electricity market functions in autarky.

In this paper, the electricity market is assumed to be characterized by perfect competition. This is an assumption that is common but not undisputed[1]. A common way of studying the price setting mechanism on markets where perfect competition is prevalent is using the partial equilibrium model. In that model, the market for one good is analysed with all other markets regarded as exogenous (Krugman, Obsfeldt & Melitz, 2012, p. 30). In reality, markets interact and studying one market in isolation is therefore a substantial simplification. Nevertheless, this simplification is necessary in order to illustrate how the electricity market reacts to trade. Using a partial equilibrium model will however not capture all welfare effects, something we will address further on. With certain assumptions and adjustments presented below, the partial equilibrium model will

[1] The electricity market has some problems with market power and high entry barriers (see for example European Commission (2007) for further details). However, as researchers often assume perfect competition when simulating electricity markets (Doorman & Frøystad, 2013), we deem it reasonable to do so.

however provide an estimate of how prices and quantities in the electricity market will change as a consequence of opening for trade with a new market.

Basic assumptions

We assume two countries. Both countries have deregulated markets where prices are set at spot auctions. We assume that no congestion exists in the internal markets. Further, we assume that there is no intraday market, hence the demand has to be met by supply in the spot market in order to avoid blackouts.

In both countries, there are two types of actors; consumers and producers. Consumers have identical preferences in both countries. Producers, on the other hand, differ in terms of cost structure. Although electricity is a completely homogenous good, it can be produced by many different technologies that have different costs. In our model, one country has a higher capacity in cheaper production technologies and thus, lower costs. As a result of the difference in cost functions, prices will differ between the two markets, which create incentives for trade.

Demand

Demand of electricity is a function of price and several other variables that are exogenous to this model, for example income, weather and time of the day. Demand for time *t* is given by:

$$D_t = f(\theta_t, p_t)$$

where p is price and θ is a vector of other variable values at time t.

The relationship between price and quantity demanded for a good is determined by the price elasticity of the good, e.g. how much consumers are willing to reduce their consumption if the price is raised with one per cent. In the very short run (hourly), electricity consumption is difficult to reduce and can be said to be completely inelastic. In the longer run, electricity intensive industries can shut down and private consumers can adopt to use more energy efficient technologies. The Nordic Council of Ministers (2008) estimate the short-run consumer price elasticity of electricity demand to be -0.35 and the long-run to be -0.75. Their figures are based on

previous studies and they state that as modelling elasticity demand is very complex, the numbers should be seen as rough estimates (Nordic Council of Ministers, 2008, p.81)[2].

When looking at the electricity market hour by hour, assuming complete inelasticity is reasonable. When comparing before and after trade is introduced, it is intuitive to think that consumers make predictions of how prices will evolve after trade and adjust their consumption in accordance with their expectations. Then, it would be appropriate to assume some price elasticity. However, since the potential decrease in consumption in that case would be based on expected price differences rather than actual we find it very hard to estimate an appropriate value for the elasticity. We therefore also choose to use completely inelastic demand when comparing before and after trade in order to simplify our model.

With inelastic demand, we end up with the following demand function:

$$D_t = f(\theta_t)$$

The supply curve

What distinguishes the electricity market from other markets is that electricity is produced at very different costs. Normally, high cost technologies will be out-competed by low cost ones. For electricity however, the use of low cost technologies is restricted because of natural or political constraints. Using these technologies only will therefore not meet demand. Thus, in hours where demand is high, more expensive technologies have to be used.

What also characterizes the electricity market is that both demand and supply are very dependent on exogenous factors such as weather. The dependence on exogenous factors has a very important implication – it results in a different shape of the supply function for each hour. As will be seen, this has implications for the effects of trade.

We assume k different technologies which each having a maximal capacity $M(\theta_t)_i$ where θ is a vector of other variable values at time t, fixed costs F_i and a variable cost c_i. If they are ordered such that technology i is the cheapest and technology k the most expensive, the cost function for each producer j generating quantity Q is as follows:

[2] As a comparison, Madlener, Bernstein & González (2011) find, when studying consumers in 18 OECD countries that the short-run elasticity is -0.1 while the long-run is -0.4. They also look at industrial sectors in Germany and find the short-run industrial elasticity to be between 0 and -0.57 while the long-run is between 0 and -0.52.

$$C(X) = c_1Q_1 + c_2Q_2 \ldots\ldots + c_kQ_k + \sum_{i=1}^{i=k} F_i$$

where Q_i is the quantity produced with respective technology.

All firms are profit maximizing and their profit is given by

$$\pi = \sum_{i=1}^{i=k} (p - c_i)Q_i - \sum_{i=1}^{i=k} F_i$$

the constraint $X_i \leq M\ (\theta_t)_i$ must also hold for each technology.

Profit is maximized when

$$\frac{d\pi}{dQ_i} = \sum_{i=1}^{i=k} (p - c_i) = 0$$

Hence, the supply curve is determined by the marginal cost of each technology. We assume every producer to have a portfolio of technologies that will be used in merit-order starting with the cheapest. This yields a stepwise increasing curve where the price for a certain demand is set at the marginal cost of the last technology introduced.

For:

$0 \leq Q \leq M(\theta_t)_1, \qquad P_t\left(Q_{S_t}\right) = c_1$

$M(\theta_t)_1 \leq Q \leq M(\theta_t)_2, \qquad P_t\left(Q_{S_t}\right) = c_2$

$\vdots$

$M(\theta_t)_{k-1} \leq Q \leq M(\theta_t)_k, \qquad P_t\left(Q_{S_t}\right) = c_k$

The result of the above is that the supply curve is convex. Supply for a certain hour is hence given by:

$S_t = f(\theta_t, p_t),$

$S_t'(\theta_t, p_t) \geq 0$

where p is price and θ is a vector of other variable values at time t.

As will be described in more detail in the method section, we have several production technologies where *c* is zero. We also have conventional power and gas turbines with a positive marginal cost that is exactly determined by the efficiency in each power plant. Hence, the steps will be very small in parts of the supply curve. In order to simplify our analysis, we made these parts linear.

Figure 4. The supply curve



Determining equilibrium price

In equilibrium, supply equals demand and price equals marginal cost. Neither consumers nor producers have incentive to change their economic decisions.

Partial equilibrium model with trade

As stated above, our countries have different allocations of production technologies and as a consequence different prices. We assume both markets to have the same currency. According to theory, the effect of trade will be that the prices in both countries converge and that some production moves from the high cost to the low cost country (Krugman et al., 2012, p. 144). Since the supply curve for electricity unlike many other goods is convex, there is diminishing return to scale. This limits the extent to which production shifts from one country to another. Even if the price difference initially is very high, we will never see the case where all production takes place in the low cost country.

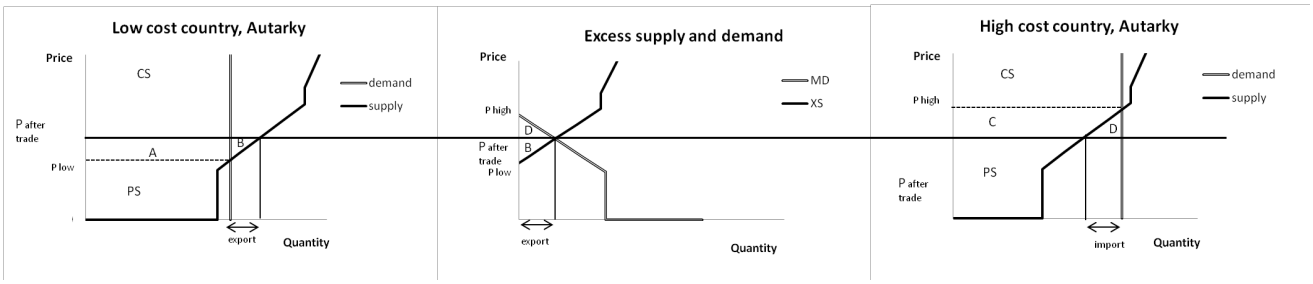
When the markets open for trade, the producers in the low cost country *i* face a higher price when they export and want to export until this price meets their marginal cost. In the high cost country *j*, consumers are now able to import to a lower price. Since demand is inelastic, they replace some domestic consumption with imports (Krugman et al., 2012, p. 193). We do now get two new curves, export supply, XS, and import demand, MD.

$$XS_t = S_{ti}(\theta_{ti}, p_{ti}) - D_{ti}(\theta_{ti})$$

$$MD_t = D_{tj}(\theta_{tj}) - S_{tj}(\theta_{tj}, p_{tj})$$

With unlimited trade, the price will eventually be similar in both countries. The new price will be where export supply meets import demand (Krugman et al., 2012, p. 195). Some production will be reallocated from the high cost country to the low cost one so that prices again equal marginal costs in both countries.

Figure 5. Effects of trade

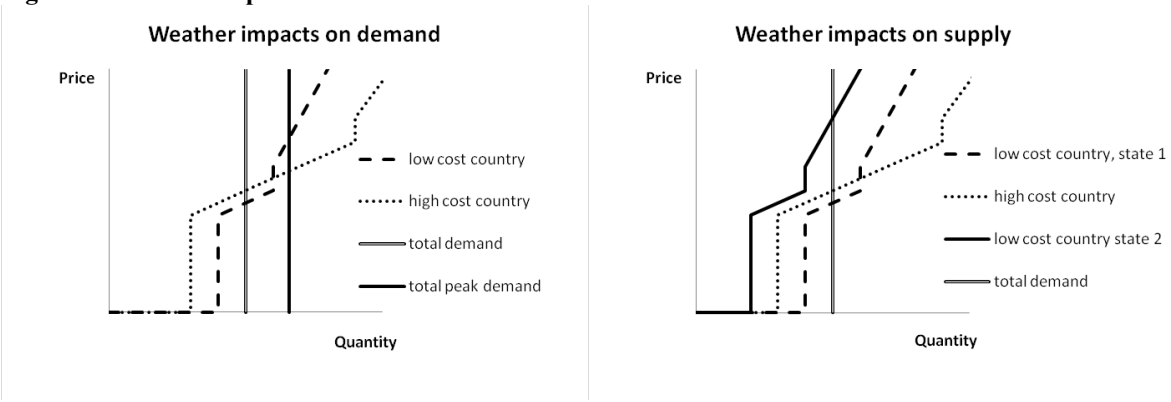


When discussing welfare gains from trade, it is common to talk about consumer surplus (CS); the sum of what all consumers are willing to pay minus what they have to pay, and producer surplus (PS); the sum of all producers' revenues minus their costs (Krugman et al., 2012, p. 198). In this case, the effects of trade for the low cost country will be that prices will increase resulting in welfare redistribution from consumers to producers (Area A). Since the increase in PS is larger than the decrease in CS, there will be a net gain (B). In the high cost country, the effect will be the opposite, PS decreases with C while CS increases with C and D. D is then the net gain in the high cost country. With inelastic demand, CS is infinitely large. However, we assume consumers still consider a decrease in CS as negative.

As mentioned above, the supply curve is dependent on exogenous factors. More specifically, these factors, the most important being the weather, determine the maximum production capacity for a technology in a certain hour. The weather dependent technologies are those with zero marginal cost. With unfavourable weather conditions, the cost curve will therefore shift to the left. This shift could turn the previously described scenario to the opposite implying that the low cost country now is the high cost country and hence the net importer. This can be seen in the right hand graph below. In state 1, that is the normal state, the low cost country has lower costs and will export. In state 2 however, the decrease in low cost technologies yields higher costs for the low cost country implying that this country will import. In the left hand graph, we instead study variation of

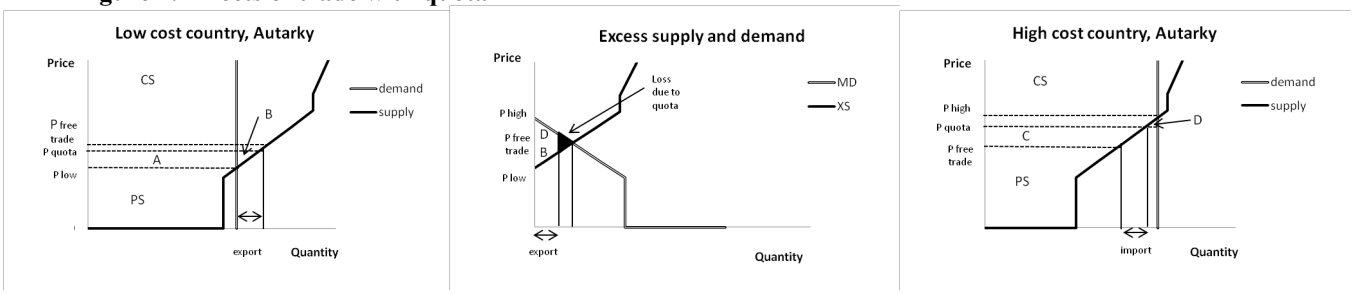
demand. When there is a peak in aggregated demand, the high cost country has more advantageous production technology as they have more of the second cheapest source. Hence, trade will take the opposite direction. To conclude, the effects of trade could be very dissimilar for different hours. The aggregated yearly effect depends on which hours are more prevalent. In this case, state 2 and peak demand occur less often and the low cost country will be the net exporter on a yearly basis.

Figure 6. Weather impact



Electricity can only be transported and traded through an interconnector between the countries. The interconnector will act as a natural quota, limiting the amount of trade for a given time period. If the desired export/import exceeds the maximum capacity of the interconnector, the prices cannot fully converge and the full benefits from trade cannot be reaped. As can be seen in the graphs below, the net gains (D and B) are now smaller (Krugman et al., 2012, p. 207).

Figure 7. Effects of trade with quota



As a consequence of prices not fully converging, some quantity of electricity (equal to the maximum interconnector capacity) can be produced at low cost in one country and sold at a high price in the other. This creates congestion rent.

The congestion rent can be dealt with in different ways. Assuming that the producers sell their electricity directly to the consumers and that the producers themselves build the cable, the producers that export will get the congestion rent. If the governments are in control of the interconnector, the rent can also be used to compensate the groups that lost due to the opening of

trade. A third option is to assume that a third party builds the interconnector. In that case, the congestion rent is the return on this third party's investment.

The congestion rent increases with the volume traded. But, simultaneously, increased trading volumes decrease the price difference between the countries and hence decrease the congestion rent. Therefore, an optimum cable size exists and for unlimited trade to be available, the party that gains from trade needs to contribute to the investment.

In our scenario, we chose the first option and included the congestion in the producer surplus which makes it reasonable to think that the producers should fund the cable. Estimating the investment cost for the cable is however out of scope for this thesis.

6. Hypothesis

Based on earlier literature and theory, we expect the following answers to our research questions:

How are electricity prices affected by electricity trade between these two markets?

Prices will partly converge. The UK (the high cost country) will get a lower price level and the Nordics will get a higher.

How does electricity trade affect the welfare of consumers and producers in each region?

The aggregated yearly effect will be that the Nordics are the net exporters. Nordic producers will therefore gain from trade while consumers lose. In the UK, the redistribution pattern will have the opposite direction.

How are trade patterns affected by differences in the characteristics of generation technology as well as differences in the production mix?

This question will be answered by looking at our different scenarios:

- Base case: The Nordics are the net exporters.
- Dry case: The reduction of hydropower in the Nordics makes the countries more similar to each other before trade. Compared to the base case, the magnitude of the redistribution and welfare gains would therefore be smaller. However, we do not think that the reduction in

hydro production will be enough to increase Nordic prices above those in the UK. Hence, the Nordics will still be the net exporter.

- Norway-UK dry case: As hydro production is such a high share of Norwegian electricity generation, we expect results in line with Doorman & Frøystad (2013). That is the UK being the net exporter.
- Norway-UK base case: Here, we expect to see the opposite result compared with Doorman & Frøystad (2013) implying that Norway is the net exporter.
- More wind scenario: Higher dependence on intermittent technologies should lead to higher gains from trade since the countries can balance supply and shortages with each other instead of using more expensive fossil fuels. Since the Nordic production from inflexible sources (wind, hydro, nuclear and CHP) will be very high with excess supply as a consequence, we expect very low prices in the Nordics who will be the net exporter.
- More wind, less nuclear: The reduction in nuclear power will make the countries more similar compared to the base case. We therefore expect lower welfare gains and redistribution compared to the base case. However, we expect higher gains than in the dry case due to the higher share of wind power.
- Specialization: If the countries are allowed to specialize, we expect trade will to a large extent go in both directions. Since the Nordic countries still have more of the cheaper production sources, we still expect the Nordics to be the net exporter.

7. Method and data

The impact of trade is simulated in a model built on data from 2012. First, each country is modelled as a separate market. Prices and quantities of 2012 are used as benchmarks for these models. We then connect the two countries and enable limited trade through a 1400 MW interconnector. By increasing the maximal capacity of the interconnector, we also see what happens when free trade is facilitated. Since demand and supply to a large extent depend on season and time of the day, we model each hour separately.

The Nordic countries are in our analysis viewed as a single market with a common single price. This does not exactly correspond to actual conditions since there are many hours where there are congestions and thus different area prices. Future investments however aim to reduce these differences by removing bottlenecks (European Commission, 2013). Also, going into the data from 2012, it can be seen that on average, actual price variations between bidding areas were small.

Looking at the effects of trade in hours where there is congestion, the effect on price would be larger in areas closer to the interconnector while lower further away. However, the average effect on the whole Nordic region would probably still be the same. When calculating the welfare effects from trade in the whole Nordic market, using a single price is therefore reasonable.

Estonia became part of the Nordic market in 2012. Since we lack essential production data about Estonia, and since Estonia constitutes the smallest and least integrated part of Nord Pool, we chose to exclude it from our calculation.

In the model, price is set through an iteration loop such that supply and demand matches for each hour. Demand is exogenous. Supply consists of electricity produced by different technologies. Some produce independent of price and are endogenous in the model. For others, the production volume is determined within the model. There are two countries in the model; *i* and *j,* and 8784 hours *t* (2012 is a leap year).

The algorithm for country *i* hour *t* before an interconnector is built is as follows:

$$0 \leq D_{ti} - S_{ti}(p_{ti}) \leq 100$$

Where

$$S_{ti} = W_{ti} + N_{ti} + CHP_{ti} - T_{old}\left(p_{ti}, p_{tf}\right)_{ti} + H_{ti}(p_{ti}) + F_{ti}(p_{ti})$$

After the interconnector is built, the algorithm is as follows:

$$0 \leq D_{ti} - S_{ti}(p_{ti}) \leq 100$$

Where

$$S_{ti} = W_{ti} + N_{ti} + CHP_{ti} - T_{old}\left(p_{ti}, p_{tf}\right)_{ti} + H_{ti}(p_{ti}) + F_{ti}(p_{ti}) + T_{new}\left(p_{ti}, p_{tj}\right)_{ti}$$

$$T_{new}\left(p_{ti}, p_{tj}\right)_{ti} \leq |\gamma|$$

Each part of the algorithm and the data used is explained below:

Demand (D)

In order to capture the season and day variation of demand, we use historical consumption per hour for 2012 as our data. This is reasonable since demand in the very short run can be said to be completely inelastic. We will later discuss whether 2012 was a normal year when it comes to temperature, a very important factor for determining demand.

Supply (S)

To meet a given demand, different production technologies will be used. Wind, nuclear and CHP produce independent of price while the use of fossil and hydropower is determined by price. We have also included the existing trade to other countries as a production technology. Technologies that contribute to overall production to a very small extent, solar power in all countries and CHP in the UK, are excluded.

Wind power (W)

Wind power has a marginal cost of zero and each firm will use as much wind as possible every hour. However, the use of wind is restricted by weather. We assume wind conditions to be random. For each hour, the maximum capacity is therefore multiplied with a random number between 0.1 and 0.9 (the state where more than 90 per cent or less than 10 per cent of wind turbines are running at full capacity is presumed to be very unlikely). When comparing with the actual production of 2012, our modelled production was considerably higher. We therefore multiplied the hours with random numbers >0.5 with a new random number. This gave us a total production similar to that of 2012.The randomization is done separately for each country and each scenario but the same randomization is used when comparing before and after the cable is built for each scenario.

$$W_{ti} = r_{ti1} * \frac{Wcap}{8784}\,, \qquad for\ r_{ti1} \leq 0{,}5$$

$$W_{ti} = r_{ti1} * \frac{Wcap}{8784} * r_{ti2}\,, \qquad for\ r_{ti1} > 0{,}5$$

$r_1, r_2 \in [0.10, 0.90]$

Nuclear power (N)

Because nuclear power plants are very expensive to pause and start up, the marginal cost for producing an extra unit is zero in the short run. Nuclear power plants are hence assumed to be constantly running. However, it is unlikely that all reactors are able to run at full capacity all the

time. We therefore introduce a random factor in nuclear production and using the calculation below provides a total production similar to that of 2012.

$$N_{ti} = r_{ti} * \frac{Ncap}{8784}, \qquad r \in [0.65,0.95]$$

Combined heat and power (CHP)

In the Nordics, thermal power is used both for district heating and in the industry. Since electricity is a by-product in heat production, CHP has zero marginal cost. There are two different types of CHP, industry and district heating. Industry CHP is assumed to be constantly running while CHP from heating is only used during cold periods.

$$CHP_{ti} = \frac{CHP\ ind}{8784}\ for\ 2171 < t < 6636$$
$$and = \frac{CHP\ ind}{8784} + \frac{CHP\ heat}{4464}\ for\ other\ t$$

Hydropower (H)

Hydropower is very important for the Nordic countries while only used to a small extent in the UK. The marginal cost for producing hydropower is basically zero but the production volume for each year is limited and dependent on weather conditions. Since producers of hydropower are able to store the water, they can adjust the production volume for each hour in a way that maximizes their revenues. Hydropower can therefore smoothen price variations. When prices are high, hydropower-producing firms will produce as much electricity as possible with lower prices as a consequence. When prices are low, they store the water in order to use it later when prices are higher. In our model, the producers can determine the exact volume to produce within a certain interval. The limits of this interval are based on the Norwegian production for 2012. Since almost all of Norway's electricity is generated by hydropower, the minimum and maximum hourly production divided by installed hydro capacity constitutes a good proxy for the lowest and highest share of hydro capacity that it is possible to use in one hour. Within the above mentioned interval, the hourly production is a function of price. The maximum and minimum accepted price is set such that total production matches a benchmark production (2012 or 2010) but also such that the revenues of the producers are maximized.

$$H_{ti}(p_t) = prod_{min} + \max\left(0; \min\left(prod_{max} - prod_{min}; \frac{p_{max} - p_{min}}{p_{max} - p_{min}} * (prod_{max} - prod_{min})\right)\right)$$

Where

$prod_{min} = minimal\ production$
$prod_{max} = maximal\ production$
$p_{min} = minimum\ accepted\ price$
$p_{max} = maximal\ accepted\ price$

Existing trade (T_{old})

Both the Nordic and the UK markets are already connected to other markets. In the model, we have only used the interconnectors that are price coupled to the spot markets (Nord pool and APX Power UK) since these connections are important for the price formation. For the Nordics, that includes connections to Germany and the Netherlands and for the UK, France and the Netherlands. The UK is also connected to Ireland but since Ireland is a considerably smaller market than the UK, the Irish price is more likely to be affected by the British than vice versa.

If prices are higher in the foreign country *f*, our model exports the highest of the maximum transmission capacity and the amount needed for prices to be approximately the same. If prices in the home country are higher, the opposite reaction will take place.

$$T_{fi}(p_{ti}, p_{tf})_{ti} = \min\left(maxcapEX_{tif}; \frac{(p_{tf} - p_{ti})}{a} * maxcapEX_{tif}\right)\ for\ \ p_{tf} > p_{ti}$$

$$T_{fi}(p_{ti}, p_{tf})_{ti} = -\min\left(maxcapIM_{tif}; \frac{(p_{ti} - p_{tf})}{a} * maxcapIM_{tif}\right)\ for\ \ p_{tf} < p_{ti}$$

$$T_{fi}(p_{ti}, p_{tf})_{ti} = 0\ for\ \ p_{tf} = p_{ti}$$

$$T_{old}(p_{ti}, p_{tf})_{ti} = \sum_{f=1}^{f=2} T_{fi}(p_{ti}, p_{tf})$$

Where

$p_{tf} = price\ in\ foreign\ country\ 1\ or\ 2$
$maxcapEX_{tif} = maximal\ interconnector\ capacity\ for\ export\ between\ f\ and\ i$

$maxcapIM_{tif} = maximal\ interconnector\ capacity\ for\ importbetween\ f\ and\ i$

$a = a\ constant\ enabling\ the\ iteration\ process$

Fossil (F)

Fossil power includes conventional steam power and power from gas turbines. Conventional steam power is power generated from the condensing of coal and other fuels such as biomass. Since we lack data about the extent and type of bio fuel used, we assume that only coal is used. This is reasonable since the total amount of bio fuel is so small that it does not have a considerable affect on price. In gas turbines, natural gas and to a lesser extent oil is condensed. The marginal cost of using fossil power is the price of fuel and CO^2 emissions. This cost is different for different power plants depending on the fuel in use and the varying efficiency of the power plant. Fossil fuel is used only when demand is not completely met by the sources with zero marginal cost. Conventional steam is notably cheaper than using gas turbines and will hence be prioritized. In our model, we have a maximal capacity for conventional steam power and gas turbines respectively based on the actual installed capacity 2012. The amount produced by each technology is then set by the iteration loop. We assume costs to increase with quantity in an interval given by fuel prices 2012 and the efficiency of Danish power plants. A more detailed description of how we calculated the cost intervals can be found in Appendix 1.

$$F_{ti}(p_t) = Conventional_{ti} + Gas\ turbine_{ti}$$
$$Conventional_{ti}(p_t) = 0\ if\ p_t < cost_{min}$$
$$Conventional_{ti}(p_t) = \min\left(prod_{max};\ \frac{p_t - cost_{min}}{cost_{max} - cost_{min}} * prod_{max}\right)\ \ if\ p_t \geq cost_{min}$$

Where

$prod_{max} = maximal\ production$
$cost_{min} = minimum\ marginal\ cost$
$cost_{max} = maximum\ marginal\ cost$

Production from Gas turbines is calculated in a similar way with other values of costs and maximal production.

New trade (T_{new})

Trade associated with the new interconnector is calculated in similar a manner as $trade_{old}$. The difference is that the price of the foreign country is endogenous and dependent on the volume imported or exported. The interconnector capacity is assumed to be the same in both directions and for all hours. In the free trade model, the interconnector capacity is set sufficiently high so that it is never congested. In the limited trade model, the capacity is set at 1400 MW, which is the capacity of one of the planned interconnectors (NordREG, 2013).

$$T_{new}(p_{ti}, p_{tj})_{ti} = \min\left(\gamma; \frac{(p_{tj} - p_{ti})}{a} * \gamma\right) for\ p_{tj} > p_{ti}$$

$$T_{new}(p_{ti}, p_{tj})_{ti} = -\min\left(\gamma; \frac{(p_{ti} - p_{tj})}{a} * \gamma\right) for\ p_{tj} < p_{ti}$$

$$T_{new}(p_{ti}, p_{tj})_{ti} = 0\ for\ p_{tj} = p_{ti}$$

Where

$\gamma = maximal\ interconnector\ capacity\ for\ export\ and\ import$

$a = a\ constant\ enabling\ the\ iteration\ process$

Calibration of the model

In the base case, all exogenous inputs to the model are taken from 2012. The output; total production and prices, should correspond to 2012 data when we model the countries with no cable. And even when introducing the cable, the total hydro production should be similar to that of 2012. The variables that are adjusted in order to calibrate the model are the minimum and maximum accepted prices for hydropower and the random variables. Also in the different scenarios, the model is calibrated such that the hydro production corresponds to the respective volume in each scenario. A list of all input variables is provided in Appendix 2.

Calculation of welfare effects

As we assume a completely inelastic demand, the change in consumer surplus for country *i* hour *t* when moving from state 1 (no cable) to state 2 (cable) is calculated as

$$CS_{ti} = \left(p_{ti_1} - p_{ti_2}\right) * D_{ti}$$

Change in producer surplus is calculated as

$$PS_{ti} = \left(p_{ti_2} * (D_{ti} + \mathrm{T_{new}}(\mathrm{p_{ti}}, \mathrm{p_{tf}})_{\mathrm{ti}}) - cost_{ti_2}\right) - \left(p_{ti_1} * D_{ti} - cost_{ti_1}\right)$$

The cost includes the cost of fossil production, the price for electricity imported through the old channels and as a negative cost, the price for electricity exported through the old channels. Since we allowed an imbalance of 100 MWh per hour in order to get our simulation model to work, and since the aggregated imbalance for a year can be different before and after trade is introduced, this imbalance could bias the changes in producer surplus. In the formula above, the revenues for producers are based on electricity that is sold while costs are based on electricity produced including the imbalance. We therefore added the difference in imbalance before and after trade multiplied by the price after trade to the change in producer surplus.

The congestion rent is also added to the change in producer surplus and is calculated as

$$C_t = \max\left(0; \left|p_{tj_2} - p_{ti_2}\right| * \mathrm{T_{new}}(\mathrm{p_{ti}}, \mathrm{p_{tf}})_{\mathrm{ti}}\right) + \max\left(0; \left|p_{ti_2} - p_{tj_2}\right| * \mathrm{T_{new}}(\mathrm{p_{ti}}, \mathrm{p_{tf}})_{\mathrm{ti}}\right)$$

Finally, we calculated the environmental effects. When doing this, we assumed all electricity imported or exported to the Netherlands, Germany and France to be conventional power. This is reasonable since even if the Nordics, as an example, export wind power to Germany, the effect will be that less conventional power is used in Germany resulting in environmental gains. We measured the environmental effects in tons of carbon dioxide emissions from the use of conventional power and gas turbines. When we calculated the emissions we have disregarded correcting for imbalances, which means that our figures are not exact. The reason to why we did this is that we did not know how much of the imbalance that was made up of coal.

Data

Data on installed capacities and total production 2012 is collected from the respective country's official statistics department. Data on prices and transmission capacities is from Nord Pool and APX. There are two spot markets in the UK but since APX was the first and APX prices are used as reference in Quarterly Report on European Electricity Markets (2012) we decided to use their prices as references. A comprehensive list of data can be found in the reference list. The APX prices are converted to euro using the yearly average exchange rate 2012 (Oanda, 2014).

Is 2012 a representative year?

In the Nordics, 2012 was on average slightly warmer than normal. However, one winter month was very cold resulting in a total yearly consumption two per cent larger than the preceding year. When discussing production, hydropower is the important factor to look at. 2012 was a slightly better year than normal with very high water reservoir levels in the beginning of the year (NordREG, 2013). When comparing hydro production in Norway between 2006 and 2012, we found that 2012 was around 7% better than average.

In the UK, there is a trend towards more wind power and less fossil fuels. Compared to earlier years, there is also substantially more electricity generated by wind in the UK. That is however due to additional capacity rather than abnormal wind conditions. When it comes to nuclear and hydropower, 2012 is very similar to earlier years and the same is true for consumption (Department of Energy & Climate Change, 2013).

8. Results and analysis

Do our simulations correspond to the actual data?

When we compare the prices our model calculates for our base case with the actual prices of 2012, we find that our prices for the UK are higher than in reality. We believe this is the case as gas producers do not purchase at wholesale prices, instead they probably buy gas separately at lower prices by having long-term contracts with producers. For the Nordic countries, average prices corresponded very well, but in reality prices vary more with demand. This is the case as we have assumed a constant maximum and minimum throughout the year. In reality there are some seasonal variations. In addition we believe our hydro producers behave more optimally than in reality as they can adjust their production hour by hour. Also, the real costs of using fossil power are higher as there are start-and-stop costs that we do not consider.

Welfare effects from trade in the Nordics and the United Kingdom with the generation mix of today

Table 3. Results - base and dry case

			Base case		Dry case	
			No cable	**1400GW cable**	**No cable**	**1400GW cable**
Nordics	Average Price	€/MWh	29.06	31.53	37.29	38.48
	Total production	GWh	386 828	399 013	387 332	393 908
	of which conventional steam power	GWh	2 577	14 787	37 832	42 926
	of which power from gas turbines	GWh	2.17	5.09	175	154
	Export to UK	GWh		12 248		7 656
	Change in consumer surplus	M €		- 1 001		- 470
	Change in producer surplus	M €		1 124		502
	of which congestion rent	M €		115		33
	Total welfare effect	M €		124		32
UK	Average Price	€/MWh	41.91	40.88	41.89	41.20
	Total production	GWh	309 526	297 781	309 557	302 568
	of which conventional steam power	GWh	223 457	214 711	223 558	218 688
	of which power from gas turbines	GWh	6 117	4 539	6 060	4 885
	Export to Nordics	GWh		1.88		462
	Change in Consumer surplus	M €		359		240
	Change in producer surplus	M €		- 351		- 232
	of which congestion rent	M €		0.03		2.38
	Total welfare effect	M €		8.16		7.89
Total	Total welfare gain	M €		**132**		**40**

The results in our first two cases are in line with our hypotheses. In the base case, there is an overall yearly welfare gain from trade of €132 M. The producers in the Nordics are the main winners; they enjoy higher prices and increase their production in order to export to the UK. The Nordic consumers on the other hand lose. Prices converge as a result of the interconnector but the price level in the UK is to a lesser extent affected. As a consequence, the UK has a lower total gain and less welfare redistribution between producers and consumers. The redistribution in the UK is, as predicted by theory, in the opposite direction compared to the Nordics.

The average price in the UK is 40% higher than the Nordics before the countries are connected. Still, there are two hours when trade takes the opposite direction. These hours occur in the winter when consumption in the Nordics is at peak level. In the Nordics, before introducing the interconnector there are 15 hours where there are excess supply and negative prices. These hours are in the summer when consumption is low and where there is high wind power production. With an interconnector to the UK, some of the excess supply can be exported and there are only five hours with negative prices left.

In the dry case, the decreased hydro production makes the Nordics more similar to the UK regarding production technologies. As a consequence, the pre-cable price difference between the countries is smaller than in the base case. The effect of trade is therefore lower, especially in the Nordics. The redistribution effect is about half as large and the welfare gain only around a quarter as much as in the base case. The number of hours where the UK exports to the Nordics has increased considerably compared to the base case and is now around 10% of total hours.

Before the cable is built, there is one hour in the Nordics where supply does not meet demand even though all production capacities run at maximum. The price this hour increases towards infinity. With an even lower hydro production, shortages like this would be more common. More trade decreases the risk of shortages. A shortage of electricity has serious consequences for society. Hence, taking the increased security of supply into account when calculating the benefits from trade will, at least partly, offset the lower welfare gains in a dry compared to a wet year.

Welfare effects from trade in Norway and the United Kingdom with the generation mix of today

Table 4. Results – UK-Norway base and UK-Norway dry case

			UK-Norway Base case		UK Norway Dry case	
			No cable	**1400GW cable**	**No cable**	**1400GW cable**
Norway	Average Price	€/MWh	29.72	32.00	56.73	54.53
	Total production	GWh	128 856	140 370	128 364	118 925
	of which conventional steam power	GWh	1 623	2 899	8 372	8 307
	of which power from gas turbines	GWh	-	-	-	-
	Export to UK	GWh		12 014		1 151
	Change in consumer surplus	M €		- 314		291
	Change in producer surplus	M €		432		- 225
	of which congestion rent	M €		109		12
	Total welfare effect	M €		118		65
UK	Average Price	€/MWh	41.91	40.90	41.90	42.89
	Total production	GWh	309 599	298 015	309 493	318 888
	of which conventional steam power	GWh	223 550	214 978	223 561	229 570
	of which power from gas turbines	GWh	6 143	4 573	6 083	7 932
	Export to Nordics	GWh		0.27		10 560
	Change in Consumer surplus	M €		352		- 351
	Change in producer surplus	M €		- 344		513
	of which congestion rent	M €		0.00		155
	Total welfare effect	M €		8.33		161
Total	Total welfare gain	M €		**127**		**227**

When investigating the effects of a cable between Norway and the UK, we also find results in line with our expectations. In the scenario based on Norwegian hydro production 2010, the direction of our results corresponds to Doorman & Frøystad (2013). Norway is the net importer and has decreasing prices as a result of trade. In the UK, prices are less affected and only a small increase occurs. Due to the limited size of the cable, the price difference is still large after the cable is introduced which benefits the producers in the UK that earn high congestion rents.

When comparing the generation mix of Norway with that of the whole Nordics, one might expect more shortages in the dry scenario as hydro production constitutes around 97% of the total production. But, since Norway is well integrated to the rest of the Nordics and also connected to the Netherlands (the maximum transmission capacity from Norway to other countries is one third of average consumption), the shortages can be offset by import. When comparing the dry Norway scenario with the dry Nordic scenario, we also see a large price difference. Prices in the dry Nordic case are far from being as high as in the Norway case and the Nordics do not become a net importer. The explanation for this is that the dry Nordics case is, except for hydro production, based on 2012 data. The same is true for dry Norway with one important exception. The prices for the rest of Nordics, which are very important for the Norwegian price formation, are exogenous and estimated from the actual yearly averages of 2010. These prices are significantly higher than those we get when simulating dry Nordics. This is a result of 2010 being different from 2012 in more ways than hydro production. Most important, the yearly average temperature was considerably lower (Klimatindikator – temperatur, n.d.). Lower temperatures yield a higher demand and hence higher prices.

In the scenario based on Norway and the UK in 2012, the effect is the opposite, clearly showing how important the generation mix (and in this case, particularly how certain production technologies are affected by weather conditions) is for determining both the size and allocation of welfare gains from trade. First, we see that because Norway now has lower prices than the UK before trade, Norway becomes the net exporter implying an opposite redistribution pattern between producers and consumers compared to the previous case. Second, we see that as the initial price differences are considerably smaller, the overall benefit is lower.

Welfare effects from trade in the Nordics and the United Kingdom with more wind power

Table 5. Results – More wind, less nuclear and specialization

			More wind. less nuclear		Specialisation	
			No cable	**1400GW cable**	**No cable**	**1400GW cable**
Nordics	Average Price	€/MWh	31.29	32.61	33.13	33.92
	Total production	GWh	387 325	394 043	387 420	391 762
	of which conventional steam power	GWh	17 089	23 321	20 658	24 490
	of which power from gas turbines	GWh	-	-	71	43
	Export to UK	GWh		7 466		5 380
	Change in consumer surplus	M €		- 559		- 315
	Change in producer surplus	M €		568		336
	of which congestion rent	M €		45		31
	Total welfare effect	M €		9.27		21
UK	Average Price	€/MWh	36.15	35.60	36.89	36.35
	Total production	GWh	310 352	303 806	309 871	302 853
	of which conventional steam power	GWh	159 595	153 748	228 699	226 630
	of which power from gas turbines	GWh	1 114	725	7 437	5 558
	Export to Nordics	GWh		986		952
	Change in Consumer surplus	M €		179		193
	Change in producer surplus	M €		- 176		- 187
	of which congestion rent	M €		11		3.04
	Total welfare effect	M €		2.92		6.65
Total	Total welfare gain	M €		**12**		**27**

Moving on to the scenarios where wind production is set so that the countries fulfil their 2020-goals, we discovered a drawback with our model. In hours where the constantly running technologies produce more than what is demanded, the price goes towards minus infinity. This is also the case in the actual electricity market and we see negative prices for several hours in our data of foreign prices. However, the final prices for these hours are in our simulation determined by how many times the iteration loop runs. When the number of hours with excess supply gets large, as it does for the Nordic countries, it therefore makes no sense to compare the estimated prices before and after the cable is introduced. However, we can conclude that increasing wind generation in line with the 2020 goals without decommissioning any nuclear, hydro or CHP generation is not sustainable. The yearly average price is negative and there is excess supply in more than half of the hours. This problem is partly reduced but far from solved with a 1400 MW cable to the UK.

Interestingly, when increasing the maximum capacity and enabling free trade, the problem of excess supply fully disappears from both countries and we get a yearly average price of around 30

€/MWh. Trade moves in both directions enabling both countries to offset the variations of wind. However, the cable size needed to enable free trade is over 20 000 MW.

When nuclear power in Sweden is decommissioned, the Nordic market does not have more excess supply hours than in the base case. However, electricity generated from fossil power is eight times higher than in the base case. In this scenario, the Nordic generation mix is more similar to that of the UK and the effect from trade is small. As in previous scenarios, the effect is larger in the Nordic market which is the net exporter. In around 18% of hours, trade takes the opposite direction.

Looking at the scenario where we let the countries specialize in wind and flexible power respective, one interesting thing to note is that the Nordic pre-cable scenario uses a considerable amount of electricity from gas turbines. As the only thing that distinguishes the Nordics in this scenario compared to the previous described scenario is the randomization of wind and nuclear, we can now see how big an impact the randomness of wind and technological ability has on price. In this scenario, we also see that even though the UK has cheaper conventional production, the Nordics increase their conventional production as a result of trade. This is because the Nordics still have a lower price thanks to the hydropower that is used in such way that only the cheapest conventional sources need to be used for most hours. The use of gas turbines decreases in both countries but in relative terms more in the Nordics that has higher marginal costs for gas. The total welfare gain is higher compared to the previous scenario.

What is the environmental effect of trade?

Billette de Villemeur & Pineau (2012) stress in their study the importance of taking the environmental effects into account when calculating welfare effects. As is commonly known, electricity generation from fossil fuels is associated with large negative externalities in terms of carbon dioxide emissions. It is therefore of large importance to include changes in the use of fossil fuels when calculating the welfare effects of trade. However, trade generally is a zero-sum game when it comes to carbon dioxide emissions. As Denny et al. (2010) find, trade shifts some emissions from the high price country to the lower one, but as long as the generation mix is unchanged, the amount of emissions cannot be reduced. The exception is when there is overproduction. Then the excess supply can be exported and replace fossil power production in the importing country.

In the scenario with more wind, there is a large reduction in emissions in the UK, which illustrates how overproduction in one region before trade can lead to reduced use of fossil power when trade is enabled. Before trade, the UK will have to use fossil power to complement the fluctuating wind power. When there is an interconnector to the Nordic countries, any overproduction there can to some extent replace fossil power as a complement to the UK's wind power. This is in line with what Schaber et al. (2012) find, namely that a larger interconnected geographical area increases the chances of there being sufficient wind somewhere, thereby enabling areas with overproduction to transfer electricity to deficit areas.

Table 6. Results – Emissions

Scenario	Country	Change in CO2 emissions (K ton)
Base case	Nordics	4302
	UK	-3901
	Total	401
Dry case	Nordics	2332
	UK	-2283
	Total	49
Norway-UK Dry case	Norway	-3357
	UK	3026
	Total	-332
Norway-UK Base case	Norway	3963
	UK	-3840
	Total	123
More wind	Nordics	66
	UK	-4177
	Total	-4111
More wind, less nuclear	Nordics	2591
	UK	-2252
	Total	339
Special-isation	Nordics	1596
	UK	-1216
	Total	380

What happens when we enable free trade?

As stated in the theory section, the full benefits of trade cannot be reaped when trade is limited. We therefore tested to increase the cable size in order to test what happens with free trade. When increasing the size of the interconnector, the prices converge. We do not however manage to get a single market price due to inexactness of the model. The yearly average price differs with around € 0.5 and the hourly price differs with up to € 1. However, using an interconnector is associated with some quantity losses why prices in reality will neither converge fully.

The transmission capacity needed in order to enable free trade varies between the different scenarios. It seems like higher shares of wind power increases the capacity needed, probably

because the high variety in wind production. Even with the wind capacity of today, we see that the cable size needed to get the full benefits from trade a normal year is ten times larger than the planned interconnector. We therefore do not see total integration with the UK as a future option.

Table 7. Cable size

Scenario	Cable size (MW)
Base case	13 422
Dry case	9 570
Dry case Norway UK	10 116
Base case Norway UK	10 080
More wind case	20 804
More wind, less nuclear	14 570
Specialisation in both countries	12 520

9. Discussion

In our scenarios we have disregarded any costs of constructing the electricity interconnector. We have also assumed that the producers are the ones who own the interconnector and hence make any profits. As there in reality are significant costs involved in the planning and building of an interconnector (Doorman & Frøystad, 2013), the producers will only invest in the cable if they are certain that it is profitable in the long run.

Our scenarios suggest that there will be benefits of trade as long as there are price differences between the two regions before trade, which is in line with theory. If for some reason in the future, prices in the Nordic countries and the United Kingdom would be similar even in the absence of trade, having an interconnector would no longer be profitable. This could happen as a result of changes in the generation mix. The decommissioning of nuclear power in the Nordic countries or if climate changes would negatively affect hydropower output, would for instance increase prices in the Nordic countries. A change in the generation mix that is about to occur is that both regions are increasing their dependence on wind power and other intermittent energy sources. As a result, this change can lead to prices converging. In this case, trade would however fill an important function as a way of reducing fluctuating supply. This is in line with our results as well as those of Schaber et al. (2012). Hence, as long as countries continue to invest in intermittent electricity sources, there should be incentives to build the cable.

In accordance with our hypothesis, our results show that electricity trade affects electricity prices. Prices in the exporting region increase while they decrease in the importing region. As a consequence, there is a redistribution of welfare both within and between regions. In the net

importing country, consumers gain and producers lose from trade while the opposite is true for net exporting countries. We have also shown that trade results in an overall gain.

Since the exact shape of the supply curve shifts from hour to hour, the effects of trade can be very different. On an aggregated yearly level though, our results suggest that the Nordic countries are net exporters of electricity to the United Kingdom. However, as illustrated in the dry scenarios, the available hydropower capacity has a large impact on prices and trade patterns.

What we also discovered when comparing our calculated prices from the models using hydro production from 2010 with the actual prices of that year was how much shifts in demand affect price. An improvement of our model would have been to have demand as a function of hourly temperature and compare scenarios with cooler and warmer weather. In the event of drought in combination with a cold winter, the Nordic countries may become net importers.

Additionally, as the results of our different scenarios show that differences in generation technology and generation mixes impact trade patterns, any future changes in these will affect the magnitude and direction of redistribution. We see that increased wind leads to excess supply and negative prices that hurt producers. This problem can partly be remediated by trade. If wind power increases according to the 2020 renewable targets, for trade to have an effect, the cable's capacity needs to be substantial. When balancing increased wind with decreased nuclear in the Nordics, the countries are more similar to each other and the impact of trade is less. This is the same pattern as we see in the dry scenario, which demonstrates the fact that the gains from trade diminish the more similar the countries are before trade. However, even when considering countries that are alike, there are positive impacts of trade such as increased security of supply and less price fluctuations. The gains from these aspects are however difficult to quantify.

Another important factor is the capacity of the interconnector. As previously discussed, prices converge to a greater extent with more interconnection capacity. The larger the maximum difference in price is before trade, the larger transmission capacity is needed in order to create full price convergence. In this thesis, we consider the effects of an interconnector with a 1400 GW capacity. With additional interconnector capacity, the impact on prices and welfare will be in the same direction but be greater. This is suggested by prices going towards equalization when unlimited trade is allowed.

Wider implications of electricity trade

Considering that 2012 was more or less an average year when it comes to temperature and hydro production we can assume that the redistribution of welfare generally is as our base scenario suggests. This is as long as there are no major changes to the two regions' electricity production structure. The winners in the United Kingdom are hence the consumers who get lower prices. In the case of the UK's electricity intensive industries, the gain might be twofold. On one hand lower prices will increase their competitiveness, on the other, if prices decrease enough, the government might reduce or cease its support. However, as the producers in the United Kingdom lose and, some power plants might have to shut down, they might demand some sort of compensation.

In the Nordic countries, the increase in prices leads to consumers losing while producers gain. The fact that consumers lose could have a large impact on the economy. As mentioned, due to electricity prices historically being low, electricity intensive industries are an important part of the Nordic countries' economies. An increase in electricity prices would negatively affect these industries' competitiveness.

There are already support schemes where energy intensive industries are given large amounts of the emissions allowances for free. If electricity prices were to increase, the government might have to increase their support. Furthermore, as there is a large share of the Nordic population who use electricity for heating, higher electricity prices will immediately negatively impact them. In order to manage the increased costs, one could imagine they might demand some government support. As there are winners and losers of integration, the question about redistribution and compensation is interesting. How possible compensation schemes are designed and how they should be funded could be a topic for further research.

It is also important to consider that there are potential wider overall gains (or losses) as well as long-term ones from increased integration that are beyond those considered in our partial equilibrium model. A few have already been mentioned such as increased security of supply and reduced price fluctuations. Others, such as benefits highlighted by the EU, are increased competition in generation and distribution, more choices for consumers, better investment choices and more cooperation between countries. To take an example, due to higher prices there might be an increase of producers in the Nordic countries seeking to claim a share of the increased profits.

The point is, though giving an important indication of how welfare is affected by changes in electricity prices, a partial equilibrium model will not provide the whole picture of how all parts of

society and the economy are affected. As some production moves from one country to another, production factors such as labour and capital need to be reallocated which could be both beneficial and harmful. In addition, not only the absolute price of electricity needs to be considered but also the price in relation to other goods. Although there are no existent substitutes to electricity, consumers might be reluctant to spend more of their income on electricity and seek to switch to more energy efficient technologies. In order to better understand the wider consequences of increased electricity integration, future research could use a general equilibrium model.

In our scenarios with increased wind power we see several interesting implications. If prices were to increase in the Nordics it might be more profitable to invest in renewable energy sources such as wind and solar power, which might in turn reduce the need of government support schemes. However, as our more wind scenario suggests, increases in wind power without any decommission of existing generation leads to overproduction, which in turn leads to electricity prices going towards zero. The more wind power there is, the lower the prices, and the less incentive there is to invest in wind power.

In our more wind scenario, with sufficient trading capabilities, the excess production could be exported and prices would increase. However, in order to have any meaningful effect on prices, the capacity of the interconnector will have to be substantial. Also, if there are large investments in renewables everywhere, without significant decommission the problem with overproduction remains. Furthermore, the decommission of certain technologies that have close to zero marginal cost, such as CHP, nuclear and hydropower, would be a waste of resources. At the same time, flexible generation technologies such as coal and gas fired generation are needed to manage issues with the fluctuating supply of wind power and other intermittent sources. The positive environmental effect associated with increases in wind power might therefore be offset to some extent if coal and gas generation replaces other sources that are more environmentally friendly. This effect is suggested in our scenario with more wind and less nuclear in the Nordic countries. In the light of the above discussion, the earlier mentioned findings of Schaber et al. (2012) should be noted. The overproduction issue can be mitigated to some extent if a larger geographical area is interconnected. Within a large area, there could be favourable weather conditions for wind power in one part, while in another there are not. Therefore, overproduction of wind power can be exported to where it is needed. Considering the results of our more wind scenario regarding emissions, they suggest that this occurs and as a result wind power can complement wind power. Thereby the need for backup fossil generation is reduced. This result is in line with another finding

of Schaber et al. (2012), namely that though still of importance, the amount of backup generation required is lessened when there is geographical spreading of wind power.

It is also important to consider the environmental impact of different generation technologies. The full costs of emissions and environmental damage are difficult to quantify as well as the value of a better environment. Therefore it is difficult to judge correctly the electricity costs of different production sources. For instance, according to Billette de Villemeur & Pineau (2012), electricity markets are efficient when prices are set at marginal cost as long as the environment is not considered. When the environmental impact is accounted for prices are too low. If electricity produced by fossil fuels were to be considerably more expensive, investments and development of renewable energy sources might not need to be subsidised.

This discussion regarding the impact of increased dependence on wind power is solely based on the outcomes of our scenarios as well as findings in previous research and further investigation is outside the scope of this thesis. For more information regarding issues associated with intermittent renewable sources such as wind power, see for example Jauréguy-Naudin (2010) and Eurelectric (2010).

10. Conclusions

Our aim with this thesis was to investigate the welfare effects of integrating the high-cost electricity market of the United Kingdom with the low-cost one of the Nordic countries. In order to accomplish this we sought to answer three questions:

How are electricity prices affected by electricity trade between these two markets?

How does electricity trade affect the welfare of consumers and producers in each region?

How are trade patterns affected by differences in the characteristics of generation technology as well as differences in the production mix?

Regarding the first question, our results show that trade always goes from the area where prices are lower to where they are higher. In a normal year, this implies a net effect of electricity being exported from the Nordic countries to the United Kingdom. The effect on prices is that they converge.

To answer the second question, as electricity prices increase in the Nordic countries, the effect on welfare is that their consumers lose while producers gain. In the United Kingdom the opposite occurs, consumers gain while producers lose.

Lastly, concerning the third question, differences in the generation mix between the two regions does have an impact on trade patterns. The reason why prices in the Nordic countries are in average lower than in the UK, is that a larger share of their production is made up of inexpensive hydropower. When there are changes to the production mix, as illustrated in our scenarios with increased wind or decreased nuclear capacity, prices in each region can vary considerably, which in turn affects the direction of trade flows. The variability of output characterising certain electricity generation technologies does also have an impact on trade patterns. As wind power can fluctuate greatly due to weather conditions and available hydropower can vary depending on water levels, uncontrollable factors affect supply, which in turn has an effect on prices.

The consequences are, even though at present electricity in the United Kingdom is generally more expensive, at times prices in the Nordic countries are higher. Hence, the direction of trade can change from one hour to another depending on which region has the highest or lowest price in that particular hour. If there are changes to the two regions generation mixes, for example by increasing the dependence on intermittent technologies such as wind power, fluctuations in trade patterns increase. Therefore it is important, when analysing the welfare effects of trade, to also consider long-term effects. Depending on which electricity sources will be used in the future and how these sources are affected by uncontrollable factors, the effect of trade will differ. If these sources are to a large degree affected by weather conditions, in order to further evaluate welfare effect associated with the integration of electricity markets, all possible weather scenarios should be considered.

References

ACER. (2011). *Framework guidelines on capacity allocation and congestion management for electricity* (FG-2011-E-002). Ljubljana: Agency for the Cooperation of Energy Regulators, 29 July.

ACER & CEER. (2013). *Annual report on the results of monitoring the internal electricity and natural gas markets in 2012*. Luxembourg: Publications Office of the European Union.

Amundsen, E. S., Bergman, L. & Fehr, N.-H. M., (2006). The Nordic electricity market: Robust by design? In Sioshansi, F. P., & Pfaffenberger, W. (2006). *Electricity market reform: An international perspective* (pp. 145-170). Amsterdam: Elsevier.

Auction. (n.d.). Retrieved May 7, 2014 from http://www.apxgroup.com/trading-clearing/auction/

Bergman, L. (2002). The Nordic electricity market-continued success or emerging problems?. *Swedish economic policy review*, *9*(2), 51-88.

Bidding areas. (n.d.). Retrieved 29 April, 2014 from http://www.nordpoolspot.com/How-does-it-work/Bidding-areas/

Billette de Villemeur, E., & Pineau, P. O. (2012). Regulation and electricity market integration: When trade introduces inefficiencies. *Energy Economics*, *34*(2), 529-535.

Blesl, M., Wissel, S., & Mayer-Spohn, O. (2008). *Private costs of electricity and heat generation*. Report for CASES – Cost Assessment for Sustainable Energy Systems (Project No 518294 SES6). Stuttgart: IER University Stuttgart.

Borggrefe, F., & Neuhoff, K. (2011). *Balancing and intraday market design: Options for wind integration* (Discussion paper No. 1162). Berlin: German Institute for Economic Research, DIW Berlin, October.

Brännlund, R., Karimu, A., & Söderholm, P. (2012). *Elmarknaden och elprisets utveckling före och efter avregleringen: Ekonometriska analyser* (Working paper No. 2012: 14). Umeå: The Center for Environmental and Resource Economics, Umeå universitet, 31 May.

Consulting early on Swedish new nuclear build. (2014, 16 January). Retrieved May 9, 2014, from http://www.world-nuclear-news.org/NN-Consulting-on-Swedish-new-build-1601141.html

Denny, E., Tuohy, A., Meibom, P., Keane, A., Flynn, D., Mullane, A., & O'Malley, M. (2010). The impact of increased interconnection on electricity systems with large penetrations of wind generation: A case study of Ireland and Great Britain. *Energy Policy*, *38*(11), 6946-6954.

Department of Energy & Climate Change. (2010). *National renewable energy action plan for the United Kingdom, article 4 of the renewable energy directive 2009/28/EC.* London: Author.

Department of Energy & Climate Change. (2013). Electricity. In Department of Energy & Climate Change. (2013). *Digest of United Kingdom energy statistics 2013* (pp. 111-154). London: The Stationary Office Limited.

Department of Energy & Climate Change. (2014, March). Section 5 – Electricity. Retrieved 10 May 2014, from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/295355/5_Electricity.pdf

Doorman, G. L., & Frøystad, D. M. (2013). The economic impacts of a submarine HVDC interconnection between Norway and Great Britain. *Energy Policy*, *60*, 334-344.

Efficient Dispatch Toolkit Steering Committee. (2011). *White paper energy imbalance market functional specification.* Salt Lake City: Western Electricity Coordinating Council, September 8

Energy intensive industries. (2012, 4 December). Retrieved 10 May, 2014 from http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenvaud/writev/669/eii02.htm

ENTSO-E. (2014). *Technical report, bidding zones review process.* Brussels: European Network of Transmission System Operators for Electricity, 2 January.

ERGEG. (2010). *Draft framework guidelines on capacity allocation and congestion management for electricity - initial impact assessment* (Ref:E10-ENM 20-04). Brussels: European Regulators' Group for Electricity and Gas, 8 September.

Eurelectric. (2010). *Integrating intermittent renewables sources into the EU electricity system by 2020: Challenges and solutions* (D/2010/12.205/15). Brussels: Author.

European Commission. (2007). *DG competition report on energy sector inquiry* (SEC(2006) 1724). Brussels: Author, 10 January.

European Commission. (2010). *Options paper for day-ahead electricity market governance guideline* (D(2010)). Brussels: Directorate-General for Energy, 6 December.

European Commission. (2011). *Public consultation on the governance framework for the European day-ahead market coupling* (D(2011) 1176339). Brussels: Directorate-General for Energy, 28 November.

European Commission. (2012). *Making the internal energy market work* (COM(2012) 663 final). Brussels: Author, 15 November.

European Commission. (2013). *Long term infrastructure vision for Europe and beyond* (COM(2013) 711 final). Brussels: Author, 14 October.

European integration – overview. (n.d.). Retrieved 7 May, 2014 from http://www.nordpoolspot.com/How-does-it-work/European-Integration/

EuroPEX. (2004). *EuroPEX's comments on the draft congestion management guidelines*. Brussels: Association of European Power Exchanges, June.

EWEA. (2011). *EU energy policy to 2050 - achieving 80-95% emissions reductions*. Brussels: The European Wind Energy Association, March.

EWEA. (2013). *European offshore wind industry - key trends and statistics 2012*. Brussels: The European Wind Energy Association, January.

Explicit and implicit capacity auction. (n.d.). Retrieved 4 May, 2014 from http://www.nordpoolspot.com/Global/Download Center/how-does-it-work_explicit-and-implicit-capacity-auction.pdf

Finon, D., & Romano, E. (2009). Electricity market integration: Redistribution effect versus

resource reallocation. *Energy Policy*, *37*(8), 2977-2985.

Førsund, F. R. (2009). *Energy in a bathtub: Electricity trade between countries with different generation technologies* (Memorandum No. 2009.17). Oslo: Department of Economics, University of Oslo.

Gimeno-Gutiérrez, M., & Lacal-Arántegui, R. (2013). *Assessment of the European potential for pumped hydropower energy storage.* Luxembourg: Publications Office of the European Union

Heddenhausen, M. (2007). *Privatisations in Europe's liberalized electricity markets–the cases of the United Kingdom, Sweden, Germany and France.* Berlin: Research Unit EU Integration, German Institute for International and Security Affairs.

Holmberg, P., & Lazarczyk, E. (2012). *Congestion management in electricity networks: Nodal, zonal and discriminatory pricing* (IFN Working Paper No. 915). Stockholm: Research Institute of Industrial Economics, 27 March.

House of Commons Energy and Climate Change Committee. (2011). *Electricity market reform – fourth report of session 2010-2012. Volume 1*. London: The Stationary Office Limited.

International Energy Agency. (2010). *Projected costs of generating electricity: 2010 edition*. Paris: OECD.

Intraday market. (n.d.). Retrieved May 9, 2014 from http://www.nordpoolspot.com/How-does-it-work/Intraday-market-Elbas/

Jaakko Karas, P. S. (2013). *The increasing scope and authority for power exchanges* (Elforsk rapport 13:57). Stockholm: Elforsk, June

Jauréguy-Naudin, M. (2010). *Wind power, a victim of policy and politics.* Paris: Institut Français des Relations Internationales, October.

Karan, M. B., & Kazdag˘li, H. (2011). The development of energy markets in Europe. In Dorsman, A., Westerman, W., Karan, M. B., & Arslan, O. (2011). *Financial aspects in energy: A European perspective* (pp. 11-32). Berlin, Heidelberg: Springer-Verlag Berlin Heidelberg.

Klima- og Energiministeriet. (2010). *National action plan for renewable energy in Denmark.* Copenhagen: Author, June.

Klimatindikator – temperature. (n.d). Retrieved 14 May, 2014 from http://www.smhi.se/klimatdata/meteorologi/temperatur/klimatindikator-temperatur-1.2430?print=yes

Krugman, P. R., Obstfeld, M., & Melitz, M. J. (2012). *International economics: Theory & policy*. Boston: Pearson Addison-Wesley.

Kunz, F. (2012). *Managing congestion and intermittent renewable generation in liberalized electricity markets* (Doctoral dissertation). Dresden: Technischen Universität Dresden, 28 June.

List of projects submitted to be considered as potential projects of common interest in energy infrastructure – Electricity. (2012, 27 July). Retrieved 4 May, 2014, from http://ec.europa.eu/energy/infrastructure/consultations/doc/pci_list_electricity.pdf

Madlener, R., Bernstein, R., & Gonzalez, A. (2011). Econometric estimation of energy demand elasticities. *E. ON Energy Research Center Series*, *3*(8).

Malaguzzi Valeri, L. (2009). Welfare and competition effects of electricity interconnection between Ireland and Great Britain. *Energy Policy*, *37*(11), 4679-4688.

Ministry of Employment and the Economy. (2010). *Finland's national action plan for promoting energy from renewable sources pursuant to directive 2009/28/EC.* Helsinki: Author.

Ministry of Petroleum and Energy. (2012). *National renewable energy action plan under directive 2009/28/EC, Norway.* Oslo: Author, September.

Newbery, D., Strbac, G., Pudjianto, D. & Noël, P. (2013). *Benefits of an integrated European energy market. Revised final report.* Prepared for the European Commission Directorate - General Energy. Amsterdam: Booz & Company, 20 July.

Noothout, P., Koornneef, J., de Jager, D., & Klaassen, E. (2013). *International comparison of fossil power efficiency and CO_2 intensity – update 2013.* Utrecht: Ecofys, August.

Nordic Council of Ministers. (2008). *The Nordic energy markets and environment* (TemaNord 2007:613). Copenhagen: Author, 26 February.

Nordic Energy Research & International Energy Agency. (2013). *Nordic energy technology perspectives - pathways to a carbon neutral energy future.* Paris: OECD/IEA

NordREG. (2006). *The integrated Nordic end-user, electricity market – feasibility and identified obstacles* (Report 2/2006). Eskilstuna: Nordic Energy Regulators, February.

NordREG. (2013). *Nordic market report 2013 - development in the Nordic electricity market* (Report 6/2013). Oslo: Nordic Energy Regulators, July.

Nuclear power in Finland. (2014, April). Retrieved May 9, 2014 from http://www.world-nuclear.org/info/Country-Profiles/Countries-A-F/Finland/

NWE day-ahead market coupling project 3rd progress report. (2013, March). Retrieved 9 May, 2014 from http://static.epexspot.com/document/22764/NWE - 3rd Progress report – March 2013

NWE day-ahead price coupling: Questions & answers. (n.d.). Retrieved 4 May, 2014 from http://www.casc.eu/media/NWE%20Docs/NWE_QA.pdf

OFGEM. (2010). *Demand side response, a discussion paper* (ref 82/10). London: The Office of Gas and Electricity Markets, 15 July.

OFGEM. (2012). *Open letter: Implementing the European electricity target model in Great Britain*. London: The Office of Gas and Electricity Markets, 28 March.

Oxera. (2013). *The EU electricity target model: The devil is in the details?* Oxford: Author, January.

Parisio, L., & Bosco, B. (2008). Electricity prices and cross-border trade: Volume and strategy effects. *Energy Economics*, *30*(4), 1760-1775.

PB Power & Royal Academy of Engineering. (2004). *The cost of generating electricity*. London: Royal Academy of Engineering.

Price calculation. (n.d.). Retrieved May 9, 2014, from http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-calculation/

Price formation in Nord pool spot. (n.d.). Retrieved 29 April, 2014 from http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-formation-in-Nord-Pool-Spot/

Producers. (n.d.). Retrieved 4 May, 2014 from http://www.nordpoolspot.com/How-does-it-work/The-market-members/Producers/

Regeringskansliet. (2010). *The Swedish national action plan for the promotion of the use of renewable energy in accordance with directive 2009/28/EC and the commission decision of 30.06.2009.* Stockholm: Author, 23 June.

Renewable energy. (n.d.). Retrieved 4 May, 2014 from http://ec.europa.eu/energy/renewables/index_en.htm

Schaber, K., Steinke, F., Mühlich, P., & Hamacher, T. (2012). Parametric study of variable renewable energy integration in Europe: Advantages and costs of transmission grid extensions. *Energy Policy*, *42*, 498-508.

Single market for gas & electricity. (n.d.). Retrieved 29 April, 2014 from http://ec.europa.eu/energy/gas_electricity/legislation/legislation_en.htm

Successful operation of PCR solution: Power exchanges focus on pan-European power market. (2014, 19 February). Retrieved 4 May, 2014 from https://www.epexspot.com/fr/presse/communique-de-presse/detail/press/Successful_operation_of_PCR_solution_Power_Exchanges_focus_on_Pan-European_power_market

The 2020 climate and energy package. (2014, April). Retrieved 4 May, 2014 from

http://ec.europa.eu/clima/policies/package/index_en.htm

The 2030 framework for climate and energy policies. (2014, April). Retrieved 6 May, 2014 from http://ec.europa.eu/clima/policies/2030/index_en.htm

The day-ahead market – Elspot. (n.d.). Retrieved May 9, 2014 from http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/

TradeWind. (2009). *Integrating wind - developing Europe's power market for the large-scale integration of wind power* (2nd edition). Brussels: The European Wind Energy Association, February.

Trading and services. (n.d.). Retrieved 14 May, 2014 from http://www.nordpoolspot.com/TAS/

Vgb Powertech. (2012). *Vgb survey 2012 investment and operation cost figures - generation portfolio.* Essen: Author, September.

Welcome to the NorthConnect web site. (n.d.). Retrieved 17 April, 2014 from http://www.northconnect.no

What is NorthConnect? (n.d.). Retrieved 17 April, 2014 from http://www.northconnect.no/files/31860-E01d_A4-version.pdf

European Union legal sources

Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020 [2009] OJ L140/136

Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity [1996] OJ L27/20

Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC [2003] OJ L176/37

Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC [2009] OJ L140/16

Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community [2009] OJ L140/63

Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC [2009] OJ L211/55

Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity [2003] OJ L176/1

Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 [2009] OJ L211/15

Data sources

The UK

Data on yearly production, installed capacity and transmission capacities

Department of Energy & Climate Change. (2013). Electricity, table: 5.2, 5.5, 5.6, 5.7, 5.10, 5.11. In *Digest of United Kingdom energy statistics.* Retrieved 14 May, 2014 from https://www.gov.uk/government/publications/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Data on reference prices, hourly consumption

APX spot market. (2014). *UKPX historical data, APX power UK RDP historical data, 2012, Table: Reference price data HH ONLY 2012.* Retrieved 14 May, 2014 from http://www.apxgroup.com/market-results/apx-power-uk/ukpx-rpd-historical-data

National Grid. (2012). *Data explorer, historical demand data, table: demand_Jan 2010 to Dec 2012.* Retrieved 14 May, 2014 from http://www2.nationalgrid.com/uk/Industry-information/Electricity-transmission-operational-data/Data-Explorer/

The Nordics

Data on yearly production and installed capacity

Energistyrelsen, (2012). *Annual energy statistics, table energy statistics 2012.* Retrieved 14 May, 2014 from http://www.ens.dk/node/2228

Official Statistics of Finland (OSF). (2014). *Energy supply and consumption, table: Electricity supply and production, production and total consumption of electricity, GWh, district heat production, GWh, industrial heat production, GWh*. Retrieved 14 May, 2014 from http://www.stat.fi/til/ehk/tau_en.html

Statistiska centralbyrån. (2013). *Årlig energistatistik (el, gas och fjärrvärme), table: Bränsleförbrukning för elproduktion i Sverige efter produktionsslag och bränsletyp. År 1990 – 2012, eltillförsel i Sverige efter produktionsslag. År 1986 – 2012.* Retrieved 14 May, 2014 from http://www.scb.se/sv_/Hitta-statistik/Statistik-efter-amne/Energi/Tillforsel-och-anvandning-av-energi/Arlig-energistatistik-el-gas-och-fjarrvarme/6314/6321/

Statistisk sentralbyrå. (2012). *Electricity, annual figures, 2012, table: Energy and manufacturing.* Retrieved 14 May, 2014 from https://www.ssb.no/en/energi-og-industri/statistikker/elektrisitetaar/aar/2014-03-28?fane=om#content

Swedish energy agency. (2012). *Energy in Sweden - facts and figures.* Retrieved 14 May, 2014 from https://www.energimyndigheten.se/Global/Engelska/Facts%20and%20figures/Energy%20in%20Sweden%20facts%20and%20figures%202012%20(2).pdf

Data on reference prices, hourly consumption and transmission capacities

Nord pool spot. (n.d.) *Data download page, table: Production per country_2012_Hourly, consumption per country_2012_Hourly, elspot prices_2012_Hourly_EUR, market coupling capacity_2012_hourly*. Retrieved 14 May, 2014 from http://nordpoolspot.com/Market-data1/Downloads/Historical-Data-Download1/Data-Download-Page/

Nord pool spot. 2011. *Download centre, statistical market report, 2010 Dec.* Retrieved 14 May, 2014 from http://nordpoolspot.com/Download-Centre/

Data on foreign prices

Data on German, French and Dutch prices is retrieved from Vattenfall AB and can be available on request from the authors.

Data on costs for conventional power

Department of Energy & Climate Change. (2014). *Prices of fuels purchased by major power producers, QEP 3.2.1.* Retrieved 14 May, 2014 from gov.uk https://www.gov.uk/government/publications/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Dong energy. (n.d.). *Business activities, thermal power, activities.* Retrieved 14 May, 2014 from http://www.dongenergy.com/EN/business%20activities/generation/Pages/index.aspx

EEX. (n.d.) *Market data, emission allowances, spot market, European emission allowances (EUA)* Retrieved 14 May, 2014 from https://www.eex.com/en/market-data/emission-allowances/spot-market/european-emission-allowances#!/2014/05/14

IEC- Israel Electric Corporation. (2013). *IEC GHG grid emission factor 2006 – 2013.* Retrieved 14 May, 2014 from http://www.iec.co.il/environment/Documents/Israeli_GHG_grid_2006_2013.pdf

Oanda. (2014). *Historical exchange rates. average rate euro to British pound 2012-01-01 to 2012-12-31.* Retrieved 14 May, 2014 from http://www.oanda.com/currency/historical-rates/

Appendix

Appendix 1, costs of fossil power production

Costs for producing fossil power vary depending on the type of power plant and the assumptions made regarding fuel and carbon dioxide price. When looking at different studies, we could not determine which values that best corresponded to 2012.

Table 1

Technology	Fuel	Efficiency	Cost/MWh	Cost €/MWh	Source	note
Condensing power plant	Coal	40%	28.8	£ 42.4	The Royal Academy of Engineering (2004). future scenario	using average exchange rate of 2004
	Bio fuel	24%	8.4	£ 12.4		
Open-cycle gas turbine	Gas	53%	25.5	£ 37.6		
Closed-cycle gas turbine	Gas	60%	18.2	£ 26.8		
Condensing power plant	Coal	45%	52	€ 52.0	VGB (2011) 2011 scenario	Data measured from graph. not exact
	Coal/Bio fuel	45%	48	€ 48.0		
Open-cycle gas turbine	Gas	45%	74	€ 74.0		
Closed-cycle gas turbine	Gas	60%	55	€ 55.0		
Condensing power plant	heavy oil	43%	57.12	€ 57.1	Blesel et.al. (2007) 2020 scenario. 5% discount ratet	No CO2 costs
	coal	50%	15.54	€ 15.5		
Open-cycle gas turbine	light oil	38%	94.8	€ 94.8		
	Gas	46%	60.15	€ 60.2		
Closed-cycle gas turbine	Gas	62%	37.84	€ 37.8		
Condensing power plant	Coal	46%	50.24	$ 37.9	IEA (2010). 2010 Germany scenario	using average exchange rate of 2010
Open-cycle gas turbine	Gas	38%	108.4	$ 81.8		
Closed-cycle gas turbine	Gas	60%	68.65	$ 51.8		

We therefore decided to estimate marginal costs ourselves based on the following assumptions derived from 2012 data:

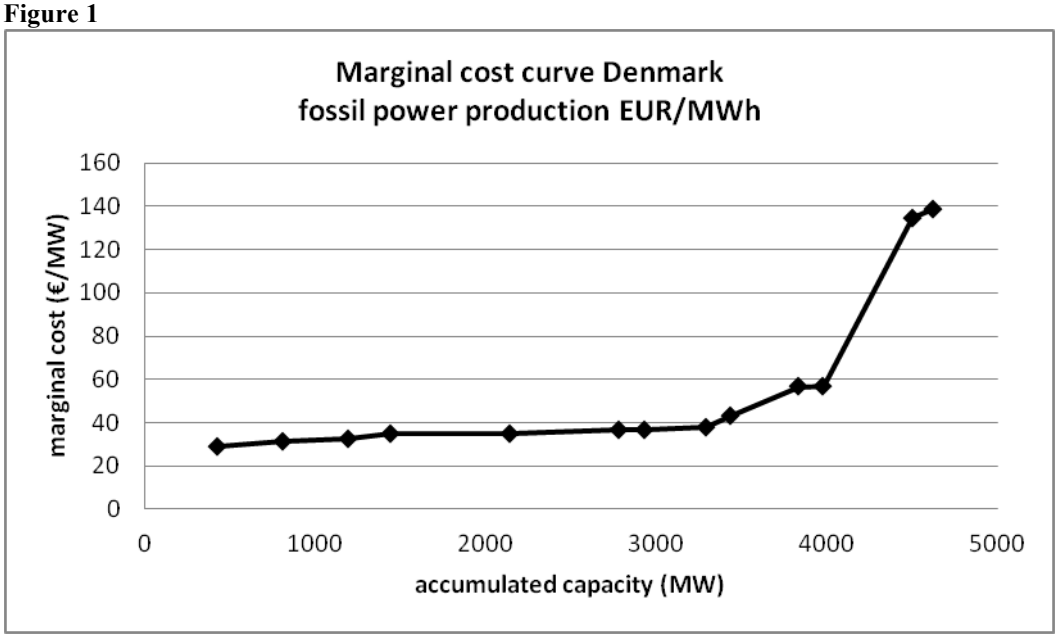
Table 2

Fuel	Price (€/ton)	Electricity generated (MWh/ton)	Co2 emisions ton/MWH
Coal	81.8	7.0	0.35
Natural Gas	26.3	13.8	0.20
Fuel Oil	541.3	11.3	0.28

The price for CO2 emissions was assumed to be 7 € per ton based on a 2012 average from EEX.

Furthermore, the only comprehensive data of fossil power plants we could find were of plants in Denmark. Therefore, we have assumed the other countries' fossil production capacity to be allocated in the same way as the Danish when it comes to fuel use and efficiency.

Figure 1



In our model, we group fossil powers into conventional and gas power. Conventional power is the flatter part of the curve with a marginal cost starting at 28.9 €/MWh for the most efficient type of power plant and ending with 42.9 €/MWh for the least efficient. Gas turbines start at 56.4 €/MWh and then there is a steep slope up to the more expensive open cycle turbines, which are only used as reserve power. The highest marginal cost for those is 138.7 €/MWh. The minimum and maximum marginal cost for gas turbines and conventional power respectively are used as input values in the model. Between these points, we assume a linear relationship between marginal cost and volume produced which gives us a good estimation of the Danish marginal cost curve.

We have made one exception to the above reasoning. That is because the UK has more efficient gas turbines than the Nordics (Noothout, Koornneef, de Jager & Klaassen, 2013, p. 63). The most efficient gas turbine is assumed to have an efficiency of 60% (as the most efficient one in table 1) which yields a marginal cost of 46.2 €/MWh as a starting point for the cost curve.

Appendix 2, input variables

Input variable	Description	Base Case	Dry case	More wind	More wind less nuclear	Specialization	Norway dry	Norway base
D	Hourly demand	Actual consumption 2012 for UK, the Nordics and Norway Respective						
Wcap	Installed wind capacity 2012	Nordics: 7754 MW, UK: 7060 Mw		Nordics: 22529 MW UK:32 500 MW		N:22529MW UK:7060MW	NO 705 MW UK: 7060 MW	
Ncap	Installed nuclear capacity 2012	Nordics 12021 MW, UK 9946 MW			Nordics 2685 MW UK:9946MW		Norway - UK 9946 MW	
CHP ind	Total CHP industry production 2012	Nordics 16 942 192 MWh, UK -					Norway -, UK -	
CHP heat	Total CHP district heating production 2012	Nordics 40 353 710 MWh, UK -					Norway -, UK -	
Hydro prod min	25% of maximum capacity 2012	Nordics 12459 MW, UK 387 MW	Nordics: 10342 MW, UK: 387 MW	Nordics 12459 MW UK 387 MW			NO 6197 MW UK 387 MW	NO 9189 MW UK 387MW
Hydro prod max	83% of maximum capacity 2012	Nordics 41364 MW, UK1286MW	Nordics: 34332 MW,UK:1286 MW	Nordics 41364 MW UK 1286 MW			NO25017MW UK1286MW	NO30509MW UK1286MW
Hydro price min	Minimum share of hydro capacity used	Set in order to match 2012 production and maximize producer revenues						
Hydro price max	Maximum share of hydro capacity used	Set in order to match 2012 production and maximize producer revenues						
MaxcapEx	Hourly max export capacity 2012	For Nordics, transmission capacity to DE and NL. For UK, transmission capacity to FR and NL.					For NO, transmission capacity to Nordics and NL. For UK, transmission capacity to FR and NL.	
MaxcapIM	Hourly max import capacity 2012	For Nordics, transmission capacity to DE and NL. For UK, transmission capacity to FR and NL.					For NO, transmission capacity to Nordics and NL. For UK, transmission capacity to FR and NL.	
Pf	Hourly price 2012 for foreign countries	Hourly prices for DE, NL and FR 2012					Hourly prices for Nordics excluding NO 2010, estimated hourly prices based on 2012 and average prices for 2012 for FR and NL.	
a	Constant enabling iteration process	3						
Fossil cost min	Lowest marginal cost for gas an conventional power	Conventional 28.9 €/MWh for both countries, Gas 56.4 €/GW for Nordics and 46.2 for UK.				UK:Conv. 28, Gas46,2€/MWh	Conventional 28.9 €/MWh for both, Gas 56.4 €/GW for NO and 46.2 for UK.	
Fossil cost max	Highest marginal cost for gas an conventional power	Conventional 42.9 €/MWh and Gas 138.7 €/GW for both countries, for Nordics and 46.2 for UK.				UK:Conv. 36,5, Gas56,4€/MWh	Conventional 42.9 €/MWh and Gas 138.7 €/GW for both countries, for NO and 46.2 for UK.	
Fossil prod max	Installed capacity conventional power and gas turbines 2012	Nordics:7407 MW conventional, 4121 MW Gas UK:33713 MW conventional, 35320 MW Gas					UK:33713 MW conv., 35320 MW gas NO: 1071 conv., 576 MW gas	
Y	Maximum transmission capacity the interconnector	1400 GW						

Bench marks variable	Value in Nordics	Value in UK	Value in Norway
Total wind production 2012	19 496 760 MWh	20 775 449 MWh	-
Total nuclear production 2012	83 456 000 MWh	63 949 205 MWh	-
Total hydro production 2012	237 906 476 MWh	5249 671 MWh	142 810 000 MWh
Total hydro production 2010	196 603 020 MWh	5249 671 MWh	117 138 885 MWh