the economic and welfare impact of increasing transmission capacity in the electricity market: the case of skagerrak iv

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Abstract

In this paper we present an empirical analysis of the economic and welfare impact of increasing the transmission capacity by taking Skagerrak 4 with 700 MW between South Norway (NO1) and West Denmark (DK1) as a case study. We examine the impact of increasing the transmission capacity on electricity prices, trade and overall welfare gains using simulation modeling. Moreover, we explore the potential for further expansions. To address these issues, we first developed an empirical model for both market using hourly data set from 2004 to 2010. For the simulation part, we took different years and initial reservoir levels. Our findings show that the transmission capacity upgrade amplifies the power flows from low cost generation area (NO1 in wet year and DK1in dry year) to high cost generation area (NO1 in dry year and DK1 in wet year). With regards to prices, following the path of export, NO1's price increases for high inflow and reservoir level as well as peak hours and it decreases for low inflow and reservoir level. In contrast, price in Dk1 decreases when NO1 has more water and during peak hours. During off-peak load hours, price increases as DK1 increases its exports during these hours leading to price convergence. However, we still have price spikes during wet year. From net welfare point of view, the results show that upgrading the interconnection improves social welfare when NO1 has high inflows. For a dry year, transmission capacity upgrade leads to a net welfare loss even if DK1's welfare improves when NO1 has high initial reservoir level. Further upgrading the transmission capacity by 1400MW has still a room for welfare improvement in wet year. However, upgrading the capacity by 2100MW has no significant impact on net welfare.

Keywords: transmission capacity expansion, simulation modeling, initial reservoir level, inflow, price volatility, congestion rent, net welfare

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1 Introduction

1.1 Background

Restructuring the electricity market is based on the idea of creating competition in the wholesale and retail market which leads to efficient outcomes both in ways of production as well as electricity price (Borenstein and Bushnell, 2000, Joskow, 2008). Deregulating the market makes trade attractive and beneficial as it facilitates the access to low-cost generation by consumers located in high-cost generation areas. In addition, the fact that electricity cannot be stored and it can be produced with a wide range of alternative technologies magnifies electricity trading advantage of deregulating the market. Recognizing these facts, EU's deregulation policy called for deregulation and competition in electricity and gas markets by July, 1 2007 at the latest (EU, 2003). Accordingly countries started opening their borders for trade.

Depending on the complementarities between the interconnected region's demand and supply profile, the major benefits of regional electricity trading include improved security of supply, economic efficiency, and environmental protection. It improves security of supply since it allows different fuel mix generators to participate in the market. It also leads to economic efficiency by enhancing competition in the interconnected markets. In addition, the current EU environmental policy aims to reduce greenhouse gas emissions by 80-95% by 2050 compared with 1990[1]. Thus for electricity producers it means they have to produce electricity not only in a cost effective but also environmentally friendly ways.

Despite the visible gain from trade, unlike other tradable commodities, electricity is constrained by capacity of its transportation. Recently, different market reports show that the transmission lines are congested and there are significant price differences between

[1] For more information, see Council of the European Union (2011).

regions[2]. For instance, in the Nordic market, market splitting was forced 72% of the time in 2011 (Nordic market report, 2012). This shortage of transmission capacity creates barriers to trade between countries and makes it difficult to harvest all the gain.

Moreover, most of the electricity transmission grids in Europe were built in 1950s and 1960s and at that time the main purpose of cross-border electricity interconnections was to ensure security of supply and enhance system (Küpper et al., 2009, Schweppe et al., 1988, Wu et al., 2006). For that reason, strengthening electricity connections and reducing transmission bottlenecks has become one of the top agendas of energy policy makers. Many studies also showed that, in the deregulated electricity market, it is unarguable fact that the capacity of the transmission line plays an important role for the establishment of competitive wholesale electricity markets (Borenstein and Bushnell, 2000, Joskow and Tirole, 2000, Leautier, 2001).

Accordingly, the European Commission (EC) has been taking steps to promote new investments in cross-border transmission lines. The first step towards a more integrated perspective has been taken by ENTSO-E's Ten Year Network Development Plan (TYNDP). This process is further assisted by the EU Infrastructure Package (EIP) which provides a comprehensive approach to EU grid expansion that builds and incorporates existing initiatives. In line with the EU policy, countries have already started taking actions to increase their cross-border transmission capacity. Countries of the Nordic regions are among these countries.

1.2 Statement of the problem

This paper focuses on the Nordic region in particular the interconnection between South Norway (NO1) and West Denmark (DK1), Skagerrak 4. Ten years ago, the Nordic region which includes Norway, Sweden, Finland and Denmark started the first integrated power

[2] When transmission capacity of an interconnection linking national transmission networks is insufficient to accommodate all electricity flows resulting from international trade requested by market participants, it is said that the interconnection is congested

exchange market without border tariffs for spot trading; the Nord pool. Differences in generation mix resulted in interdependences between these markets. For example, the total volume traded at Nord Pool Spot in 2011 was about 78% of the total Nordic electricity consumption (Nordic Market report, 2012).

As the transmission lines between the countries become congested, the markets are split into different price areas. Thus, to continue encouraging competition between these national markets and insuring security of supply, the TSOs are investing on upgrading and building new transmission lines.

Many literatures have addressed the problems of congested transmission lines in the Nordic region, for example (Brejnholt, 2009, Mirza and Bergland, 2012, Steen, 2004). However, little empirical works have attempted to analyze the advantages of transmission capacity expansion. Among these studies, we can mention (Parail, 2009), which investigated the impact of NorNed, the connection between Netherlands and South Norway, using time series analysis after the connection is operational. Although this study is an important step toward empirically modeling of the welfare impacts of transmission line expansion, we believe the electricity market should be modeled using Structural modeling approach as demand and supply interacts to give the market clearing price. Moreover, Teusch et al.(2012) provides a more theoretical approach on the advantages of the connection between the Nordic and other northern EU member states.

One of the congested corridors within the Nordic region is the link between South Norway (NO1) and West Denmark (DK1). To address this bottleneck, a further 700 MW upgrade, Skagerrak IV, is expected to be operational in 2014. It is financed by Energinet.dk (Danish TSO) and Statnett (Norwegian TSO). This study empirically investigates the welfare impacts of this planned upgrade and explores the potential for further expansions. The project aims at relieving the congestion between the two countries and takes advantage of the complementary effect of the hydro dependent Norwegian market with the thermal and wind power generation Denmark.

What makes this study interesting is that, Norway has more than 90% of its electricity production from hydropower and most of it is storable in reservoirs. While Denmark produces most of its electricity from thermal, but recently wind power's contribution has increased. In fact, there were times when Denmark's electricity market operated with prices down to zero, and even negative prices, because of too much production compared to the demand because the TSO has to incorporate the wind as it blows (Førsund and Hjalmarsson, 2011). Thus, this upgrade can facilitate the flow of electricity between the dynamic hydropower of Norway and the Static thermal power of Denmark while creating room for the proper utilization of wind power.

Examining the new transmission capacity in terms of its welfare enhancing value enables us to exploit the gains and losses of both consumers and producers and investigate the extent to which the two countries prices converge. We answer questions like, one; will the market become more competitive and efficient? Two, what would be the price change in both countries? How volatile are the prices? Three, what is the impact of this upgrade on consumer and producer surplus as well as the overall welfare?

To address these research questions, we developed an empirical model for both markets using the data set from 2004 to 2010. Then, we applied the estimated model into our simulation model in which we took four different years as a base case scenario, one wet year (2007), two average years (2005 & 2008) and one dry year (2006). These years are analyzed for three different initial reservoir levels (IRL) in NO1: 60%, 70% and 80%. Finally, we investigated potential social welfare improvements by further upgrading the interconnection by 1400MW and 2100MW.

1.3 Review of related studies

1.3.1 Electricity trade

A number of studies support the above advantages of electricity trade. For instance; Swan et al. (1999) showed the competition enhancing impact of the Queensland – New South Wales interconnection. Unger and Alm (2000) and Teusch et al. (2012) showed that electricity trade provides cost effective opportunities to fulfill their co2 obligation for the Nordic countries. Von Der Fehr and Sandsbråten (1997) analyzed the gain from electricity trade arising from the exploitation of technological complementarities between hydro and thermal systems for the Nordic countries. Bajpai and Singh (2004) showed that electricity trade provides risk hedging associated with price volatility for India. Malaguzzi Valeri (2009) analyzed the low price and supply security impact of additional electricity interconnection between Great Britain and Ireland. The analysis of Finon and Romano (2009) also shows that market integration will lead to lower price consumers living in countries with high variable cost capacity at the expense of consumers living in countries of low cost capacity. Nepal (2011) quantitatively examined interconnections in the Irish Single Electricity markets and concluded that larger interconnector capacity promotes competition, improve security of supply and mitigate price volatility. Parisio and Bosco (2008) evaluated the welfare effect of cross border trade and showed that cross-border trade may lead to price convergence between countries

1.3.2 Consequences of congested transmission line

Transmission capacity has a direct impact on the level of competition among generators in different markets which are manifested in terms of market power and higher electricity prices. Accordingly, congested transmission line leads to economically inefficient outcomes. It impedes the ability of consumers to choose their suppliers freely and it also creates an opportunity for suppliers to exercises market power[3]. This results in consumers located at high cost areas paying high price. Several studies support this argument, for example, Stoft (2002) showed that transmission bottlenecks can lead to the exercise of market power which in turn increases the cost of electricity for consumers. Joskow and Tirole (2000) and Nasser (1997) showed that in the presence of transmission bottleneck, producers try to exercise market power by biding prices above marginal cost . In the same line of argument, Borenstein and Bushnell (2000) showed that limited transmission

[3] Market power is defined as the ability of seller to profitably maintain prices above competitive levels for a significant period of time (Shahidehpour et al.;2002,Shahidehpour &Alomoush, 2001).

capacity give a firm the incentive to restrict its output in order to congest transmission into its area of dominance. Moreover, Steen (2004) and Mirza and Bergland (2012) applied structural modeling approach to study the Nordic electricity market and , found out that the producers exploit some limited market power within the day or hours when binding bottlenecks appear.

1.3.3 Advantages of increasing transmission line capacity

From our discussion so far we have seen the advantages of cross border electricity trade and the fact that transmission congestion impedes the advantages a given country could gain from trading. Thus having adequate transmission capacity is unarguable fact. The value of transmission network was first uttered by Schweppe et al. (1988) that developed the concept of nodal pricing of electricity: at every instant, prices at two locations on the grid may differ, the difference reflecting the impact of marginal losses and transmission constraints between these two locations. Borenstein et al. (1997) showed how small increase in transmission capacity may lead to substantially lower prices through increased competition. In the same line of argument, Nasser (1997) also suggested that expansion of transmission capacity is necessary to alleviate existing local market power. Leautier (2001) illustrated that the transmission grid holds the keys to an important share of the economic value created by the restructuring of the power industry. He showed that an increase in transmission capacity has an effect of making cheaper power available and increasing competition among generators. Kleit and Reitzes (2006) estimated the potential gains that can be achieved through transmission expansion in moving power from lower-priced to higher-priced regions. Haas et al. (2008) analyzed the relevance of cross-border transmission lines for competition in an integrated continental European electricity market in the short run. Hesamzadeh et al. (2008) adopted a Three-Stage Model for transmission augmentation in restructured electricity markets to show that an increase in transmission capacity can have two benefits for the electricity market; firstly, efficiency benefit in terms of improving the social welfare of the electricity industry, and, secondly, competition benefit which leads to increasing competition among generating companies. Parail (2009) investigated the impact of NorNed, the connection between Netherlands and South Norway, on price volatility and the result shows that the connection has contributed to reduction in volatility in Netherlands electricity price, though the effect is not dramatic but in the case volatility of Norway´s electricity price, it shows no statistically significant difference. Similarly Newbery (2006) analyzed the impact of the UK and the Netherlands interconnector on price levels and volatility.

1.4 Objective of the study

The general of objective of the study is to assess the impact of the new interconnector, Skagerrak 4 between Southern Norway and Denmark,

Specifically, the study aims

1. to see the impact of the connection on price for both peak load and off-peak load hours.
2. to see its impact on electricity trade between the two countries.
3. to assess the overall welfare gain from the new transmission capacity.
4. to investigate whether or not we need further transmission capacity upgrades.

1.5 Organization of the paper

The remaining part of the paper is organized as follows: Chapter 2 gives an over view of the Nordic electricity market. Chapter 3 sets out the theoretical framework of the paper. Chapter 4 goes through the data and the methodology used. Chapter 5 is provides result interpretation and discussions. Chapter 6 concludes the study.

2. The Nordic Power Market

As our study focuses on the Nordic region, this section of the paper discusses about the structure of the Nordic electricity market, most importantly the current transmission line capacity in the region and the proposed plans for capacity expansion.

2.1. The operation of the market

The Nordic electricity exchange Nord Pool Spot is known to be one of the efficient and largest electricity market, for Example see (Amundsen and Bergman, 2006, Bergman, 2003, Bye and Hope, 2005). And it covers Denmark, Finland, Sweden and Norway and has been open to competition since 1994[4] . These countries implemented electricity market reform in the Nordic countries In particular, the reform process in the Nordic countries has included both the elimination of border tariffs and a set of other measures aimed at establishing a multinational integrated market for electricity.

The total volume traded at Nord Pool Spot in 2011 was over 294 TWh, compared to approximately 305 TWh in 2010. The decrease from 2010 can be explained by a 3.8 percent decrease in overall consumption (Nordic Market report, 2012).Nord Pool Spot offers both day-ahead and intraday markets.

Day-ahead trading

Elspot is Nord Pool Spot's day-ahead auction market, where electrical energy is traded. Players, who want to buy energy from Elspot, must send their purchase bids to Nord Pool Spot at the latest at noon the day before the energy is delivered to the grid. Correspondingly, participants who want to sell energy to Elspot must send their sale offers to Nord Pool Spot at the latest at noon the day before the energy is delivered to the grid (i.e. gate closure is 12 o'clock).

[4] Estonia joined the Nordic market as one of the price areas in spring 2010.

The System Price (the unconstrained market clearing price) is the theoretical, common price; we would have in the Nordic area, if there were no grid bottlenecks: if there were no grid bottlenecks, we would have one common, Nordic day-ahead price for each hour. But when grid congestion develops, two or more area prices are created and the total geographical market is divided into a number of bidding areas

Intraday market

Elbas is a continuous intraday market for trading power across the Nordic region, Germany and Estonia. It plays an important role by functioning as a balancing market to the Elspot day-ahead market since the time span between the day's Elspot price-fixing and the actual delivery hour of the concluded contract is quite long(36 hours at the most) .Elbas also offers opportunities for risk reduction as well as increase profit.

Financial Market

Financial contracts are used for price hedging and risk management. In the Nordic region financial contracts are traded through Nasdaq OMX commodities. The contracts have a time horizon up to six years, covering daily, weekly, monthly, quarterly, and annual contracts. The system price calculated by Nord Pool Spot is used as the reference price for the financial market.

Transmission system operators (TSOs)

A system operator is responsible for the security of supply in his area. A system operator has to be a non-commercial organization, neutral and independent with regard to the market members.

In the Nordic countries, the system operators have the responsibility for both the security of supply and the high-voltage grid (the transmission grid). This means TSO has the task of ensuring the system always maintains the balance between supply and demand. In addition it is also responsible for planning and financing of necessary expansion of the national grid. The Nordic transmission system operators (TSO) are Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland) andEnerginet.dk (Denmark).

Since the national grids are interconnected across the borders, the TSOs have a cooperative organization Nordel[5], which gives recommendations on expansions that are advantageous for the common market.

2.2. Consumption of electricity in the Nordic region

Electricity consumption in the Nordic region is relatively high in comparison with other European countries. This is due to the influence of cold winters in combination with heated houses and the relative high proportion of energy intensive industries. The following table shows electricity consumption in the Nordic countries by category in GWh.

	Norway	Sweden	Finland	Denmark
Industry	42080	51419	36209	8510
Transport	657	2438	716	395
Residential	36359	40946	22047	10096
Commercial and public services	24133	26744	17238	10705
Agriculture/Forestry	1915	1827	950	1876
Fishing	178	0	0	0
Total	105322	123374	77110	31582

Table 1: Nordic countries consumption by category in GWh.

(source: The Swedish Energy Agency, 2009)

Sweden had the largest share of the total consumption (105322 GWh) followed by Norway (123374 GWh), Finland (77110 GWh) and Denmark (31582 GWh). Electricity consumption in the Nordic region varies widely due to specific conditions in each country. But as we can see from the above table economic growth and climate conditions are the most important consumption influencing factors (Nordic market report, 2012).

[5] Nordel has been replaced by European Network for Transmission System Operators for Electricity(ENTSO-E) as of 01.07.2009

2.3. The production of electricity in the Nordic region

The Nordic region has a mixed of generation sources-Hydro, thermal and nuclear, with a very high share of hydropower. Hydropower accounts for virtually all of the Norwegian and nearly half of the Swedish generation capacity, making the level of precipitation vital when calculating and analyzing potential generation levels. The influence of reservoir levels in electricity futures prices at Nord Pool has been studied by (Botterud et al., 2002, Førsund and Hjalmarsson, 2011, Førsund and Hoel, 2004, Gjolberg and Johnsen, 2001).

As can be seen in Table 2, however, the national systems exhibit significant differences with respect to the relative shares of various generation technologies with most of the hydropower capacity located in Norway and Sweden. CHP is the second largest generation source followed by nuclear power.

	Denmark	Finland	Norway	Sweden	Nordic region
Installed capacity (total)	13540	16713	31714	36447	98414
Nuclear power	-	2716	-	9363	12079
Other thermal power	9582	10651	1062	7988	29283
-condensing power	1590	2155	-	1623	5368
-CHP, district heating	7118	4300	-	3551	14969
-CHP, industry	674	3362	-	1240	5276
-Gas turbines	200	834	-	1574	2608
Hydropower	9	3149	30140	16197	49495
Wind power	3949	197	512	2899	7557

Table 2: Nordic generation capacity (MW) by power source, 2011

(Source: Nordic market report, 2012)

The region has a total of 98,414MW installed capacity for power generation and the total power generation in the Nordic region in 2011 was 370 TWh, 1 percent decrease compared to 2010 (Nordic market report ,2012).

2.4. Inter-connector capacity and bottlenecks in the Nordic region

The Nordic transmission grid is part of the transmission network in the North-Western Europe. The Nordic market is also connected to Germany, Poland, Estonia and Russia and the Netherlands.

Electricity is transported from where it is generated to where the load is through the transmission line. But demand may sometimes exceed the available physical capacity of the transmission system. When the inter-connector capacities were insufficient, the Nordic electricity market would frequently disintegrate into a set of separate national markets. Thus, as we mentioned earlier, the system price is more like a theoretical price which occurs if there were no grid bottlenecks.

TSO of each country decides to how many areas the country is divided into. The number of Norwegian bidding areas can vary, today there are five bidding areas. Eastern Denmark and Western Denmark are always treated as two different bidding areas. Finland continues as one bidding area. Sweden was divided into four bidding areas on 1 November 2011.

And the transmission grids between these price areas have limitations on the amount of electricity that can be transferred. The following table presents the current inter-connector capacities between the Nordic countries.

Countries	**One way (MW)**	**The other way (MW)**
Sweden/Norway	*Sweden->Norway*	*Norway->Sweden*
NO4-SE1	*600*	*700*
NO4-SE2	*300*	*200*
NO3-SE2	*100*	*600*
NO1-SE3	*2095*	*2145*
Finland/Sweden	*Finland->Sweden*	*Sweden->Finland*
SE1-FI	1500	1100
SE3-FI	*1350*	*1350*
Sweden/Denmark	*Sweden->Denmark*	*Denmark->Sweden*
DK1-SE3	680	740
DK2 – SE2	1300	1700
Denmark/Norway	*Denmark->Norway*	*Norway->Denmark*
DK1-NO1	1000	1000

Table 3: Transmission capacity between countires in the Nordic Region

(Source: Nord pool website)

As can be seen in the table, the inter-connector capacity between Norway and Sweden is quite high and the connection between Norway and Denmark is low in comparison to the corresponding capacities between the other countries.

Congestion management

According to the EU's regulatory framework, market-based methods shall be used to manage transmission limitations. In line with the EU's framework, Different countries use different methods to handle congestion. In the Nordic region the capacity limits of the transmission grid in the market area are auctioned implicitly and are handled through two different mechanisms; market splitting between bidding areas and counter purchase within bidding areas (Bjorndal et al., 2003, Glachant and Pignon, 2005, Kristiansen, 2004).

In addition to calculating day-ahead prices, the Elspot market is also used to carry out day-ahead congestion management. By means of market splitting, the Nordic electricity exchange Nord Pool Spot carries out the day-ahead congestion management on the interstate links between Denmark, Norway, Sweden and Finland. In Finland and Sweden the system operators also manage transmission bottlenecks within the respective country by means of countertrade system while an area pricing system is used in Norway.

In 2010, the Nordic area had a common power price for 18 percent of the time. This is a reduction of eight percentages in relation to 2009. During 2011, the Nordic countries had a common electricity price during 26 % of the time. This is an increase of just over 8 percentage points compared to 2010, when the electricity price was common during 18 % of the time. The increase is due to an improved hydrological balance, slightly greater availability of nuclear power and reduced demand for electricity in the Nordic countries (The Swedish electricity and natural gas markets, 2011).

Congestion rent

Transmission bottlenecks among different bidding areas give rise to congestion rent, which is the price difference between a high and a low bidding area multiplied by the volume transmitted. The bottleneck revenues for any particular hour are made up of the price difference between a high- and a low-bidding area multiplied by the volume transmitted.

In the Nordic region congestion rent is derived from the Elspot area prices and the flow between areas. It is collected by Nord Pool, which then distributes it among the Nordic system operators in accordance with agreements made in this regard. The TSO's are using the revenues for investments to upgrade and strengthen the transmission lines

Plans for upgrading the transmission capacity

Transmission congestion has a cost since some high cost generation is dispatched in favor of lower cost generation that would otherwise be used. Thus, for the power market to function efficiently, the transmission capacity among the Nordic countries needs to be strengthened. The Nordic grid master plan (2012), states three main drivers for system development in the Nordic region. Which are market integration, RES and conventional (nuclear and other thermal) generation integration and security of supply accordingly, there has been progress in upgrading the transmission line with in the Nordic region and with the neighboring countries (Nordic Grid Development Plan 2012).

In June 2004, Nordel has agreed to priorities five investment projects in order to improve transmission capacity. Three of these reinforcements are now in operation, while the remaining two are under construction with expected commissioning in 2014. These are;

1- Fenno – Skan 2 -HVDC-link (800 MW) between Sweden and Finland. In operation since December 2011.

2- Nea – Järpströmmen- 420 kV AC line between Norway and Sweden. In operation since September 2009.

3- Cross-section 4 in Sweden - HVDC-link (2*720 MW) in southern Sweden. It is under construction and expected to be operational by 2015.

4- Great Belt - HVDC-link (600 MW) between Eastern and Western Denmark. In operation since September 2010.

5- Skagerrak IV- HVDC-link (700 MW) between Denmark and Norway. It is under construction and will be opened by 2014.

In 2008 three more projects were added to the Nordic Grid Master Plan;

1- Sweden – southern Norway (Hasle cross-section)- HVDC-link (2*720 MW) between Norway and Sweden. It's expected to be opened around 2018-2022.

2- Sweden – Norway north-south axis- 420 kV AC line between Ørskog and Sogndal. It is under construction and expected to be open by 2015.

3- Arctic region- 420 kV AC line between Ofoten – Balsfjord – Hammerfest in northern Norway. Expected to be operational by 2018-2019.

In 2009 the Nordic TSO's planned together with Baltic States TSO's for further integration of the Nordic countries with neighboring countries.

1- Estlink 2- HVDC-link (650 MW) between Estonia – Finland. It is under construction and expected to be opened by 2014.

2- NordBalt - HVDC-link (700 MW) between Lithuania and Sweden. Expected to be operational around 2015-2016.

3. Theoretical framework

In the previous chapter, we saw that in the Nordic electricity market equilibrium price is formed according to demand and supply. Under this chapter, the paper, try´s to lay down the theoretical framework based on what (Forsund, 2007) developed about trade between Hydro and Thermal. Since it particularly fits our case, which is electricity trade between hydropower with reservoir capacity (Norway) and thermal system (Denmark). This will be the base for the empirical investigation in the coming chapters. And based on the theory, the paper will also develop hypothesis to be tested in the coming chapters.

The cooperative optimization problem with reservoir and volume of trade constraints is given as follows;

$$\text{Max} \sum_{t=1}^{T} \left[\int_{Z=0}^{x_t^H} P_t^H(Z)dZ + \int_{Z=0}^{x_t^{Th}} P_{Z=0}^{Th}(Z)dZ - c\left(e_t^{Th}\right) \right]$$

Subject to:

$$x_t^H = e_t^H + e_{Th,t}^{XI} - e_{H,t}^{XI}$$

$$x_t^{Th} = e_t^{Th} + e_{H,t}^{XI} - e_{Th,t}^{XI}$$

$$R_t \leq R_{t-1} + W_t - e_t^H$$

$$R_t \leq \bar{R}$$

$$e_{H,t}^{XI} \leq \bar{e}^{XI}\ , \ \ e_{Th,t}^{XI} \leq \bar{e}^{XI}$$

$$e_t^{Th} \leq \bar{e}^{Th}$$

$$x_t^H, x_t^{Th}, e_t^H, e_t^{Th}, e_{Th,t}^{XI}, e_{H,t}^{XI} \geq 0$$

$T, W, R_o, \bar{R}, \bar{e}^{XI}, \bar{e}^{Th}$ given, R_T free, t =1,…….,T

The definition of variables and parameters are:

e_t^H = hydropower

e_t^{Th} = Thermal power

x_t^H = total consumption for Hydro

x_t^{Th} = total consumption for Thermal

$e_{H,t}^{XI}$ = export of Hydro

$e^{XI}_{Th,t}$ = export of Thermal

R_t = water in reservoir at the end of the year

W_t = inflow during the period

$\bar{R}$ = reservoir capacity

$\bar{e}^{XI}$ = transmission capacity limit

$\bar{e}^{Th}$ = capacity limit of Thermal production

T = planning horizon

The objective in this model is the sum over the periods of consumer and producer surplus for both hydro and Thermal[6].

Due to the possibility of storing water the problem is dynamic. The first two constraints are the energy balance in a sense that the export from one country is the other country's import. The third and fourth constraints are reservoir constrains for hydropower, the third constraint shows accumulation of water in the reservoir and the fourth one shows the limited reservoir capacity. The fifth constraint is transmission capacity constraint which is the same in absolute value for import and export. The sixth constraint is capacity limit constraint for thermal production. The seventh constraint is non-negativity constraint.

Then we derive the Lagrangian by substituting the consumptions of the courtiers' from the energy balance in the objective function as follows;

$$L = \sum_{t=1}^{T} \left[\int_{Z=0}^{e_t^H + e^{XI}_{Th,t} - e^{XI}_{H,t}} P_t^H(Z)dZ + \int_{Z=0}^{e_t^{Th} + e^{XI}_{H,t} - e^{XI}_{Th,t}} P_t^{Th}(Z)dZ - c\left(e_t^{Th}\right) \right]$$

$$- \sum_{t=1}^{T} \omega_t (R_t - R_{t-1} + W_t - e_t^H)$$

$$- \sum_{t=1}^{T} \gamma_t (R_t - \bar{R})$$

[6] For Hydro it will be the gross area under the demand curve since we have assumed zero production cost.

$$-\sum_{t=0}^{T} \alpha_{h,t} \left(e_{H,t}^{XIH} - e^{-XI} \right)$$

$$-\sum_{t=0}^{T} \alpha_{Th,t} \left(e_{Th,t}^{XID} - e^{-XI} \right)$$

$$-\sum_{t=1}^{T} \theta_t \left(e_t^{Th} - e^{-Th} \right)$$

The first-order necessary conditions are;

$$\frac{\partial L}{\partial e_t^H} = P_t^H(x_t^H) - \omega_t \leq 0$$

$$\frac{\partial L}{\partial e_{H,t}^{XI}} = -P_t^H(x_t^H) + P_t^{Th}\left(x_t^{Th}\right) - \alpha_{H,t} \leq 0$$

$$\frac{\partial L}{\partial R_t} = -\omega_t + \omega_{t+1} - \gamma_t \leq 0(= 0\ for\ R_t > 0\ )$$

$$\frac{\partial L}{\partial e_t^{Th}}\ = p_t^{Th}\left(x_t^{Th}\right) - C^{\prime}\left(e_t^{Th}\right) - \theta_t \leq 0\left(for\ e_t^{Th} > 0\right)$$

$$\frac{\partial L}{\partial e_{Th,t}^{XI}} = P_t^H(x_t^H) - P_t^{Th}\left(x_t^{Th}\right) - \alpha_{Th,t} \leq 0\left(= 0\ for\ e_{Th,t}^{XI} > 0\right)$$

$$\omega_t \geq 0(= 0 for\ e_t^H > 0\ )$$

$$\gamma_t \geq 0(= 0\ for\ R_t < \bar{R})$$

$$\theta_t \geq \left(= 0\ for\ e_t^{Th} < e_t^{-Th}\right)$$

$$\alpha_{H,t} \geq 0\left(= 0\ for\ e_{H,t}^{XI} < e_t^{-XI}\right)$$

$$\alpha_{Th,t} \geq 0\left(= 0\ for\ e_{Th,t}^{XI} < e_t^{-XI}\right),\ \ t = 1, \ldots T$$

If hydropower is produced the first condition holds with equality, and the period price in hydro is equal to the water value. Furthermore, if hydropower is exported we have from the second condition that the social prices in the countries must be the common equilibrium price as long as the export capacity is not constrained, because according to the complementary slackness condition, the shadow price is zero. If hydropower export is zero, then the shadow price on the export of hydropower constraint is still zero.

According to the second condition the prices in Hydro and Thermal may then differ, with thermal price being less than or equal to the hydropower price. With a lower thermal price the objective function could be increased by transferring a unit of thermal production to hydro. But looking at the fifth condition for thermal export when it is positive, we have that the prices again have to be equal.

If trade constraints are binding, both export and import will be binding for the same period. The second and fifth condition tells us that in such a situation it may be optimal to have different prices between the countries. The price will be lower in the country that is export constrained than in the country that is import constrained.

Based on the model we illustrated above, we will look for qualitative features of the optimal solution using energy ´bathtub´. As hydropower with reservoirs is a dynamic problem, we used a dynamic setting comprising two periods (we chose two periods for simplicity). This qualitative illustration will show us what will happen to electricity price of a given country when Borders are open for electricity trade.

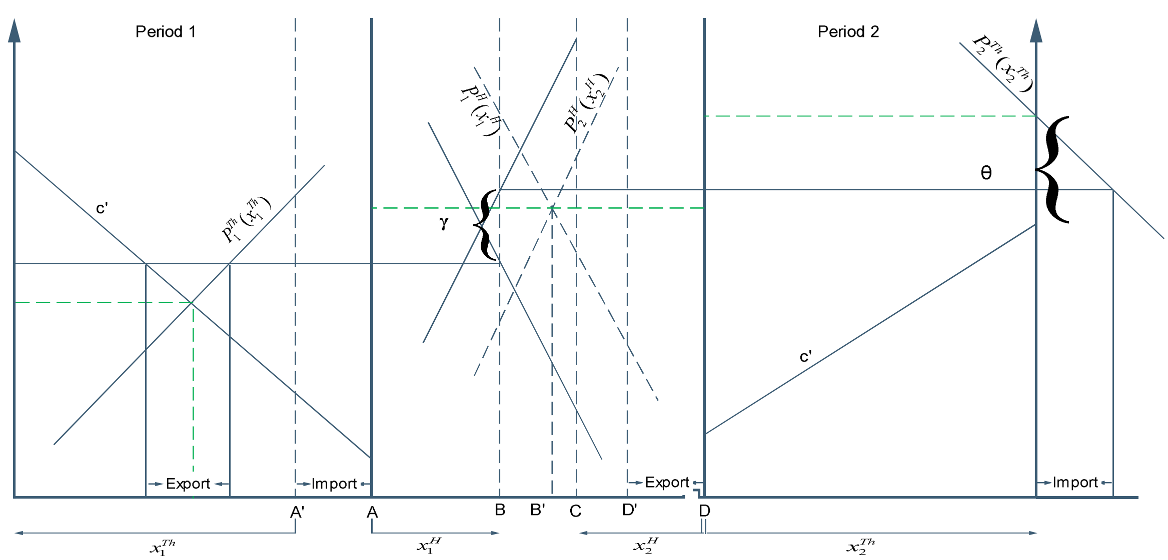


Figure 1: Bathtub of hydropower and thermal

Our bathtub has hydropower in the middle and thermal extensions at both ends. For Hydropower, The demand curve for electricity for period one is anchored on the left hand energy wall created from point A, and electricity consumption is measured from left to right. The demand curve for period two is anchored on the right hand energy wall erected from point D and electricity consumption is measured from right to left. For thermal we depict period one on the left side and demand and supply are read from right to left. While the curves are read from left to right for period two on the right side of the hydro bathtub. The marginal cost functions are the same in both periods.

For simplicity we can start from autarky situation. The Blue doted demand curves erected from A and D show the autarky solution for Hydro. The country specific equilibrium in price and quantities are indicated by the green dotted line. For hydro the autarky prices are equal for the periods. The reservoir capacity BC[7] is not fully utilized in Hydro transferring water from period 1 to period 2 to obtain the social autarky solution. The period 1 price for Thermal is lower than in Hydro, while the period 2 price is higher. The capacity in Thermal is constrained in period 2 and the shadow price is switched on to keep within the limits set by autarky supply at maximal capacity.

Opening up for trade, in period 1 as thermal's autarky price is low, it will export to hydro. The bathtub wall for hydro in period one shifts to the left, from A to A', which is equal to the import to Norway in the period. Since the equilibrium price is slightly lower in period 1 with trade the total electricity consumption is also a little greater. But the use of water in period 1 goes down and the full reservoir BC is transferred to period two.

In period 2 there is an export possibility for Hydro since the Hydro autarky price is considerably lower than that of Thermal. The bathtub wall shifts from D to D', equal to the export from hydropower to Thermal. The prices of both periods are determined by the shifted demand curve (the blue demand curves are the new demand curves) and the

[7] The reservoir is introduced from C to the left to B because our dynamic problem for two periods is how much water to leave to period 2

broken line erected from B representing the maximum reservoir and the start of water available for period 2.

The difference in prices between the two periods is expressed by the shadow price on the upper reservoir constraint. The price in period 2 in Thermal does not decrease sufficiently for spare generating capacity to develop. As we can see from the figure, thermal is still capacity constrained but the shadow price on this constraint is less now. So trade benefits Denmark in period two with lower price compared with autarky. For Hydro we note that the equilibrium price is higher than the autarky price, leading to lower electricity consumption with trade, i.e., less water is used at home due to export

The above explanation excluded an important constraint about the internal country transmission capacity. What happens when there is transmission capacity constraint between the two countries? The following graph is an extension on the above bathtub developed by (Forsund, 2007) to include the impact of transmission line constraint and in a way to show the advantage in increasing the capacity of the transmission line.

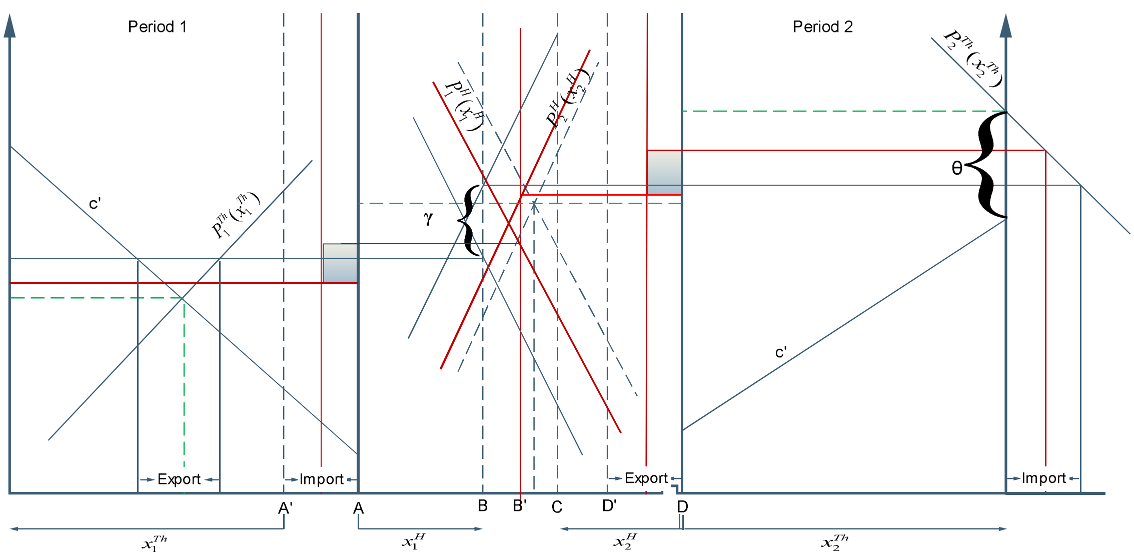


Figure 2: Bathtub model with transmission line expansion

Let us start from period 2 and go backwards. When the transmission line between the two countries is constrained, thermal is forced to decrease its consumption, lower import and higher price in period 2 as indicated by the red line on the graph. The shadow price on thermal capacity constraint will become higher as compared with what it was under free trade. Hydro will export less. The motivation for storing maximal water in period 1 is weakened and the constraint may lead to the reservoir storage not being completely filled as can be seen from the graph only B'C amount of water will be transferred to period 2. The implication is that hydro may consume more water in both periods; the equilibrium price in period 1 will decrease. When we see export from Thermal to hydro, we see a reduction in export, the red vertical line to the right of A', as result of the transmission constraint. This will lead to an increase in consumption for the thermal country.

As the constraint is binding there will be a price difference between the two countries. In Figure 2, the red price lines are the outcomes of the transmission line constraint being binding. Now the import price will be higher by the shadow price on the import capacity constraint. The difference between the sales value of the import and the import cost may be called congestion rent and in our figure it is indicated by the two shaded rectangles.

For hydro, in period 2 we see an increase in consumption under constrained trade compared with free trade scenario as they cannot export as much as they wanted. The reason is that, though limited by the transmission constraint, we are still using some of the water for export. In period 1, there will still be an increase in consumption compared with free trade scenario though import is constraint. Because the reservoir capacity is not fully utilized to transfer water to the next period.

For thermal, in period 2, there will be a decrease in consumption compared with free trade scenario as a result of limited transmission capacity. For period 1, an increase in consumption compared with free trade outcomes because they cannot export as much as they wanted since the transmission capacity is constrained.

When we do over all comparison, In the case of no transmission line connecting the two countries, then domestic electricity producers need to exhaust domestic demand in each hour. Thus, the equilibrium price will be higher for the import constraint country and lower for export constraint country.

If we built a transmission line, then the two countries will start trade and the price will fall as it would be easier to import cheaply produced electricity and import would push the high cost generators out of the market by lowering the system marginal cost. When we further upgrade the grid system and increase the transmission capacity say between these countries it means we are reducing the restriction on the flow of electricity. And we will get a further decrease in price. The reduction in price will continue whenever we increase the transmission capacity until they converge.

3.1. Hypotheses

Based on the specific objectives of our study and the theoretical arguments we gave in the above three subsections; we developed the following hypothesis to be tested in the coming chapters.

Hypotheses one: The size of the transmission line is a very important determinant of competition in electricity market. The higher its capacity is, the more suppliers inject their electricity in to the market and hence compete for consumers. Adequate transmission capacity will also allow power plants to be located in regions that are more economical to do so.

Hypotheses two: Connecting Hydro power with thermal helps in decreasing water spillage when there is high inflow.

Hypotheses three: Increasing the transmission capacity will lead to a decrease in the production as well as price of the high cost production country and an increase in production and price of a low cost country.

Hypotheses four: Consumers' surplus will increase where as domestic Producers' surplus will decrease in the importing country as trade leads to lower domestic electricity price.

4. Data and Methodology

Under this chapter, basing ourselves on the theoretical model of the gain of increasing transmission capacity we discussed in the previous chapter, we developed an empirical structural model for both countries demand and supply for each hour to empirically investigate the effect of increasing the transmission capacity between Norway and Denmark.

On the basis of the estimated demand and supply functions we solved for market equilibrium and then considered the effect of increasing the transmission capacity on the prices and trade between the two countries using simulation. This being said, the next sub-section describes the models we developed for both countries demand and supply.

4.1. The Empirical Models

So in order to see the impact of the increment in transmission line, the paper first modeled demand and supply for the two countries, as the supply and demand is determined simultaneously in the Nord pool.

4.1.1. Supply

On the supply side we need to find an approximation of the marginal cost function and variable that might induce a shift in it.

Supply of Norway

Norway's electricity generation is from hydropower, which highly affected by inflow and reservoir level. The reservoir levels vary during the year as water is moved from summer which is low demand period by snow melting to the high demand periods during the winter. Thus, the major cost component in hydro-power production is the water value.

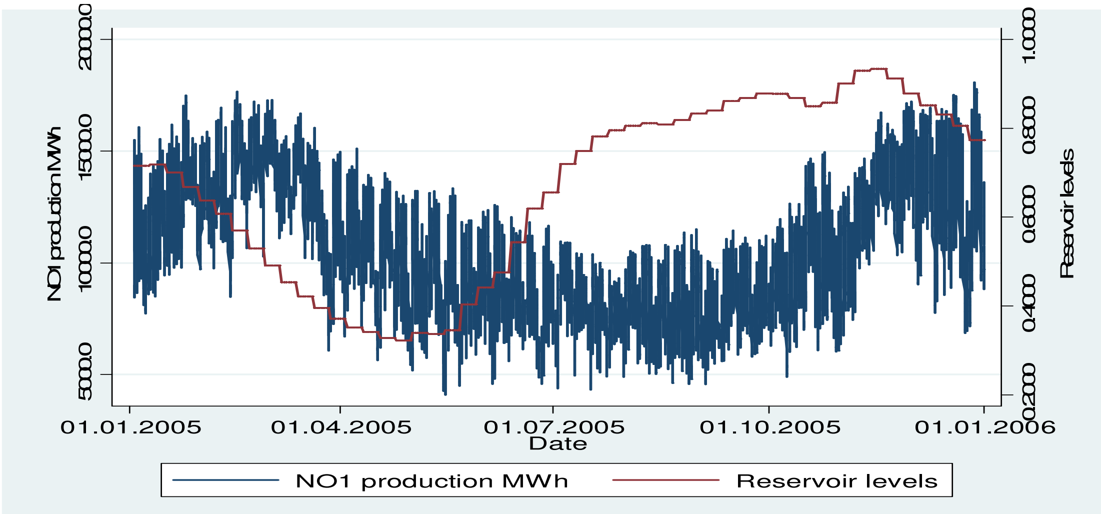


Figure 3: Norway's hydropower production and reservoir level

From the above Figure we can see that during winter there is high electricity production as demand is high during this time. As the result of this we see a decrease in the reservoir level as we are using more water. On the other hand, during summer we see a decrease in production of electricity and an increase in the reservoir level as a result of snow melting.

The double log Inverse Supply function for Norway is modeled as follows;

$$price\_no1 = \beta_0 + \beta_1 prod\_no1 + \beta_2 inflow + \beta_3 rshort + \beta_4 trend + \beta_5 sin + \beta_6 cos + \beta_7 p\_oil + \beta_8 sobl5 + \beta_9 p\_co2 + \beta_{10} d\_co2 + \beta_{11} hr2 + \beta_{12} hr3 + \beta_{13} hr4 + \beta_{14} hr5 + \beta_{15} hr6 + \beta_{16} hr7 + \beta_{17} hr8 + \beta_{18} hr9 + \beta_{19} hr10 + \beta_{20} hr11 + \beta_{21} hr12 + \beta_{22} hr13 + \beta_{23} hr14 + \beta_{24} hr15 + \beta_{25} hr16 + \beta_{26} hr17 + \beta_{27} hr18 + \beta_{28} hr19 + \beta_{29} hr20 + \beta_{30} hr21 + \beta_{31} hr22 + \beta_{32} hr23 + \beta_{33} hr24 + u_t$$

Based on the above argument, we include reservoirs shortage (rshort) and inflow (inflow) to the reservoirs as explanatory variables. Many studies found reservoir level and water inflow in to it to significantly affect electricity price in Nord pool(Botterud and Korpas, 2004, Johnsen, 2001). Crude oil prices (p_oil) and co2 price (p_co2) are added as they affects the overall price of the Nordic region by affection the cost of generation from fossil fuels in the other countries. In addition, we included trigonometric functions (sin cos) to capture the seasonality of price following the argument of Mirza and Bergland

(2012) and Weron (2006). Hourly dummies (hr) and trend are introduced to account for a variation in supply between different hours and generation expansion respectively. We also added government 5-years bonds (sobl5) to see the opportunity cost of investing in the electricity generation. Finally, the variables that shift the demand for electricity have been used as instruments.

Supply of Denmark

Though wind power is providing an increasing part of its energy supply, Denmark relies mainly on conventional thermal power (Eriksen et al., 2002, Giabardo and Zugno, 2008).But as Wind power is stochastic the system operator takes it into account whenever there is a wind blow, it does not affect the producers marginal cost and the producers face the residual demand after taking wind into account. So we looked at the marginal cost curve of centralized and decentralized power generators. The following figure shows how electricity production and thermal power generating sources are correlated.

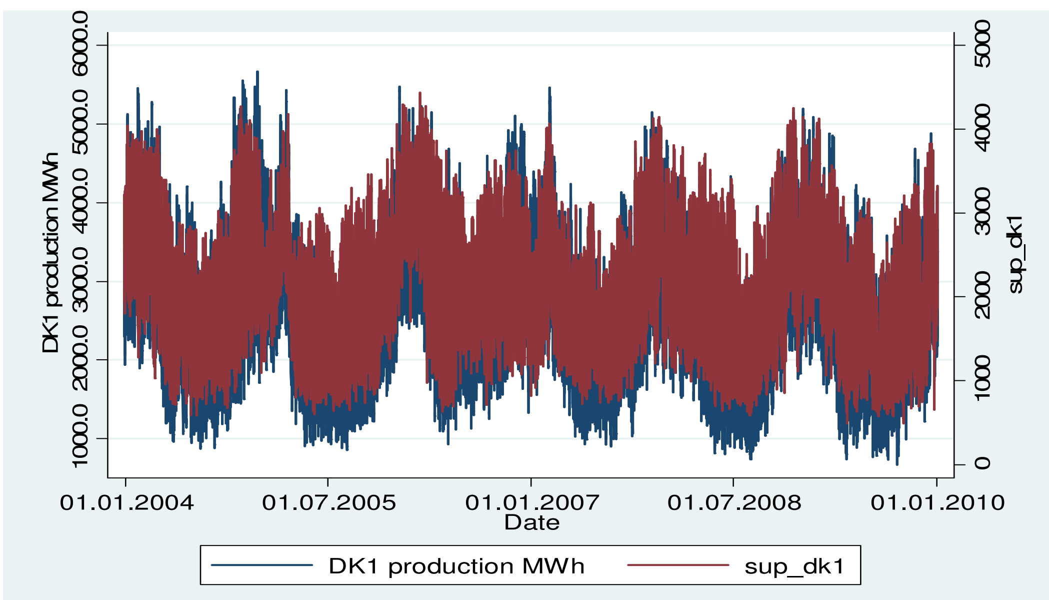


Figure 4: Denmark's thermal production

Accordingly, in our inverse supply function, we included centralized and decentralized electricity production (sup_dk1). Thermal power stations produce electricity by heating water, which turns into steam. To heat the water the power plants uses fuels such as coal, gas and oil. Therefore we included price of gas and coal in our model (pgas p_coal). Our model includes trigonometric functions to capture the seasonality in electricity price and hourly dummies to see the change in production during peak load hours and off peak load hours. Since there is a larger share of fossil fuel power generation in Denmark, we added price of co2 (p_co2) to capture the impact of emission price on the final electricity price. The variables that shift the demand for Electricity has been used as instruments in estimating the supply curve.

The double log Inverse Supply function for Denmark is as follows;

$$price\_dk1 = \beta_0 + \beta_1 sup\_dk1 + \beta_2 pgas + \beta_3 p\_coal + \beta_4 p\_co2 + \beta_5 d\_co2 + \beta_6 trend + \beta_7 tsin + \beta_8 tcos + \beta_9 hr2 + \beta_{10} hr3 + \beta_{11} hr4 + \beta_{12} hr5 + \beta_{13} hr6 + \beta_{14} hr7 + \beta_{15} hr8 + \beta_{16} hr9 + \beta_{17} hr10 + \beta_{18} hr11 + \beta_{19} hr12 + \beta_{20} hr13 + \beta_{21} hr14 + \beta_{22} hr15 + \beta_{23} hr16 + \beta_{24} hr17 + \beta_{25} hr18 + \beta_{26} hr19 + \beta_{27} hr20 + \beta_{28} hr21 + \beta_{29} hr22 + \beta_{30} hr23 + \beta_{31} hr24 + u_t$$

4.1.2. Demand

Demand for Norway

Temperature and day length are the major determinant of electricity demand in Nord pool. Previous studies like (Johnsen, 2001, Lucia and Torró, 2005) found these variables to be significant in their models. Accordingly, we included both linear and squared form of heating degree (hd and hd2)[8] to capture the impact of temperature on electricity consumption Electricity consumption shows annual pattern. Many studies used day

[8] We converted temperature into heating degrees so that we will not loss observation when we convert it to log form as there are negative observations of temperature.

length to capture this annual pattern in electricity consumption (Ericson, 2009, Johnsen, 2001, Johnson and Barz, 1999). But the annual patterns that day length show is not fully aligned with the seasonal pattern in demand during the summer time since the longest day is June 21st but consumption will reach its maximum around the beginning of July because of summer vacation. Therefore, we see about three weeks lag between the two. Thus we added sine and cosine to the model. Previous studies like (Al-Zayer and Al-Ibrahim, 1996, Mirza and Bergland, 2011, Mirza and Bergland, 2012) did the same. Dummy variable for week days (dwkday) is added to capture their different patterns in consumption and dummy variable for hours of a day to see the difference in consumption of electricity between peak load hours and off peak load hours. We also included industrial production index (ipi) to capture additional shifts in electricity demand. Finally, the variables that shift the supply curve have been used as instruments. And we modeled the log-log demand function of Norway as follows;

$$con\_no1 = \gamma_0 price\_no1 + \gamma_1 hd + \gamma_2 hd2 + \gamma_3 dtime + \gamma_4 ipi + \gamma_5 dwkday + \gamma_6 trend + \gamma_7 tsin + \gamma_8 tcos + \gamma_9 hr2 + \gamma_{10} hr3 + \gamma_{11} hr4 + \gamma_{12} hr5 + \gamma_{13} hr6 + \gamma_{14} hr7 + \gamma_{15} hr8 + \gamma_{16} hr9 + \gamma_{17} hr10 + \gamma_{18} hr11 + \gamma_{19} hr12 + \gamma_{20} hr13 + \gamma_{21} hr14 + \gamma_{22} hr15 + \gamma_{23} hr16 + \gamma_{24} hr17 + \gamma_{25} hr18 + \gamma_{26} hr19 + \gamma_{27} hr20 + \gamma_{28} hr21 + \gamma_{29} hr22 + \gamma_{30} hr23 + \gamma_{31} hr24 + u_t$$

Demand for Denmark

Following the same argument we gave for the case of electricity demand for Norway, temperature and day length are the two most obvious variables that affect Denmark's electricity demand. To capture the effect of temperature we used heating degrees. And for the reason we gave for Norway, we used trigonometric functions instead of day length to capture the annual pattern of demand. We also added dummy variables for holidays, weekdays as well as summer vacation to capture the seasonality in electricity consumption of Denmark. The variables that shift the supply curve have been used as instruments to identify the demand curve .We modeled the log-log demand function of Denmark as follows;

$$cons\_dk1 = \gamma_{0+} \gamma_1 hddk + \gamma_2 hdden + \gamma_3 trend + \gamma_4 tsin + \gamma_5 tcos + \gamma_6 dholi + \gamma_7 dwkday + \gamma_8 ds + \gamma_9 hr2 + \gamma_{10} hr3 + \gamma_{11} hr4 + \gamma_{12} hr5 + \gamma_{13} hr6 + \gamma_{14} hr7 + \gamma_{15} hr8 + \gamma_{16} hr9 + \gamma_{17} hr10 + \gamma_{18} hr11 + \gamma_{19} hr12 + \gamma_{20} hr13 + \gamma_{21} hr14 + \gamma_{22} hr15 + \gamma_{23} hr16 + \gamma_{24} hr17 + \gamma_{25} hr18 + \gamma_{26} hr19 + \gamma_{27} hr20 + \gamma_{28} hr21 + \gamma_{29} hr22 + \gamma_{30} hr23 + \gamma_{31} hr24 + u_t$$

4.1.3. Model for Simulation

Simulations are abstractions of reality and it generally refers to a computerized version of the model which is run over time to study the implications of the defined interactions. All in all, a simulation model is a mathematical model of a system or process that includes key inputs which affect it and the corresponding outputs that are affected by it (Gilbert and Troitzsch, 2005, Robinson, 1994).

In our case, we treat Norway and Denmark as one market and try to find the market equilibrium that clears excess demand .Then we split them and see at their individual prices if it is not within the transmission capacity limit. In order to find the equilibrium price that makes excess demand zero, the paper models excess demand in both countries. Then we tried to show the impact of increase in the transmission capacity using the estimated model as an input for our simulation.

To find the equilibrium price that clears excess demand for both market we estimated the following equations;

Log of price

$$lp = \log(p)$$

Quantity demanded DK1

$$dq = \exp(dcd + dpd * lp)$$

Quantity demanded NO1

$$dq = \exp(dcn + dpn * lp)$$

Quantity supplied DK1

$$sq = \exp(lp - scd)\ /sqd$$

Quantity supplied NO1

$$sq = \exp(lp - scn)\ /sqn$$

Excess demand DK1

$$x = dq + nxd - sq - wpd$$

Excess demand NO1

$$x = dq + nxn - sq$$

Excess demand system

$$x = dqn + dqd + nxn + nxd - sqn - sqd$$

Where:

dcd- Demand function constant for DK1

dpd-demand price coefficient for DK1

dcn-demand function constant for NO1

dpn-demand price coefficient for NO1

scd-supply function constant for DK1

sqd-supply quantity constant for DK1

scn-supply function constant for NO1

sqn-supply quantity constant for NO1

nxd-net export of Dk1

wpd-wind power of DK1

nxn-net export of NO1

4.2. Data and Preliminary test

4.2.1. Source and Nature of data

Source of data

In this study, we use hourly data for the period 2004-2010. The data on price, electricity consumption, production, import capacity, export capacity, import volume and export volume has been obtained from Nord Pool Spot (http://www.nordpoolspot.com/). We use hourly temperature data in Oslo as a proxy for the temperature in Norway, hourly temperature in Aalborg (Aalborg airport) as a proxy for the temperature in Denmark. In the case of Norway, temperature data were obtained from Weather Underground (http://www.wunderground.com/history/). We have used weekly data on reservoir level for southern Norway from the Norwegian Water and Energy Administration, NVE (www.nve.no). We use hourly data on wind and decentralized electricity generation in Denmark from Energinet (www.energinet.dk). Summary of descriptive statistics for the variables we used are given in the table below.

Variable	variable label	Obs	Mean	Std. Dev.	Min	Max
price_dk1	DK1 area price (EUR/MWh)	52752	39.17951	18.59231	0.01	943.04
cons_dk1	DK1 consumption MWh	52752	2400.583	528.1851	442	3716
prod_dk1	DK1 production MWh	52752	2656.859	893.9596	673	5671
price_no1	NO1 area price (EUR/MWh)	52752	34.39854	12.43849	0	100.14
cons_no1	NO1 consumption MWh	52752	9894.513	2318.437	5008	16465
prod_no1	NO1 production MWh	52752	10462.06	3030.718	3191	18705
gen_dk1_cent	DK1 generation of cent	52746	1483.197	562.7905	269.8	3166
gen_dk1_de~t	DK1 generation of decent	52746	611.507	327.7322	140.8	1346.5
temp_osl	Temperature osl	52752	5.713741	8.866095	-23	30
temp_aal	Temperature aal	52752	9.250793	6.894918	-14	30.5
Rlevel	Reservoir levels	52752	0.629243	0.1949874	0.2297	0.9566
Inflow	Weekly inflow (GWh)	52584	1777.941	1294.581	168.062	6892.389
Ipi	IPI for Norway	52752	105.9385	11.24958	68.6	131
sobl5	Government 5-year bonds	52752	3.88445	0.6324327	2.74	5.36
Dlength	Daylength in Oslo	52752	12.35979	4.249139	6.009999	18.71
p_gas	Natural gas price (EUR)	52728	213.6935	85.77999	94.91367	460.455
p_coal	Coal price (EUR)	52728	54.15013	20.65796	28.39882	132.114
p_co2	EUA CO2 spot price	52752	16.03637	8.837352	0	32.6
d_co2	Dummy for no CO2 market	52752	0.186533	0.38954	0	1
p_oil	Brent oil price (EUR)	52752	48.01326	13.60005	22.88996	91.85757
Dholi	Dummy for holidays	52752	0.023658	0.1519823	0	1
Dsumm	Dummy for summer vacation	52752	0.057325	0.2324645	0	1
Dwkday	Dummy for workingdays	52752	0.690628	0.4622392	0	1
Dtime	Daylight in Oslo	52752	0.513289	0.4998281	0	1

Table 4: Descriptive statistics

Nature of data

Electricity price

Electricity price is highly volatile. The reasons for these spikes in price are uncertainty in weather condition and the fact that electricity cannot be economically stored to smooth consumption and production. As this is the inherent characteristics of electricity price many paper indicate the need to take this into account when modeling electricity market (Keppler et al., 2007, Weron, 2006, Weron et al., 2004).

The following graphs clearly shows that both Denmark's as well as Norway's prices are highly volatile.

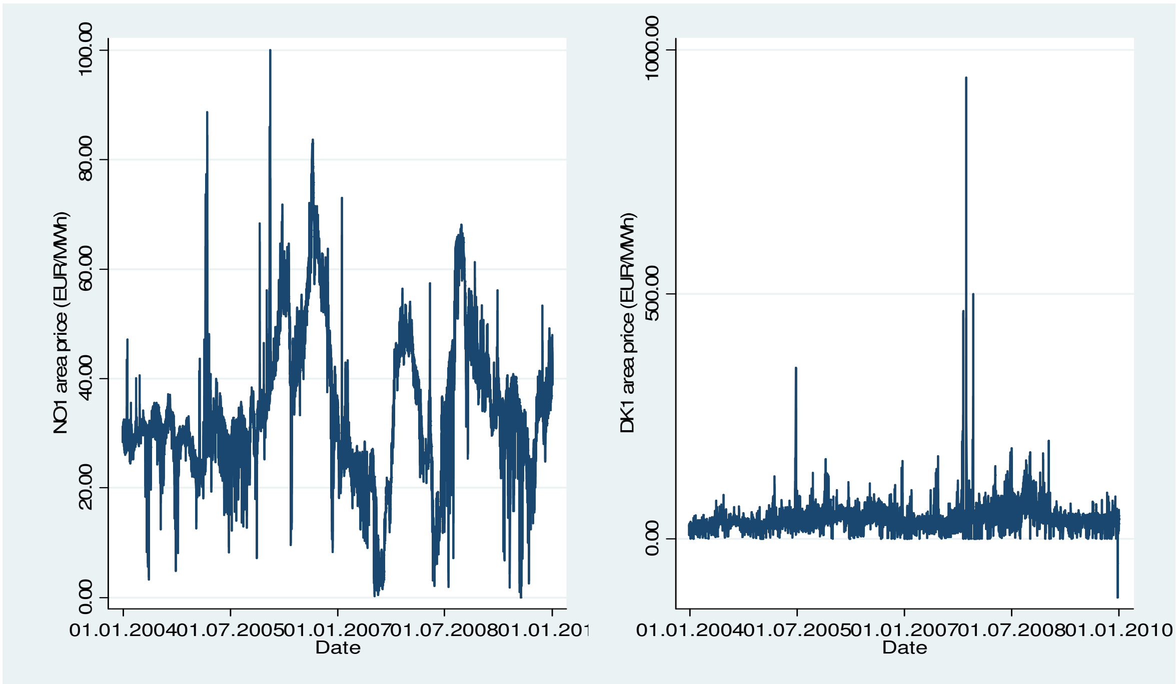


Figure 5: Norway's and Denmark's electricity prices

Electricity consumption and production

As in our previous discussions, uncertainty of the weather condition is the major reason for seasonality of electricity consumption and hence production (Johnsen, 2001, Weron, 2006, Weron et al., 2004). The following figures support the above argument for the time period under study for both NO1 and DK1.

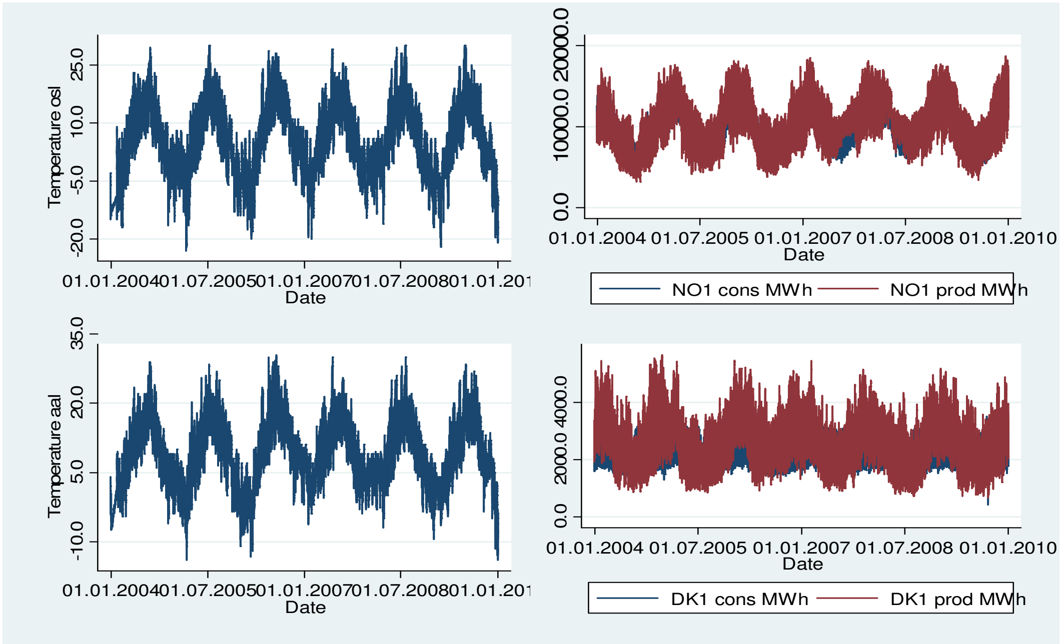


Figure 6: Electricity production and consumption in relation to temperature

As we can see from the above graph, production as well as consumption of both countries fallows the trend of temperature in each country.

4.2.2. Stationarity test

Stationarity is the most important criteria when one is dealing with time series data. Thus, before doing any estimation, it is important to make sure that the variables are stationary. Accordingly, we have applied both Augmented Dicky Fuller (ADF) and Phillips and Perron (PPERRON) unit root test to test for stationarity of our variables. Results from the unit root test have been reported in Table 5.

Variable	ADF	PPERRON Test	
		Z(rho)	Z(t)
Price_dk1	-54.245***	-5015.630***	-51.623
Price_no1	-12.457***	-169.278***	-9.223
Prod_no1	-25.936***	-1556.735***	-28.051
Cons_no1	-17.128***	-670.193***	-18.332
Sup_dk1	-30.464***	-2073.325***	-32.444
Cons_dk1	-35.140***	-3149.130***	-40.037
inflow	-5.819***	-68.497***	-5.849
Sobl5	-1.436	-4.229	-1.436
P_gas	-1.369	-2.939	-1.369
P_coal	-1.797	-4.704	-1.797
P_co2	-1.886	-4.704	-1.886
P_oil	-2.083	-6.668	-2.083
dtime	-69.276***	-6224.242***	-59.395
rshortage	-2.066	-7.306	-2.067
ds	-7.455***	-112.875***	-7.516
Heatd	-12.168***	-400.195***	-14.109
Heatddk	-13.768***	-435.801***a	-14.762
Ipi	-1.749	-4.375	-1.749
ADF Critical Values		PPERRON Critical Values(Z(rho))	
1% 5%	10%	1%	5%
-3.430 -2.860	-2.570	10%	
		-20.700 -14.100	-11.300
***significant at 1%	**significant at 5%	*significant at 10%	

Table 5: Stationarity test

The results suggest that, for all the variables except prices of oil, coal, co2, government bond and industrial price index, the null hypothesis of the presence of unit root is rejected at the 1% level of significance. This implies that most of our variables are I (0) at levels. Price of gas, oil, co2 and coal are included in the model even if they are non-stationary mainly because they are independent variables included in the supply equation to approximate the marginal cost of production. When we come to the reservoir level, this is a variable on which information is collected on weekly basis and we are using an hourly data so we find that the value of this variable changes only after (24*7=168) observations.

4.3. Estimation technique

4.3.1. Structural modeling

Next, we developed an empirical structural model for both countries electricity demand and supply. On the basis of estimated demand and supply functions we will solve for market equilibrium and consider the effect of a change in the transmission capacity using simulation modeling.

As we are studying the system of two equations - supply and demand. In this system, the market price and quantity of electricity sold are jointly determined by the equilibrium of supply and demand.

The model can be written in a following way:

$$Q^d = \alpha_0 + \alpha_1 P + \alpha_2 x + \varepsilon^d$$

$$Q^s = \beta_0 + \beta_1 P + \beta_2 z + \varepsilon^s$$

$$Q^d = Q^s$$

Where $Q^d$is quantity demanded (consumption), $Q^s$is quantity supplied (production), P is price, x is a vector of demand shifters, while z is a vector of supply shifters, and $\varepsilon^d$and ε^s are unobserved demand and supply shifters respectively.

Here, price and quantities are estimated from both equations simultaneously, therefore they are endogenous variables in this system. Because of this simultaneity issue, OLS suffers from bias and will produce inconsistent estimators for α and β (Wooldridge, 2001). Therefore, estimation of supply and demand model requires an alternative method to ordinary least squares. To control for simultaneity bias, one can use instrumental variable approach, including at least one unique instrument in each equation.

The study estimates log-transformed form of supply and demand equations of both countries simultaneously by using instrumental variable such as day time, heating degrees, dummy for summer vacation, industrial price index and dummy for the weekends, export capacity from and to Denmark for supply function of Norway And inflow reservoir shortage and co2 price are used for demand function of Norway. For supply function of Denmark, we used heating degrees, dummy for holidays dummy for summer vacation and export capacity from and to Norway. And finally for the demand function of Denmark we used reservoir shortage and Swedish power generation for nuclear.

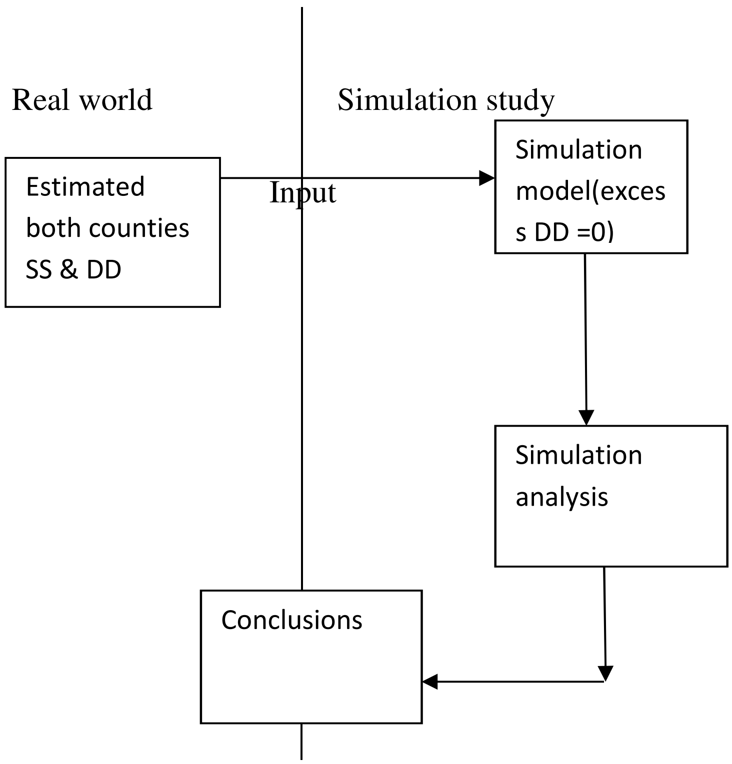
We also did Post estimate diagnostic test for endogenity, over identification and functional form. And our models faced a problem of over identification but we still accepted this as a problem and continued our analysis. Ramesy rest test for functional form indicates there to be a functional form problem in our models but including the quadratic forms enter the model with wrong sign in the case of our supply equations. Thus, the paper did not include them. But it handled the functional form problem we had in the demand equations and they have the right sign so we included them in our demand equation.

To correct the standard estimates, the paper uses the Newey-West standard errors. Which are heteroskedasticity and autocorrelation consistent (HAC) estimates of the standard errors with Lag of 168 and 24 observations for supply and demand respectively so that our statistical inferences will be robust against potential serial correlation and hetroskedasticity (Hayashi, 2000, Newey and West, 1987).

4.3.2. Simulation modeling

After estimating the supply and demand equations, we used MATLAB to do simulation. Under this we tried to estimate the equilibrium price which clears excess demand. We treated them as one market then calculate the system price then we looked at the transmission capacity between them and split the markets if the flow is not within the capacity.

The simulation was used to analyze how changes in capacity will affect price of countries as well as congestion rent, consumption and production. Graphically, what our simulation model does is;



Over all what this study does is to estimate the value of transmission over discrete increases in transmission capacity. That will be like a step process as follows:

1)Using the estimated parameters from STATA , we calculate the system price and the area price using the existing transmission capacity and also using wind , inflow and reservoir level as exogenous variables

2) Increase the amount of transmission capacity by a small amount; and calculate the resulting price production, consumption and net export changes in both markets keeping other factors constant

3) Using the out of the simulation model, we tried to compare the results (the policy change scenario) without the increment in the of the transmission capacity (base line scenario)

In this manner, we can estimate the value of discrete increments in transmission capacity between south Norway and Western Denmark.

5. Results and Interpretations

In chapter four, the supply and demand curves of both countries have been developed using a structural modeling approach. These are used as input for our simulation analysis. In this chapter, the results of the model estimation and simulation analysis results are presented and interpreted. The main objective of this thesis is to analyze the welfare impacts of the newly upgraded transmission lines in the Nordic region by taking the case of Skagerrak 4; a 700MW trans-national transmission project between NO1 and DK1. The first simulation is thus made for this level of transmission capacity. Moreover, the impact of further upgrades by 1400 MW and 2100 MW on welfare has been analyzed.

Recognizing that the welfare impact of different levels of capacity are affected by changes in the IRLs and the season in the year, each transmission capacity level has been simulated under 60, 70 and 80 percent of IRLs for NO1 and four different years including wet, average and dry years. Here, wet year refers to a total inflow of 102.36TWh in NO1; average year refers to a total inflow of 98.2TWh; and dry refers to a total inflow of 79.66TWh. Each policy option is analyzed with respect to changes in prices, production, consumption, net export and overall welfare.

5.1. Results of model estimates

As our estimated models are the inputs for the simulation analysis, under this subsection we briefly discus the results of our estimated supply and demand models. For both supply and demand, we excluded the hourly dummies for result interpretation purpose (detailed results are reported in Appendix A).

Supply

Table 6 and Table 7 summarize the estimated coefficients along with the HAC standard errors for NO1 and DK1 invers supply function respectively.

Variable Name	Coefficient with HAC st.error
Prod_no1	0.367(0.063)***
Lninflow	-0.03(0.033)
Lnrhsort	2.76(0.265)***
Trend base	0.00(0.00)***
Trigonometric cycle(sine)	-0.004(0.039)
Trigonometric cycle(cosine)	0.135(0.044)***
lnP_oil	0.667(0.180)***
Gov't 5-year bonds(solb5)	-0.180(0.049)***
lnp_co2	0.495(0.079)***
Dummy for co2 market	1.445(0.251)***
Observations 52244	
Significant at 10%; ** significant at 5%; *** significant at 1%	

Table 6: NO1's inverse supply function

As we can see from Table 6, a 1% increase in production leads to a 0,367% increase in price keeping other factors constant. A 1% decrease in reservoir level shortage, keeping other factors constant, leads to 2, 76% increase in price. Increasing oil price by 1% leads to a 0,667% increase in price. A 1% increase in government bond leads to 0, 18% decrease in price holding other factors constant. Dummy for co2 market, as the firm participates in the co2 market, keeping other factors constant, price increases by 1.445 % compared to the price of those who does not participate. As the co2 price increases by 1%, price of electricity will increase by 0.495%.

Variable Name	Coefficient with HAC st. error
lnsup_dk1	0.931(0.069)***
Lnpgas	0.13(0.549)
lnp_coal	0.617(0.594)***
lnp_co2	0.221(0.564)***
Dummy for co2 market	0.256(0.178)*
Trend base	0.000(0.000)***
Trigonometric cycle(sine)	0.128(0.164)***
Trigonometric cycle (cosine)	0.271(0.335)***
Observations 52554	
*Significant at 10%; ** significant at 5%; *** significant at 1%	

Table 7: DK1's inverse supply function

As reported in Table 7, a 1% increase in centralized and decentralized production leads to a 0,931% increase in price keeping other factors constant. A 1% increase in coal price, keeping other factors constant, will lead to 0.617% increase in price. Dummy for co2 market, compared with non-participants, for participates in the co2 market price increase by 0,256 % keeping other factors constant. As the co2 price increases by 1%, price of electricity will increase by 0.495%.

Demand

The estimated coefficients along with the HAC standard errors in parentheses for NO1 and DK1 demand function are reported in Table 8 and Table 9 respectively.

Variable Name	Coefficient with HAC St. error
lnprice_no	-0.037(0.004)***
Lnhd	-0.056(0.002)***
lnhd2	0.045(0.001)***
Daylight in Oslo	-0.034(0.00)***
Lnipi	0.224(0.011)***
Dummy for working days	0.084(0.002)***
Trend base	-0.00(0.00)**
Trigonometric cycle(sine)	0.050(0.002)***
Trigonometric cycle (cosine)	0.143(0.003)***

Observations 52412
*Significant at 10%; ** significant at 5%; *** significant at 1%

Table 8: NO1 demand function

As we can see from the result in Table 8, a 1% increase in price will lead to around 0.04% decrease in consumption of electricity keeping other factors constant. When heating degrees increases by 1 degree celcius, keeping other factors constant, consumption decreases by around 0.06 %. When there is day light in Oslo consumption of electricity drops by 0.034% holding compared with night time other factors constant. As the industrial price index increases by 1 %, consumption also increases by around 0.224 % keeping other factors constant. Compared with other days, consumption during working days is higher by around 0.084 % holding other factors constant.

Variable Name	Coefficient with HAC St. error
lnprice_dk1	-0.014(0.025)*
Hddk	0.016(0.002)***
Lnhdden	-0.022(0.004)***
Ds	-0.093(0.006)***
Dummy for holidays	-0.003(0.008)
Dummy for working days	0.23(0.007)***
Trend base	-0.00(0.00)*
Trigonometric cycle(sine)	0.003(0.004)
Trigonometric cycle (cosine)	0.054(0.007)***
Observations 52584	
*Significant at 10%; ** significant at 5%; *** significant at 1%	

Table 9: DK1 demand function

As we can see from the result in Table 9, a 1% increase in price will lead to around 0.014% decrease in consumption of electricity keeping other factors constant. When heating degrees increases by 1 degree Celsius, keeping other factors constant, consumption will decrease by around 0.02%. Compared with the other weeks, consumption of week28, 29 and 30, decrease by around 0, 093 % keeping other factors constant. Compared to consumption in other days, electricity consumption for working days increases by 0.23%, and holiday consumption decreases by 0.003%; holding other factors constant.

5.2. Impact of planned transmission capacity expansion

This section analysis the economic and welfare impact of increasing the transmission capacity by 700MW. We discuss the results on overall average changes as well as hourly average changes for production, consumption, prices and net export. In the case of congestion rent we took the actual base case and policy change values.

5.1.1. Production and consumption

From literatures we know that driven by initial price difference (base line scenario), producers change their supply as the transmission capacity changes. As we increase the capacity suppliers tend to compete over the larger market. On the other hand electricity demand is known to be inelastic, does not change as such to price changes .Below we discuss how supply and demand changes when we upgrade the transmission capacity.

A change in transmission capacity affects the behavior of generators and demand. An increase in transmission capacity tends to intensify the competition for larger market in which very expensive generators (e.g. thermal generators in DK) have to cut their generation while less expensive generators (e.g. hydro in NO) have to increase their generation. This implies a change in the total producer surplus even though some generators lose and others win.

Unlike the supply side, the demand side is not very sensitive to price changes. That is, with the increase in capacity, the consumption of the both Norwegian and Danish consumers does not change significantly. However, it creates a change/ shift in consumer surplus. The consumers of importing country pay less while those on the exporting side pay higher prices leading to increase and decrease in consumer surplus, respectively.

In what follows, the overall average and hourly changes are analyzed for the planned level of transmission expansion.

Supply

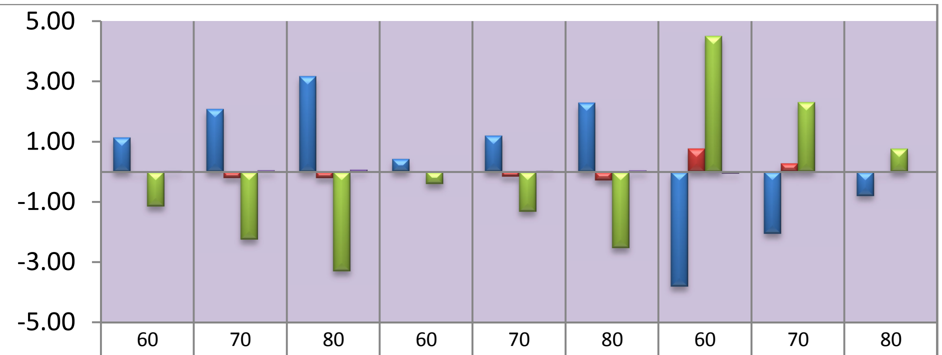
Average change

In wet and an average year, NO1 has more water; the value of water is very low. Thus electricity production from hydro is cheap. On the other hand for these years, DK1 marginal cost of thermal production is higher than the social price. Consequently, even under the base case, NO1 produces more and DK1 produces less because they have to cut their generation since they cannot compete with the cheap import. However these changes are constrained by the available transmission capacity.NO1 is even forced to spill over the water for wet year with high IRL[9].Furthermore, DK1 is not able to use only

[9] As reported in the appendix, there is over flow of energy under the base case scenario.

cost efficient thermal plants as expensive plants have to produce when the transmission line is congested. As we increase the transmission capacity, NO1 produces more and sell abroad pushing up the water value. DK1 decreases its costly production, which pushes down the marginal cost. As can be seen from Figure 7, for example, NO1's production on average increases by 3% and 2% compared to the base case scenario and DK1's supply on average decreases by 16% and 12% under wet and average year respectively with 80% IRL.

On the contrary, for a dry year, NO1 has less inflow hence water is overvalued especially during dry year with low IRL. Here cost of hydro production is high. Comparing water value with marginal thermal cost, more thermal will be used when water value is high (Forsund, 2007). Consistent with this argument, in dry year, DK1 increases its thermal production. Accordingly, adding additional transmission capacity means allowing NO1 to import relatively cheaper electricity from DK1 and save the water. For DK1, it becomes profitable to increase their thermal supply to meet the domestic demand as well as export. For example, when IRL is 60% NO1's supply decreases by 5% and DK1's supply increases by 15%. However, as can be seen from Figure 7, the decrease in NO1's supply and an increase in that of DK1 are on average smaller when there is high initial reservoir in NO1. As NO1 has more water at the beginning of the year, water value is low hence production is high at the beginning of the year.



	Wet year			Average year			Dry year		
	60	70	80	60	70	80	60	70	80
NO1 production (TWh)	1.13	2.09	3.17	0.42	1.19	2.29	-3.79	-2.06	-0.80
NO1 consumption (TWh)	-0.04	-0.21	-0.21	0.01	-0.16	-0.28	0.77	0.28	-0.02
DK1 production (TWh)	-1.14	-2.24	-3.30	-0.40	-1.32	-2.52	4.51	2.30	0.76
DK1 consumption (TWh)	0.03	0.05	0.08	0.01	0.03	0.05	-0.05	-0.03	-0.01

Figure 7: Production and consumption of both countries

Over all, wet year with 80% IRL and dry year with 60% are the most crucial times for transmission expansion .under Base cases of these scenarios more players want to use the line and the lines become saturated and these are the times we find huge changes in both countries production as the result of transmission expansion. In a wet year, hydro power production is cheap thus as increasing the transmission capacity, supply of NO1 increases. That is, with the increased capacity, generators prefer to compete over both markets. This fosters competition and as a result DK1 decreases its supply from thermal generators. For Dry year shadow price of water is high and cost of electricity production in NO1 is high compared to that of DK1.

Hourly change

Figure 8 and Figure 9 summarize the average hourly changes in the supply of both countries for wet year and dry year. Where supply_nob and supply_dkb represent base case supply and supply_noc and supply_dkc represent policy change supply of NO1 and DK1 respectively.

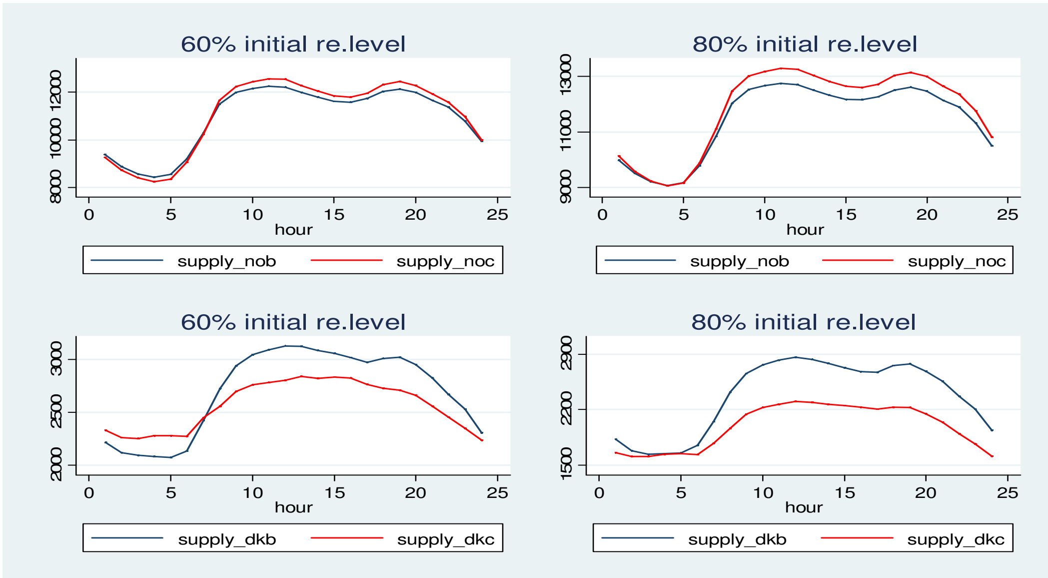


Figure 8: The average hourly changes in the wet year

As we can see from Figure 8(left), when the IRL is 60%, NO1 increases its supply on average between 7AM and mid-night including peak hours while DK1 decreases its supply for these hours. For those hours between mid-night and 7AM, NO1 decreases its supply while DK1 increases. Here NO1 starts the year with low water in the reservoir; hence at least at the beginning of the year water value is high. Thus NO1 uses the increased transmission capacity to shift more water previously used to production of peak and shoulder load when price is relatively high. Whereas DK1 uses the additional transmission capacity to produce more during off peak hours by using the cost efficient power plants.

When the IRL is 80% Figure 8(right), on average NO1 supply increases and that of DK1 decreases for all hours except around 4AM -6AM. In this year NO1 has more inflow which exceeds its reservoir capacity. With the increase in capacity, NO1 can increase its supply and export more as the only alternative to spilling water. DK1 has an opportunity to increase its import of NO1's surplus hydro hence it decreases its thermal supply. However, we see from Figure 8 (right), supplies of both countries remain the same around 4AM-6AM after transmission line expansion. This indicates that for these hours the line was not congested before.

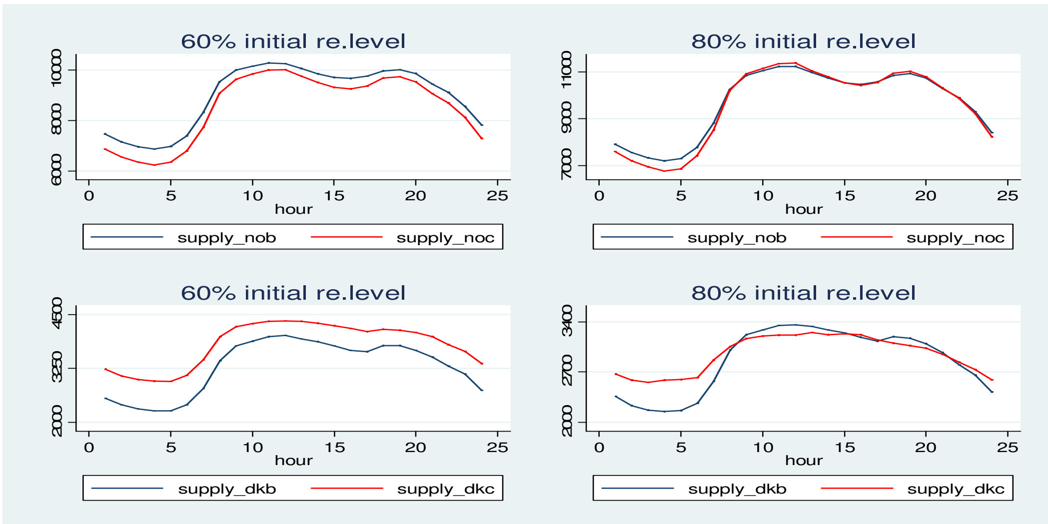


Figure 9: Average hourly production in dry year

For a dry year with 60% IRL in NO1, water value is extremely high .NO1's supply decreases on average for each hour of a given day while that of DK1's increases as the result of increasing the transmission capacity. As we can see from Figure 9 (left), in dry year, thermal production has also increased its peak load supply.

At an IRL of 80%, NO1's supply increases on average during peak load hours and decreases during off peak load hours, while DK1's supply increases during off peak hours and decrease during peak hours as the result o the transmission expansion. Under this case NO1 starts the year with high water in the reservoir. However during the year inflow is low. Thus, as we increase the transmission capacity, NO1 saves more water in the reservoir for peak load hours and increases its supply when prices are high compared to the base case scenario. On the other hand, DK1 increases its supply for the base load and depend more on the NO1's supply for peak hours when it has high marginal cost.

In sum, these findings indicate that increasing the transmission capacity helps the two countries exploit the complementariness of their power generation sources depending on the water value and the marginal cost of thermal production. It also leads to a more competitive outcome by enhancing the opportunity for less expensive generators to supply the load, NO1 in the case of wet and an average year and DK1 in the case of dry year. The results we have found are in line with the arguments forwarded by multiple authors, for example, (Borenstein and Bushnell, 2000, Joskow and Tirole, 2000, Leautier, 2001) , regarding the impact of transmission capacity.

Demand

Average change

As we can see from Figure 7, the increase of DK1's demand and the decrease of NO1's demand are insignificant. In our case demand is not responding the price changes that arise from trade as we increase the transmission capacity. Electricity demand is price-inelastic.

Hourly change

The following figures depict the average hourly demand. Where demand_nob and demand_dkb represent the base case demand and demand_noc and demand_dkc represent the policy change demand for NO1 and DK1 respectively.

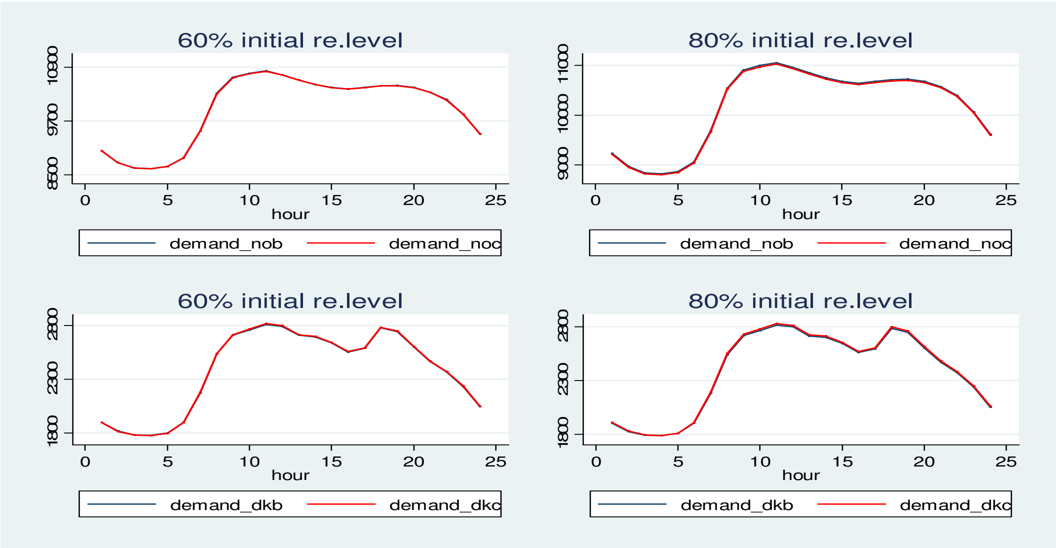


Figure 10: Average hourly consumption for wet year

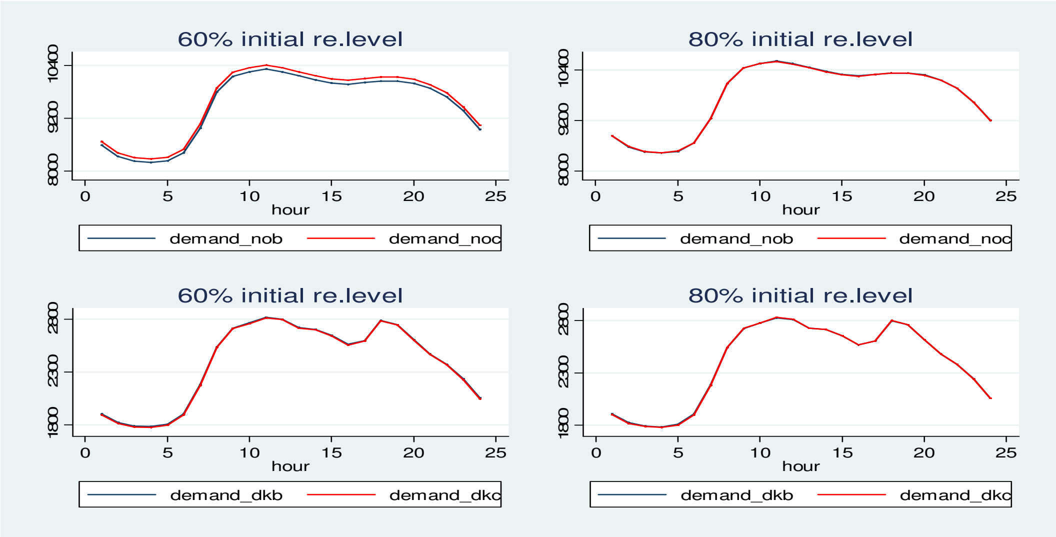


Figure 11: Average hourly consumption for dry year

As we can see from Figure 10 and Figure11, Consumption does not show significant change as we increase the transmission capacity. The only noticeable change is for NO1 consumption under dry year with low level of IRL. This is because electricity price is extremely high in NO1 for this period under the base case scenario. Hence, as we upgrade the transmission capacity, relatively cheaper and affordable electricity become available and consumers reacted my slightly increasing their demand.

5.1.2. Net export

Increase in transmission capacity increases the volume of power transacted between countries/zones as more power flow from low cost generation area to high cost generation area. In our case, the flow of electricity is affected by the season we are dealing whether its dry or wet with as well as the particular hour whether its peak or off peak hour. In what follows, the impact additional 700 MW capacity on the average annual and hourly changes in net export are analyzed.

Average change

The average annual change in net export is depicted in Figure 12, in which positive values show flow from NO1 to DK1 while negative values show flows from DK1 to NO1.

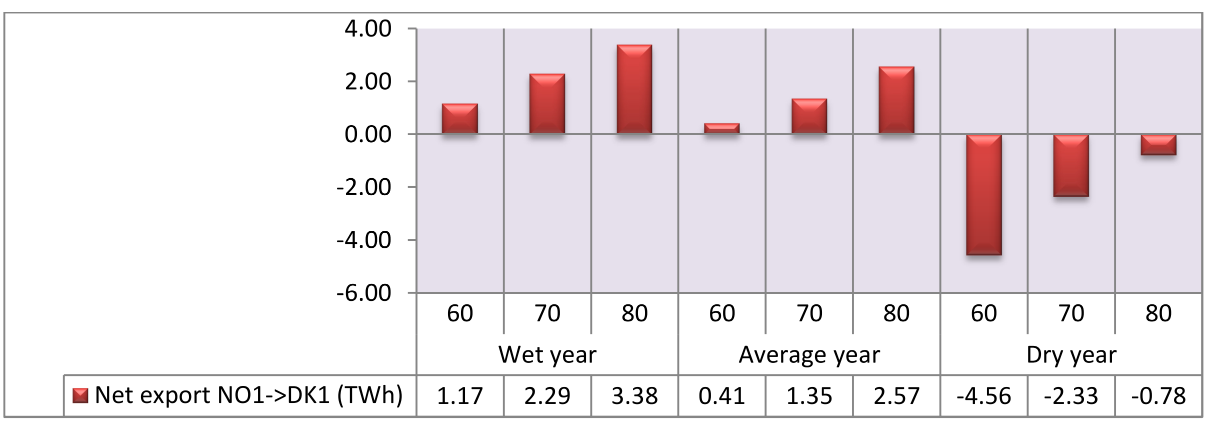


Figure 12: Average changes of net export

In the wet and average year, net export of NO1 (NO1 to DK1) increases as production of NO1 increases during these years. The change is magnified with the higher level of IRL (when the water value is the lowest). In wet year with 80% IRL, the net export increases on average by 3.38TWh, which is around 70%, compared with base case scenario. In the dry year, the net power flows from DK1 to NO1 increase. In this case, the highest increment in DK1's net export is 4.56TWh which is around 103%, when NO1 sets its IRL to 60%IRL. In dry year with 60% IRL, peak load thermal plants are also in operation. The volume of export decreases as the IRL of NO1 increases since the initial amount of water in the reservoir is high for NO1. However compare with the base case scenarios still NO1 imports more as we increase the transmission capacity.

Hourly change in net export

The average hourly changes in net export are shown in Figure 13 where ex_no_dkb and exp_no_dkc represent the base case and the policy change net export respectively.

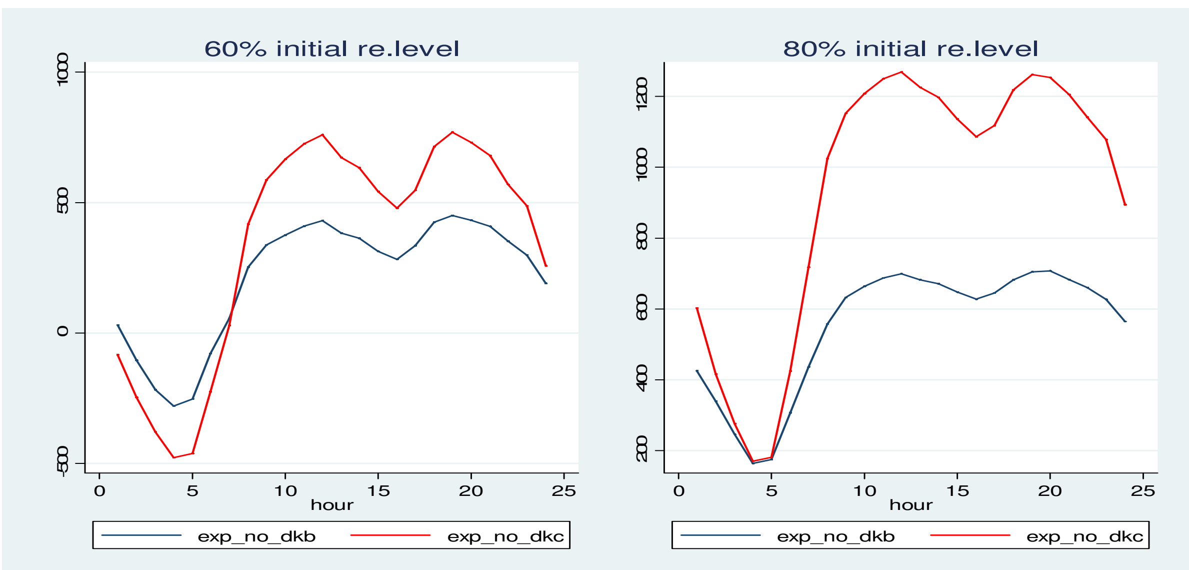


Figure 13: Average hourly changes of net export for wet year

In wet year and setting the IRL to 60%,Figure 13(left), increasing the transmission capacity gives NO1 an opportunity to transfer more water, which otherwise would have been used and export more during peak and shoulder load hours between 7AM and mid-night . On the other hand, DK1 takes advantage of the transmission capacity increment by increasing its base load supply and export between mid-night and 7AM and depend more on import from NO1 for peak load hours.

Increasing IRL to 80% increases the net export from NO1 for all hours except around 3AM-5AM[10]. As we can see from Figure 13 (right), for peak and shoulder load hours, the transmission line was extremely congested since cheaper water was locked in NO1. Increasing the transmission capacity, net export on average increases massively. For those off peak hours between 3AM-5AM net export is not affected by transmission capacity upgrade.

Figure 14 displays the change in net export during dry year assuming 60% (left) and 80% (right) IRLs.

Figure 14: Average hourly changes of net export for dry year

In dry years, the water value is high and increasing the transmission capacity increases flow of relatively cheaper power from DK1.As we can see from Figure 14(left), a relatively low IRL leads to a significant increase in the net export of DK1. NO1 is a net

[10] On average even for the base case scenario NO1 is net exporter during wet year with 80% IRL. During this period NO1 is using the water that otherwise would have been spilled over.DK1 is imports more of the cheap surplus hydro power.

importer even under the base case scenario and as we increase the capacity, import increases tremendously. Thus the line was extremely congested during this period under the base case. However if we see the peak load hours, NO1's import is not as huge as it is for base load hours. However, if the year starts with high IRL (80%) Figure 14(right), NO1 has more water at the beginning of the year. Under the base case scenario, NO1 on average exports during peak load hours, DK1 exports during off peak load hours and net export is almost zero for shoulder load hours. As we increase the transmission capacity, NO1 saves more water for peak load hour production and hence increase its export and depends on import from DK1 for off peak and shoulder load hours.

5.1.3. Change in electricity prices

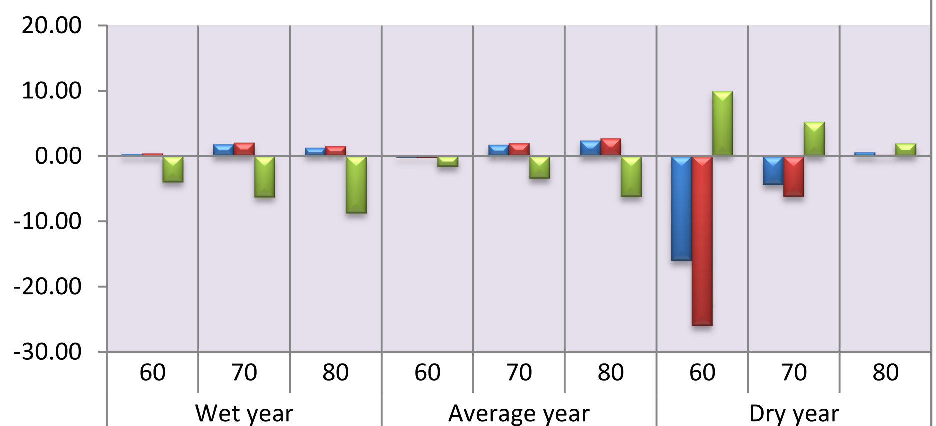
Transmission line bottlenecks lead to a difference in prices as it limits the flow of electricity from less expensive to more expensive markets. Increasing transmission capacity thus reduces the price difference. However, this would mean increasing the price in exporting country while decreasing the prices in the importing country.

Average change

The changes in the prices follow the changes we saw above for net export. In the wet and average years, increasing the transmission capacity increases the system price and that of NO1 while decreasing the prices in DK1. However, in the dry year the system price and NO1 price decrease whereas DK1 price increases. The reason is in wet and an average year NO1 exports more hence uses more water which pushes it value up and this is reflected through its price. On the other hand, DK1 is importing more cheap hydro power so price goes down. In the dry year as water value is high; NO1 price is high under the base case. As we increase the transmission capacity, relatively cheaper electricity is flowing towards NO1. This decreases NO1 price and increases that of DK1's. From Figure 15, we can see that the highest price change for NO1 is a decrease by 26 EUR/MWh (24% compared with the base case) which is for dry year with low level of

IRL (60%). For the same scenario, DK1's price increase on average by 9.95EUR/MWh (by 18% compared with the base case).

The highest DK1's price decrease which is on average by 8.76 EUR/MWh (by 23% compared with the base case) is for wet year and 80% IRL. In this year NO1's price increases on average by 1.51EUR/MWh (by 7% compared with the base case). Thus increasing the capacity changes these countries prices because of its competitive effect on electricity suppliers and hence electricity flows between the countries.



	Wet year 60	Wet year 70	Wet year 80	Average year 60	Average year 70	Average year 80	Dry year 60	Dry year 70	Dry year 80
SYS price (EUR/MWh)	0.31	1.77	1.23	-0.23	1.72	2.38	-15.99	-4.32	0.61
NO1 price (EUR/MWh)	0.40	2.05	1.52	-0.27	1.96	2.71	-25.95	-6.14	0.22
DK1 price (EUR/MWh)	-4.02	-6.32	-8.76	-1.60	-3.40	-6.18	9.95	5.22	1.93

Figure 15: Changes in average system, NO1 and DK1 prices

However, as we can see from Figure 15, for a dry year with 80% IRL, on average NO1's price increase. This is because NO1 starts the year with more water in the reservoir so at least at the beginning of the year supply as well as export is high on average. This pushes up the price.

Hourly change

In this section the changes in system prices and the changes in the area prices are analyzed. The price changes flow the direction of changes in export we discussed above.

System price

As we are dealing with a dynamic model, the system price changes as the result of changes we see on the reservoir content.

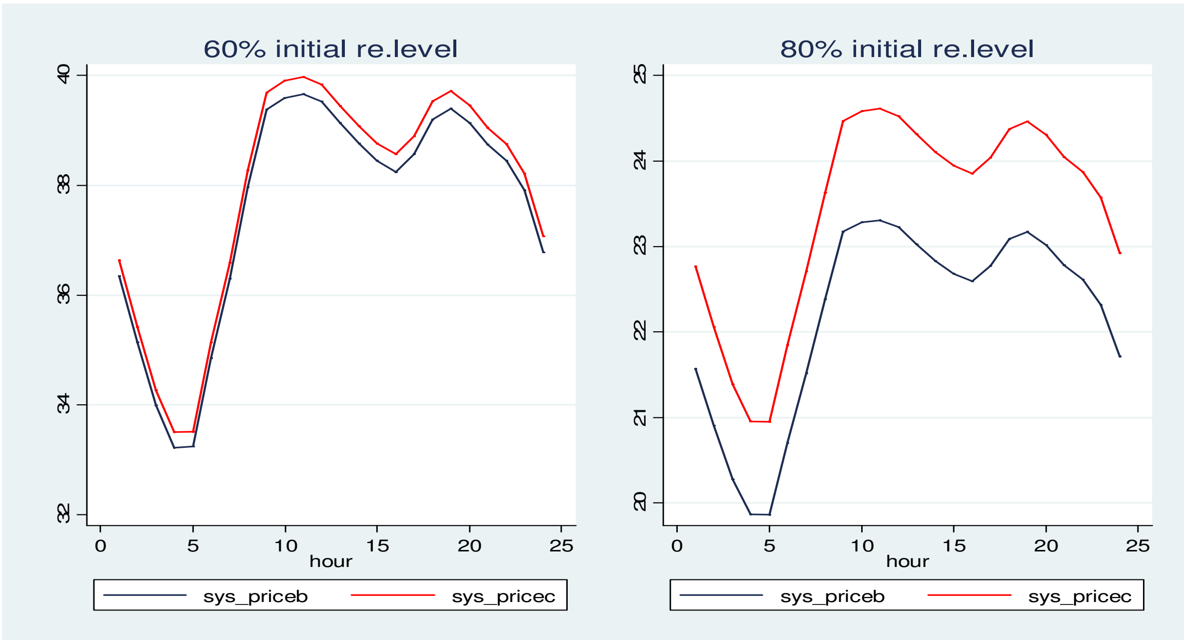


Figure 16: Average hourly system price for wet year

As can be seen from Figure 16, in the wet year system price increases with an increase in transmission capacity as this increases the power transmitted from NO1 to DK1. That is, the price that clears both markets' is pushed up. It can also be noticed that this change depends on the IRL of NO1 in which an increase in reservoir level magnifies the change.

Figure 17 depicts the change in system price for dry year with a 60% (right) and 80% (left) IRL. With 60% initial reservoir, the system price decreases as thermal generators inject more power changing the direction of flows from DK1 to NO1. However, when NO1 starts the year with high IRL (80%), system price increases. As NO1 supply and export increase so does the water value. This in turn affects the system price.

In both scenarios, the gap between the base case system price (sys_priceb) and the policy change system price (sys_pricec) widens at peak load hours. However, the change is huge for wet year with 80% IRL and dry year with 60% IRL.

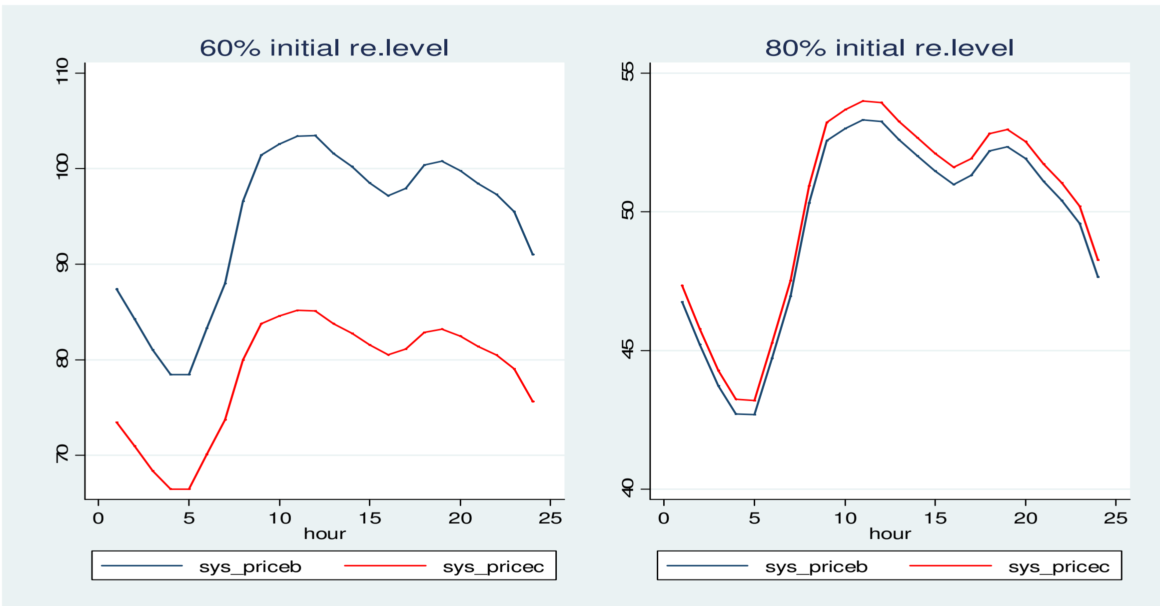


Figure 17: Average hourly system price for year

Prices of NO1 and DK1

Figure 18 shows the changes in area prices of the NO1 and DK1 due to an increase in the transmission capacity by 700 MW during a wet year in NO1.where price_no1b and price_dk1b represent base case prices and price_no1c and price_dk1c represent policy change prices of NO1 and DK1 respectively.

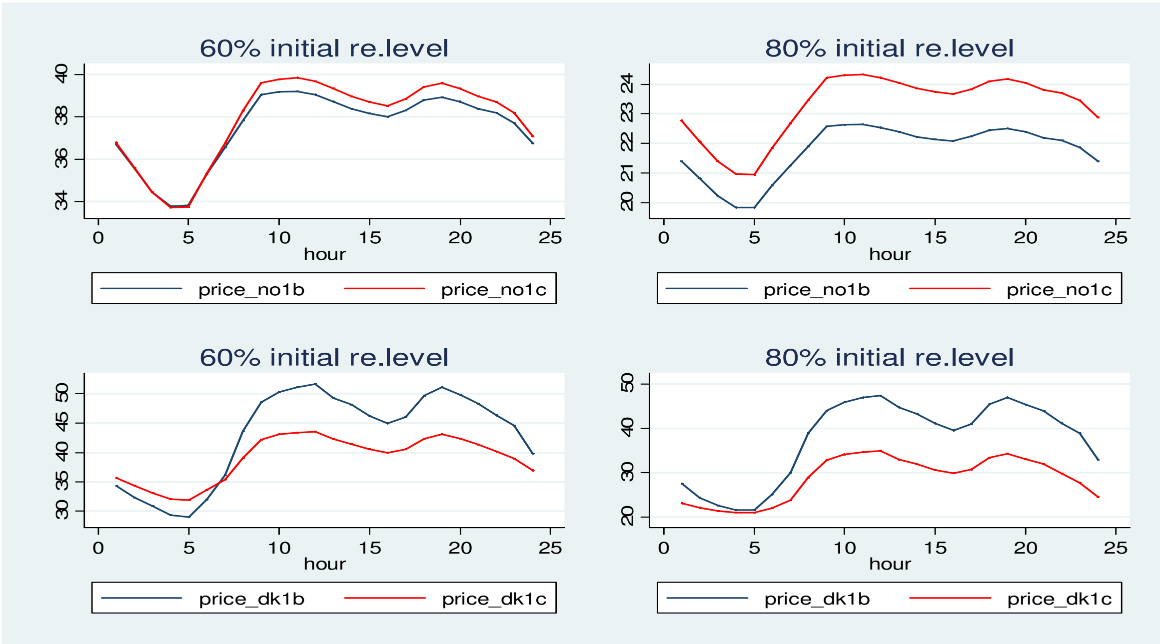


Figure 18: Average hourly NO1 and DK1 prices for wet year

Figure 18(left) shows that when the IRL is 60%, NO1 price increases during peak hours and it decreases during the off-peak hours between 4AM & 5AM. We can also notice that there is no change between1AM & 3AM and between 6AM & 7AM. For DK1, there is an average decrease in the electricity price for each hour except during the off-peak hours, from 1AM till 7AM. As this is a wet year in NO1 with low IRL, export increase for peak and shoulder load hours hence we see on average an increase in price for these hours. For off peak load hours, DK1's price increases as it is exporting more.

With an IRL of 80% Figure 18 (right), on average, NO1 price increases for all hours and that of DK1 decreases for all hours except around 4AM & 5AM. In this case, NO1 increases its electricity production and also its export as we increase the transmission capacity. This increase in export of NO1 increases its price. For the case of DK1, more cheap hydro power is available as the transmission line is upgraded. Thus electricity price decreases.

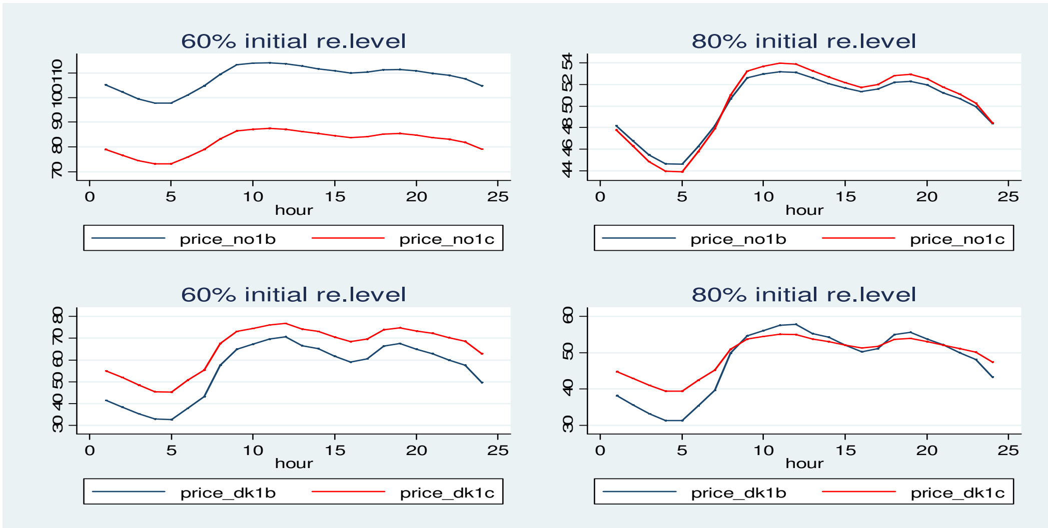


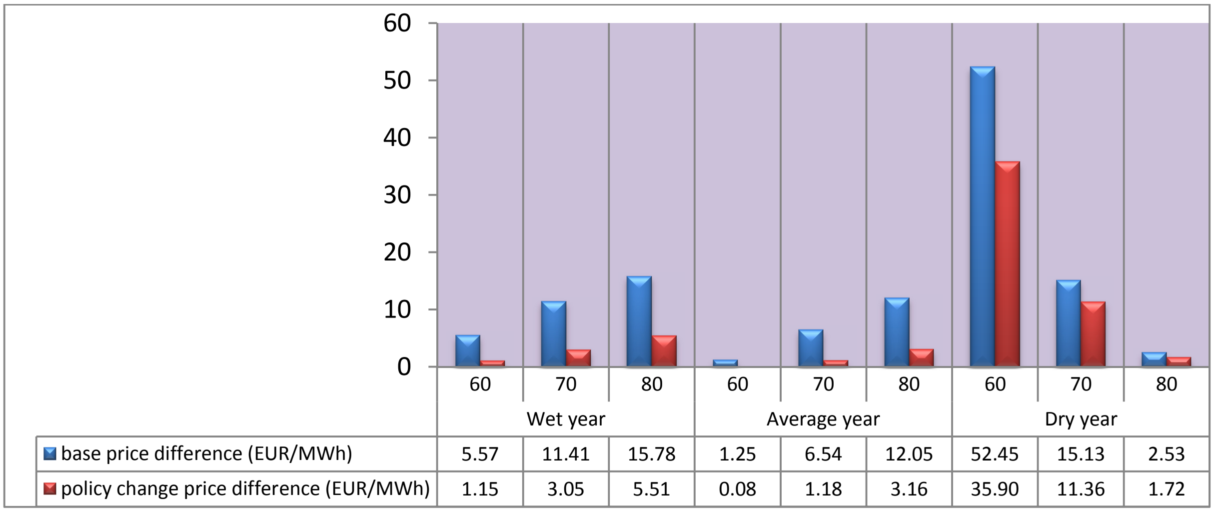
Figure 19: Average hourly NO1 and DK1 prices for dry year

Even if it is a dry year in NO1, the impact of increasing the transmission capacity varies as the IRL varies. As can be seen from Figure 19(left), when the IRL is 60%, the NO1 price decreases on average for each hours of the day while that of DK1 increases. With an IRL of 80%, NO1 has high water at the beginning of the year and is able to meet peak hour demand. Accordingly, Figure 19(right) shows that as we increase the transmission capacity, NO1 price increases on average for peak and shoulder load hours and decreases on average for off peak hours between mid-night & 7AM. DK1 price on average increases for off peak hours between mid-night & 7AM and decreases on average for peak and shoulder load hours.

The price changes show the change in water value for NO1 and marginal cost of production for that of DK1.

Price difference

Increasing the transmission capacity, narrows the price difference between trading countries by increasing the exporting country's price and decreasing that of importing country. Figure 19 shows the price difference as the result of upgrading the transmission capacity[11].



	60	70	80	60	70	80	60	70	80
	Wet year			Average year			Dry year		
base price difference (EUR/MWh)	5.57	11.41	15.78	1.25	6.54	12.05	52.45	15.13	2.53
policy change price difference (EUR/MWh)	1.15	3.05	5.51	0.08	1.18	3.16	35.90	11.36	1.72

Figure 20: Price differences between NO1 and DK1

As can be seen from Figure 20, the price differences decrease with an increase in transmission capacity. During the dry year with 60% IRL, the price difference is around 52M€ however, increasing the capacity narrows this difference to around 17 M€ which is 68% decrease compared with the base case scenario. For wet year with 60% IRL, we see a 99% decrease in the two countries price differences. Hence we can say increasing the transmission capacity price convergence.

Price volatility

We used distribution of the prices in order to see whether or not increasing the transmission capacity decreases price volatility. We calculated the distance of the lower 5% and the upper 95% from the median price for base case as well as the policy change scenario to see if the gap increases or decreases.

[11] To show the price difference we used the base line difference and the policy change difference. Not the change as we did for other key variables

	Wet year				Dry year			
	IRL = 60 %		IRL = 80 %		IRL= 60 %		IRL = 80 %	
	5% from 50%	95% from 50%	5% from 50%	95% from 50%	5% from 50%	95% from 50%	5% from 50%	95% from 50%
price_nob	64 %	129 %	64 %	182 %	61 %	185 %	71 %	157 %
price_noc	67 %	139 %	66 %	188 %	56 %	146 %	71 %	155 %
price_dkb	56 %	166 %	42 %	198 %	43 %	167 %	51 %	160 %
price_dkc	65 %	142 %	57 %	210 %	53 %	141 %	70 %	157 %

Table 10: Price distribution

For NO1

In wet year, the lower 5% price distribution is lower than the median price by 3% and 2% for 60% and 80% IRL respectively. This implies that there is no significant distribution change. For 95% price distribution, the gap from the median price widens to around 10% and 6% for 60% and 80% IRL respectively as compared to base case scenario. Therefore, increasing the transmission capacity increases the NO1's price volatility for the upper 95%. So we still have price spikes.

In dry year, the gap between the lower 5% price distribution and the median price decreases by 5% and for 60% IRL and the gap remains the same for 80% IRL. In the upper 95%, the gap form the median price decreases by 39% and 2% for 60% and 80% IRL, respectively. For a dry year, increasing the transmission capacity helps to stabilize NO1's electricity market by decreasing price volatility.

For DK1

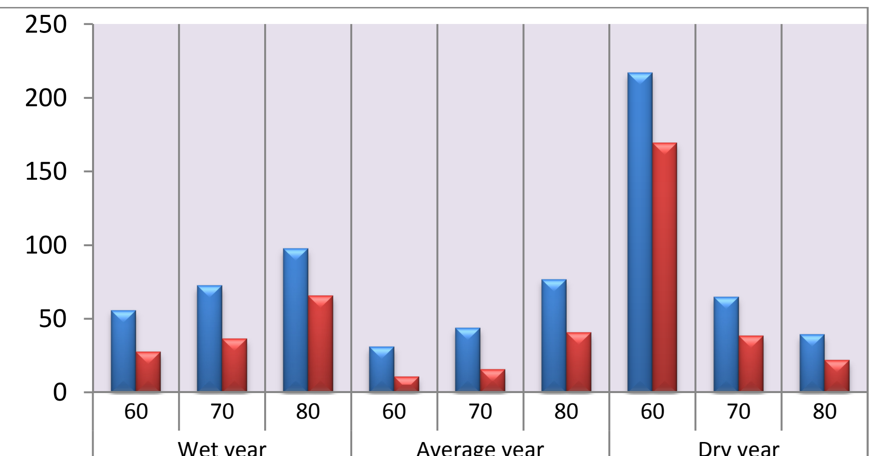
In wet year, the gap between the lower 5% price distribution and the median price increases by 9% and 15% for 60% and 80% IRL, respectively. The gap from the median price increases by 12%. However, it decreases by 24% when NO1 starts the year with 60% IRL. Thus in a wet year with high IRL, though DK1 imports more, the price is still volatile and we still have high prices.

Increasing the transmission capacity in the dry year, the lower 5 % price distribution is further lower than the median price by 10% and 19% for 60% and 80%, respectively. For above 95% distribution, the gap from the median price decreases by 26% and 3% for 60% and 80% IRL, respectively. In the case of dry year, increasing the transmission capacity decreased price volatility above the median price.

The reason we still have price volatility and price spikes is because, as explained by Shahidehpour.M (2002), in addition to transmission line bottlenecks, volatility in fuel price, load uncertainty, fluctuations in the hydroelectricity production, generation uncertainty (outages) and behavior of market participants also contribute to electricity price volatility.

5.1.4. Congestion rent

Congestion rent is revenue that TSOs collect when the transmission capacity is congested. It depends on the price difference between transacting markets and the power flows on the line connecting the markets. Congestion rent gives economic signal and incentive for transmission expansion. As we increase the transmission capacity, prices converge to the marginal costs of generators and congestion rent decreases (Rosellón et al., 2011, Wu et al., 2006).



	Wet year 60	Wet year 70	Wet year 80	Average year 60	Average year 70	Average year 80	Dry year 60	Dry year 70	Dry year 80
base congestion rent (mill EUR)	55.76	72.66	97.66	31.14	43.91	76.6	217.08	64.89	39.45
policy ch. Congestion rent (mill EUR)	27.81	36.78	65.81	10.95	15.90	40.95	169.49	38.61	22.22

Figure 21: Congestion rent

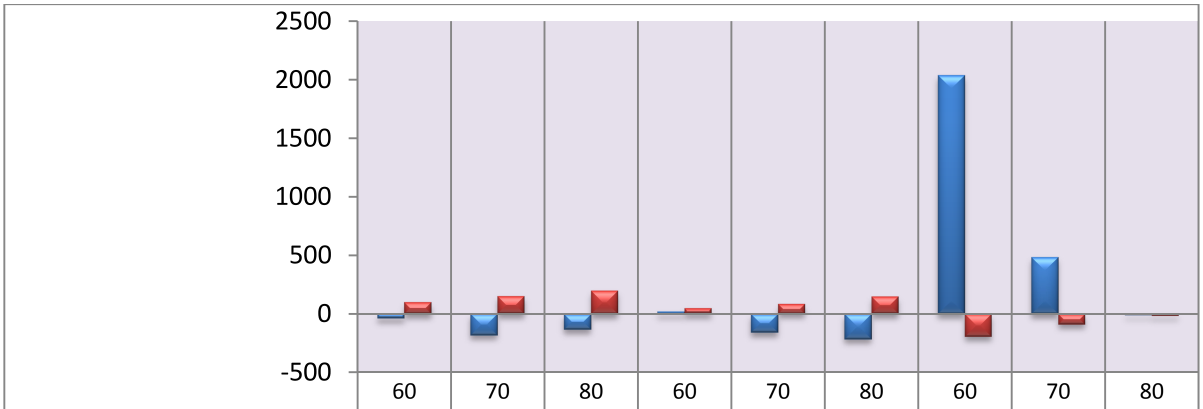
Figure 21 compares the€ level of congestion rent for the base case scenario and the scenario with upgraded transmission capacity. In wet year, the maximum decrease in congestion rent which is by 49% occurs if we have an IRL of 70%. In average year, the maximum decrease which is by 47% is reported if the IRL is set at 80%. The highest congestion rent occurs in dry year with 60% IRL which is around 217 M€ in the base case which further decreases to 169.5 M€ with an upgrade in transmission capacity. This is a reduction by 29%. As can be seen, congestion rent has decreased substantially under all scenarios. The reason for the reduction in congestion rent in all cases is because the capacity upgrade narrows the price differences between NO1 and DK1 which is partly offset by the increase in the volume of power traded.

5.1.5. Welfare analysis

The core value of a policy change depends on the extent it contributes in enhancing net welfare. In addition, losers and winners of the policy should be identified to draw implications based on the policy. In what follows, the changes in consumer and producer surplus as well as the net welfare change are discussed.

5.1.5.1.Consumer's surplus

Increasing transmission capacity increases the price of exporting country and decreases the price of importing country. The implication is that, the consumer living in the country with high-variable cost capacity enjoy a price fall at the expense of consumers living in the country of low-cost capacity (Finon and Romano, 2009, Hogan, 2010). Figure 22 depicts the average annual changes in consumer surplus in NO1 and DK1. It can be noticed that the consumer surplus in NO1 has decreased as we increase the transmission capacity in wet and average year. This is because of the price changes we discussed in section 5.1.2. On the contrary, the surplus of DK1's consumer increases under these years as the increase in transmission capacity enables them import cheaper electricity from NO1. In wet year with 80% IRL, the highest consumer surplus change for DK1 consumers is around 196 M€ (24%) compared to the base case.



	Wet year 60	Wet year 70	Wet year 80	Average year 60	Average year 70	Average year 80	Dry year 60	Dry year 70	Dry year 80
Change CS in NO1 (mill EUR)	-38.30	-182.93	-132.14	17.36	-158.59	-215.28	2035.70	483.12	-14.44
Change CS in DK1 (mill EUR)	96.95	146.92	196.38	45.08	85.52	145.66	-195.99	-89.46	-19.86

Figure 22: Average changes in consumer surplus

However, in dry year, the direction of electricity flow is from DK1 to NO1, hence consumers in NO1 are better off while consumers in DK1 become worse off. In a dry year with 60% IRL, the highest additional consumer surplus for NO1 is around 2,036 M€ (22%) compared with the base case. This value changes as we increase the IRL leading to a decrease in the consumer surplus of both countries at 80% IRL.

5.1.5.2.Producer's surplus

When transmission capacity is upgraded, driven by the base case price differences, producers change their supply. This in turn affects the revenue they receive and the cost they incur and hence their producer surplus (Hogan, 2010). Figure 23 shows the average changes of producer's surplus of NO1's hydro power generator.

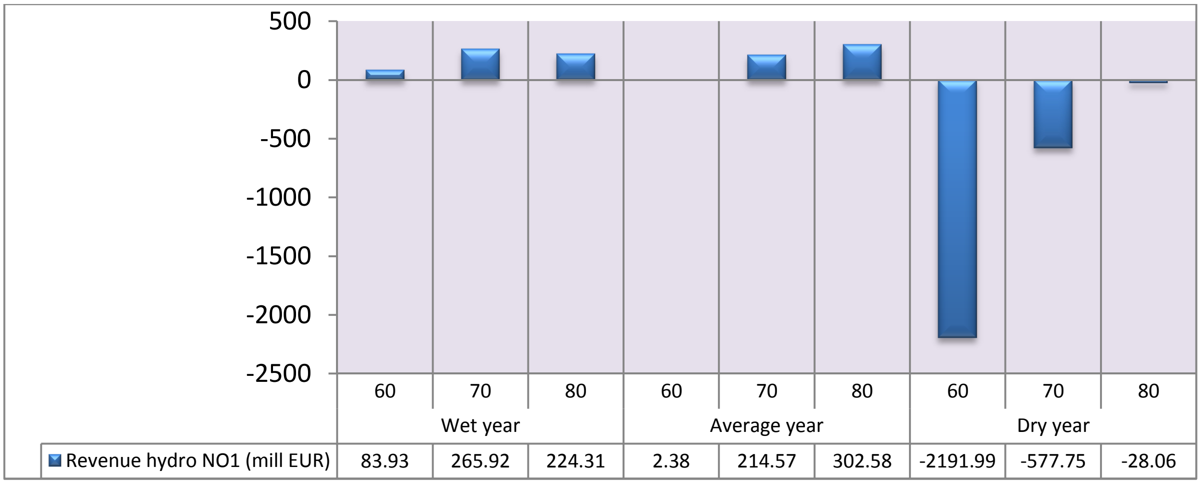
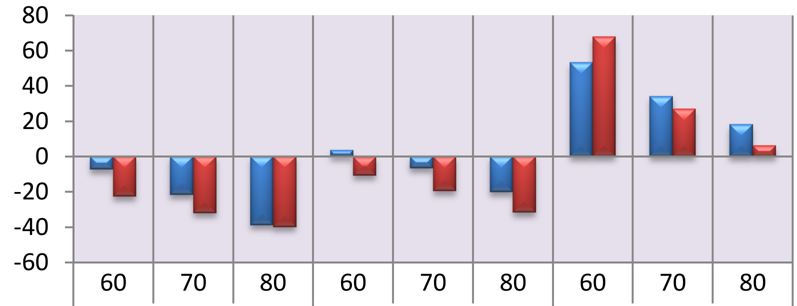


Figure 23: Average changes in hydro revenue of NO1

In the wet and average years, the change in producer's surplus of NO1 is positive in which the change gets highest for an average year with 80% IRL. Which is an increase of around 303M€ (13%) compared with the base case. In dry year, the change in hydro revenue is negative and the change is high when we have 60% IRL. This on average is a decrease of around 2,192 M€ (26%) compared with the base case. This decrease in hydro power revenue decreases when IRL increases.

The changes in the surplus of thermal and wind power plants of DK1 are shown in Figure 24. It can be noticed that in wet and average years, wind revenue and producers surplus of thermal has decreased on average. The highest decrease occurs when the year is wet and there is 80% IRL. Which are an average decrease of 39 M€ and 40 M€ (20% and 40%) compared with the base case for wind revenue and producers surplus of thermal respectively.

In the dry years, the thermal and wind power generators gain additional surplus. . The level of surplus they get depends on the IRL. That is as the IRL increases, their surplus shrinks. For instance, under 60% IRL, wind revenue and producer surplus of thermal increase on average by around 53 M€ (22%) and 68 M€ (33%) respectively compared with the base case scenario.



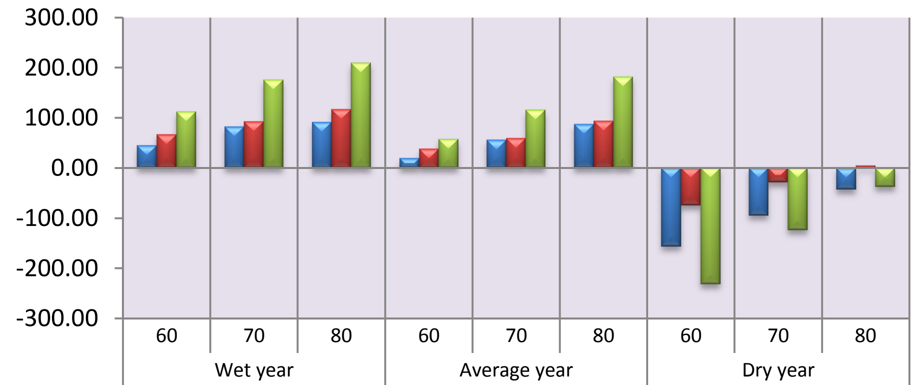
	60	70	80	60	70	80	60	70	80
	Wet year			Average year			Dry year		
Revenue wind DK1 (mill EUR)	-7.36	-21.75	-38.84	3.72	-6.71	-20.14	53.37	34.04	18.25
PS thermal DK1 (mill EUR)	-22.62	-32.10	-39.93	-10.72	-19.44	-31.50	67.88	27.04	6.40

Figure 24: Average changes of DK1's wind revenue and producer's surplus of thermal

5.1.5.3.Overall welfare change

Figure 25 shows the changes in the overall welfare of the each zone and both zones. In wet and average years, the welfare is positive varying with the level of IRL. The positive values imply that the in NO1 the producer's surplus outweighs consumers loss and the consumers gain outweighs producers loss for that of DK1.

However, in dry year, we can see a decrease in welfare in both zones implying that the producers' loss in NO1 outweighs consumer's gains and in DK1 consumers' loss outweighs producers gain. Except when IRL is 80%, for which DK1's welfare improves. Here DK1's producers gain more than offsets the consumers' loss.



	Wet year 60	Wet year 70	Wet year 80	Average year 60	Average year 70	Average year 80	Dry year 60	Dry year 70	Dry year 80
NO1 welfare change (mill EUR)	45.63	82.99	92.17	19.75	55.98	87.31	-156.30	-94.63	-42.50
DK1 welfare change (mill EUR)	66.98	93.07	117.60	38.07	59.37	94.02	-74.74	-28.38	4.78
Net welfare change (mill EUR)	112.61	176.06	209.78	57.82	115.35	181.33	-231.04	-123.01	-37.72

Figure 25: Overall welfare changes

In wet year with 80% IRL, increasing the transmission capacity leads to the highest net welfare improvement amounting to around 210 M€. Therefore, the upgrade increases net welfare as well as the welfare of both countries if we have wet or an average year. However, in dry years, net welfare decreases as we increase the transmission capacity. For example, when IRL is 60%, net welfare decreases on average by around 231 M€.

5.2 Impact of further expansion

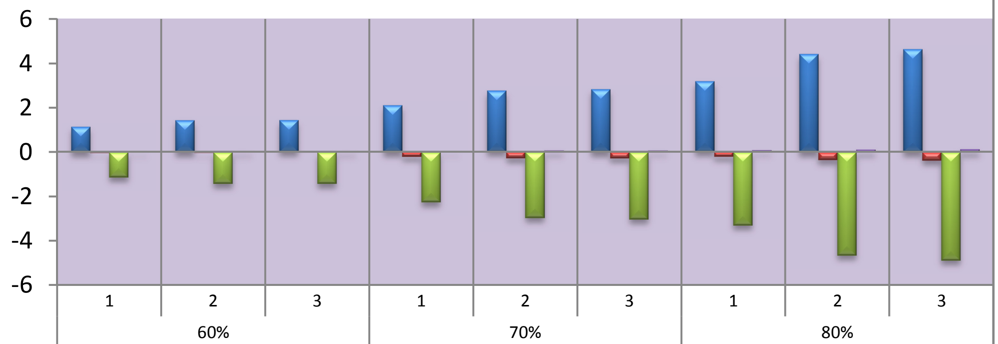
On the previous sub section we discussed impacts of the new transmission expansion between NO1 and DK1. The fact that there are changes in overall net welfare raises questions. Can we further improve social welfare by increasing the transmission capacity? What about the case of dry year, will we worsen the loss of net social welfare?

Under this sub section, we see if we have still room for improving the transmission capacity by increasing the transmission capacity further by 1400MW and 2100MW. To give a simplified interpretation on this sup section we will only be discussing about the average impacts of further increasing the transmission capacity on prices, production & consumption, net export, congestion rent and welfare. The other results can be referred from appendix B.

To make the comparison easier and be able to answer the above question we labeled the policy changes in the following form. 1=700MW, 2=1400MW, 3= 2400MW

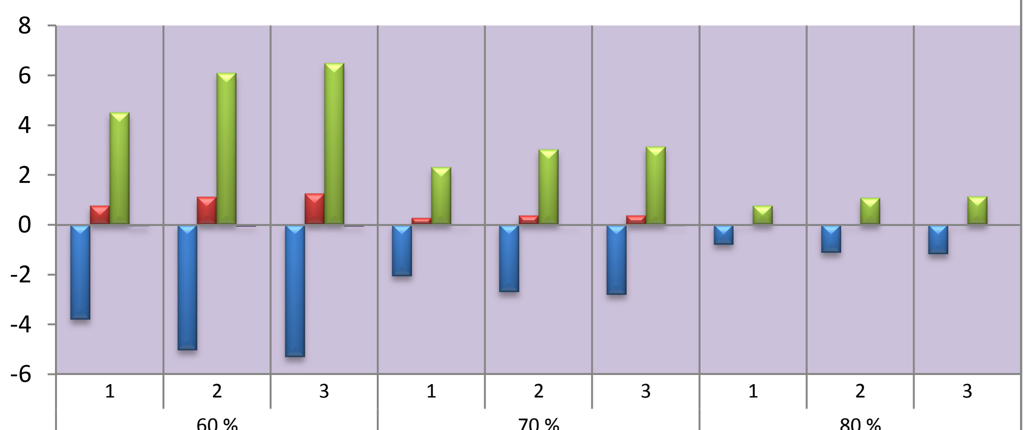
5.2.1 Production and consumption

As we discussed for the case of planned upgrade, as long as we have initial price difference, suppliers tend to compete for demand and hence low production cost suppliers increase their production and those with high production cost decrease theirs. Figure 26 and Figure 27 summarizes the impact of increasing the transmission capacity further on both countries consumption and production.



	60% 1	60% 2	60% 3	70% 1	70% 2	70% 3	80% 1	80% 2	80% 3
NO1 production (TWh)	1.13	1.423	1.43	2.085	2.759	2.814	3.173	4.411	4.618
NO1 consumption (TWh)	-0.035	-0.032	-0.027	-0.205	-0.279	-0.286	-0.206	-0.35	-0.382
DK1 production (TWh)	-1.139	-1.419	-1.42	-2.243	-2.97	-3.03	-3.304	-4.648	-4.88
DK1 consumption (TWh)	0.026	0.036	0.037	0.048	0.067	0.069	0.075	0.113	0.12

Figure 26: Production and consumption change comparison of the policies under wet year



	60 % 1	60 % 2	60 % 3	70 % 1	70 % 2	70 % 3	80 % 1	80 % 2	80 % 3
NO1 production (TWh)	-3.794	-5.036	-5.3	-2.055	-2.689	-2.797	-0.795	-1.113	-1.165
NO1 consumption (TWh)	0.769	1.13	1.248	0.277	0.365	0.379	-0.021	-0.022	-0.021
DK1 production (TWh)	4.509	6.099	6.479	2.301	3.015	3.137	0.763	1.077	1.13
DK1 consumption (TWh)	-0.054	-0.067	-0.069	-0.032	-0.039	-0.04	-0.012	-0.014	-0.015

Figure 27: Production and consumption change comparison of the policies under dry year

Increasing the transmission capacity by 1400MW leads to a further increase in the supply NO1 and a decrease in DK1 supply for wet year on average. For example, when IRL is

60%, from Figure 26, we see that, it leads to on average a further increase of 25.93% in NO1's supply and 24.58% decrease of DK1's supply compared to the initial 700MW upgrade. If we further upgrade the transmission capacity by 2100MW, though we see on average an increase in NO1's supply and a decrease in that of DK1's, the change is very small. For example, we only see 0.49% average increase in NO1's supply and 0.07% decrease in that of DK1's for 60% IRL when we compare it with the outcome of increasing the capacity by 1400MW.

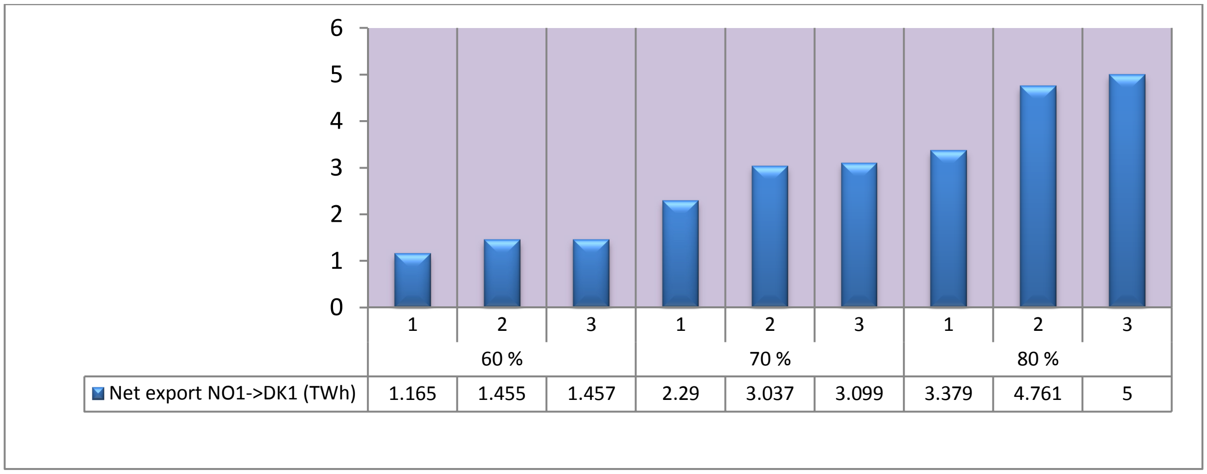
For a dry year, further expansion of the transmission capacity leads to a further increase in DK1's supply and decrease in NO1's supply. For example, when IRL is 60% further increasing the transmission capacity by 1400MW, leads NO1 to decrease its supply and DK1 to increase its supply by 33% and 35% respectively compared with the planned upgrade. However, expanding the capacity by 2100MW has no significant impact. For instance, for the same IRL, NO1's supply decreases only by 5% and that of DK1's increases by 6% compared with the prediction we have for 1400MW.

On the other hand demand does not change that much, it is inelastic (not vertical) to price changes as the result of capacity expansion[12]. The highest demand change is for NO1 under dry year with 60% IRL. Further upgrading the transmission capacity by 1400 MW and 2100 MW leads to an increase in NO1's demand by 45% and 10% respectively.

5.2.2 Net export

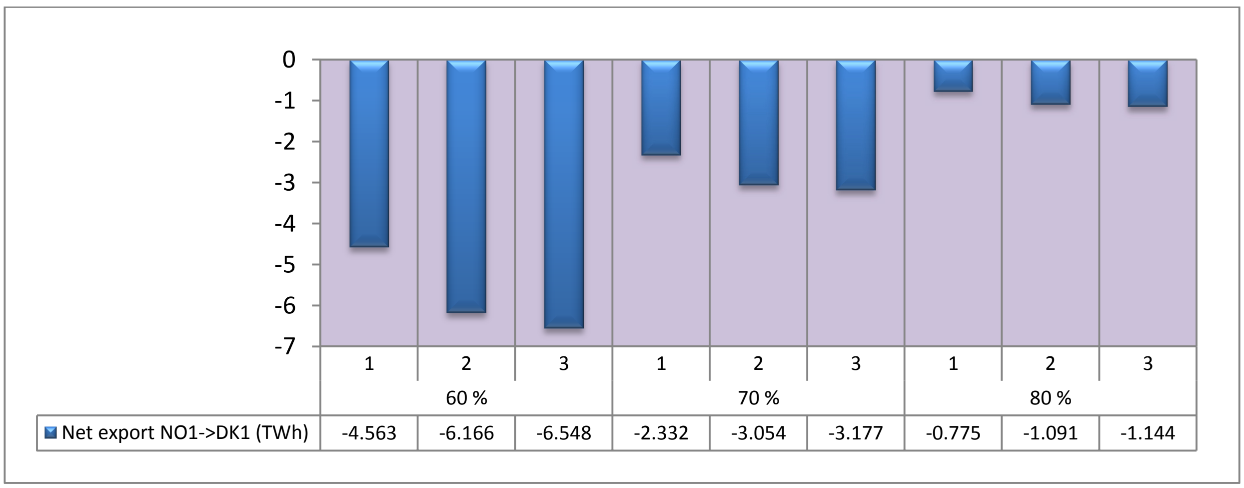
Transmission line expansion decreases congestion and increases electricity flow across regions. Figure 28 and Figure 29 summarize the further increase in net export as we keep on upgrading the transmission capacity.

[12] We can see by how much demand respond to price changes from our demand models under subsection 5.1.



	60 % 1	60 % 2	60 % 3	70 % 1	70 % 2	70 % 3	80 % 1	80 % 2	80 % 3
Net export NO1->DK1 (TWh)	1.165	1.455	1.457	2.29	3.037	3.099	3.379	4.761	5

Figure 28: Net export changes for the four polices under wet year



	60 % 1	60 % 2	60 % 3	70 % 1	70 % 2	70 % 3	80 % 1	80 % 2	80 % 3
Net export NO1->DK1 (TWh)	-4.563	-6.166	-6.548	-2.332	-3.054	-3.177	-0.775	-1.091	-1.144

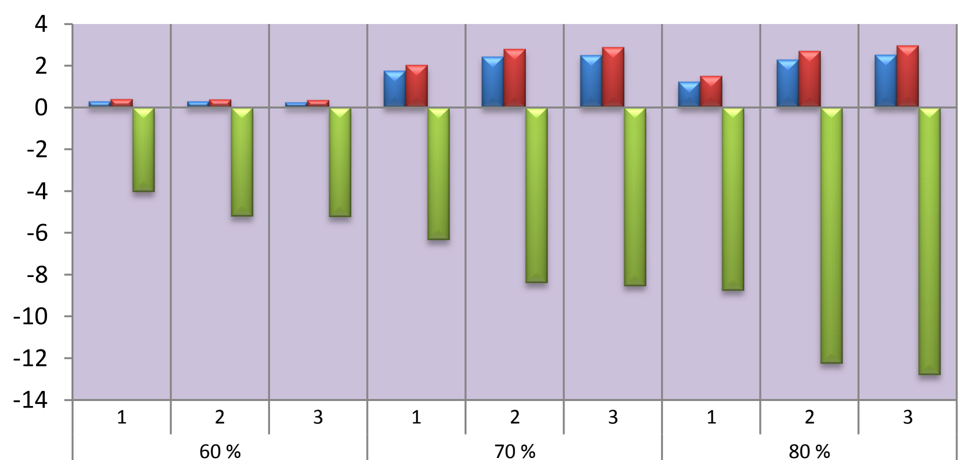
Figure 29: Net export changes for the four policy changes under dry year

As we can see from Figure 28, further upgrading the transmission capacity by 1400MW increases the net export (NO1 to DK1). For instance, for 60% and 80% IRLs it increases net export by 28% and 41% respectively. If we keep on upgrading the transmission capacity say by 2100MW, the net export increases but by a very small number. For the same IRLs it only increases export by 0.14% and 5% respectively compare to the outcomes of transmission expansion by 1400MW.

From Figure 29, we see that under a dry year, further upgrading the transmission capacity by 1400MW leads to an increase of net export (DK1 to NO1) on average. For example, net export increases by 35% and 41% for 60% and 80% IRLs respectively. However further upgrading the transmission capacity by 2100MW makes no significant difference. For the same IRLs, it only increase net export by 6% and 5% respectively relative to the increase under 1400MW.

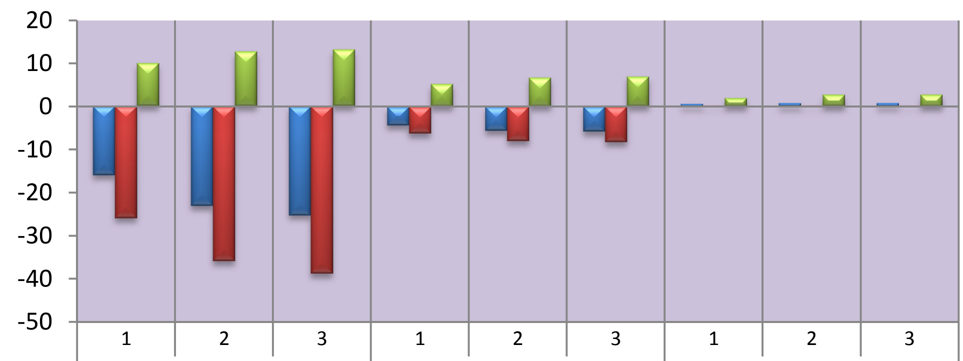
5.2.3 Change in Electricity Prices

Electricity price changes as export/import changes as the result of transmission expansion. Figure 30 and Figure 31 summarizes the price changes from the transmission upgrades



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
SYS price (EUR/MWh)	0.305	0.293	0.243	1.771	2.438	2.503	1.234	2.287	2.525
NO1 price (EUR/MWh)	0.403	0.397	0.34	2.046	2.812	2.885	1.515	2.705	2.966
DK1 price (EUR/MWh)	-4.016	-5.18	-5.226	-6.315	-8.369	-8.529	-8.759	-12.24	-12.778

Figure 30: Changes in average prices for the four polices under wet year



	60 % 1	60 % 2	60 % 3	70 % 1	70 % 2	70 % 3	80 % 1	80 % 2	80 % 3
SYS price (EUR/MWh)	-15.991	-23.003	-25.213	-4.321	-5.59	-5.781	0.61	0.784	0.792
NO1 price (EUR/MWh)	-25.946	-35.762	-38.665	-6.142	-7.925	-8.204	0.215	0.236	0.219
DK1 price (EUR/MWh)	9.951	12.734	13.171	5.216	6.678	6.908	1.932	2.642	2.748

Figure 31: Changes in average prices for the four policies under dry year

As we can see from Figure 30, increasing the transmission capacity further by 1400MW leads to an increase in NO1's and system price and a decrease in DK1's price for wet year. For instance, for 80% IRL NO1's price and system price increase by 79% and 85% respectively and DK1's decreases by 40% compared with the changes we have under the planned upgrade. If we further increase the transmission capacity by 2100MW, though we still see a change in these prices the magnitude is small. For the same IRL mentioned above, this further upgrade only leads to a 10% increase in NO1's and a 4% decrease in DK1's price. However, we notice that the system price increases by smaller percentage compared with the outcome under 1400MW when we have a wet year with 60% IRL.

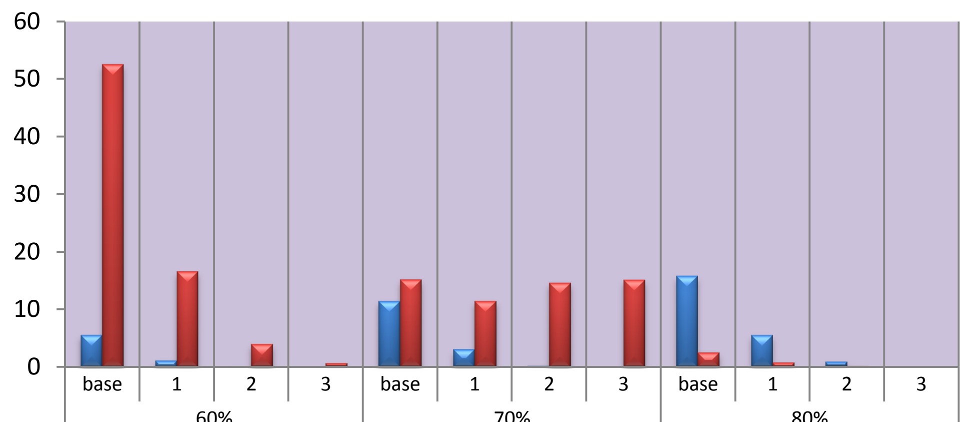
From Figure 31, we can see that when we have a dry year, further upgrading the transmission capacity by 1400MW leads to a further decrease in NO1's and the system price and increase of DK1's price on average when the IRLs are 60% and 70%. For 60% IRL, it decrease the system price and NO1's price by 43% and 38% and increase DK1's price by 28%. For 80% IRL, it leads to a further increase in the system and NO1's price as well as DK1's price on average[13]. Further upgrading the capacity by 2100MW moves

[13] The average increase of NO1's price for dry year with 80% IRL follows the same reasoning we gave for the case of planned upgrade.

the prices in the same direction. However, the changes are very small compared with the outcome under 1400MW.For 60% IRL, the change is only 10% and 8% decrease in system and NO1's price and 3% increase in DK1's price.

Price difference

We used the price differences of the base case and policy change prices to show if the increase in the transmission capacity leads to price convergence. Figure 32 shows us whether or not further transmission upgrades leads to a more competitive market.



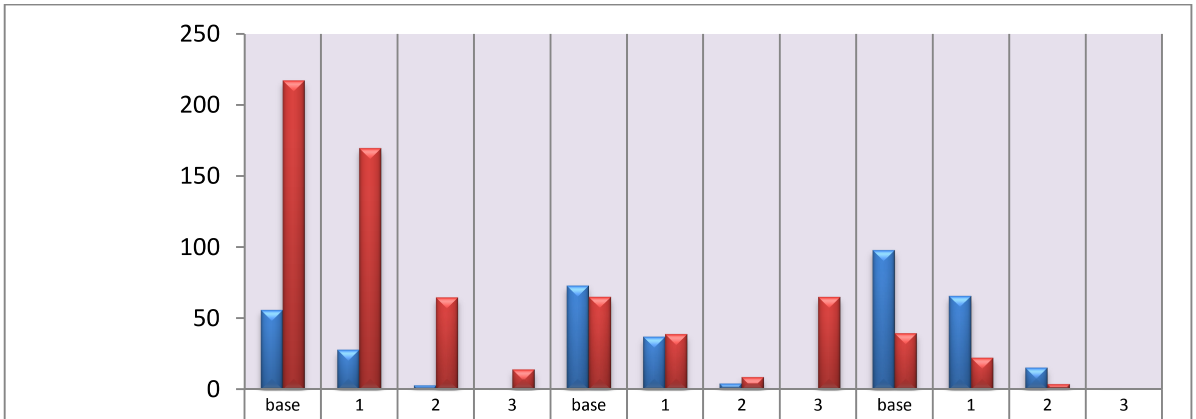
	base	1	2	3	base	1	2	3	base	1	2	3
	60%				70%				80%			
Wet year (EUR/MWh)	5.57	1.15	0.01	0.00	11.41	3.05	0.23	0.00	15.78	5.51	0.84	0.04
Dry year (EUR/MWh)	52.45	16.55	3.95	0.61	15.13	11.36	14.60	15.11	2.53	0.81	0.12	0.00

Figure 32: Prices differences for all policies and base case

As we can see from Figure 32, further increasing the transmission capacity decreases the price differences. For example, when IRL is 60%, increasing the transmission capacity by 1400MW decreases the price difference on average by 99% and 76% for wet and dry year respectively. For 80% IRL, price difference decreases on average by 85% for both wet and dry years. Increasing the transmission capacity by 2100MW further decreases and eliminates in some scenarios the price differences for wet year with any level of IRL and for dry year with 60% and 80% IRLs.

5.2.4 Congestion rent

We used the actual values for base as well as policy change scenarios in order to show how increasing the transmission capacity affects the congestion rent.



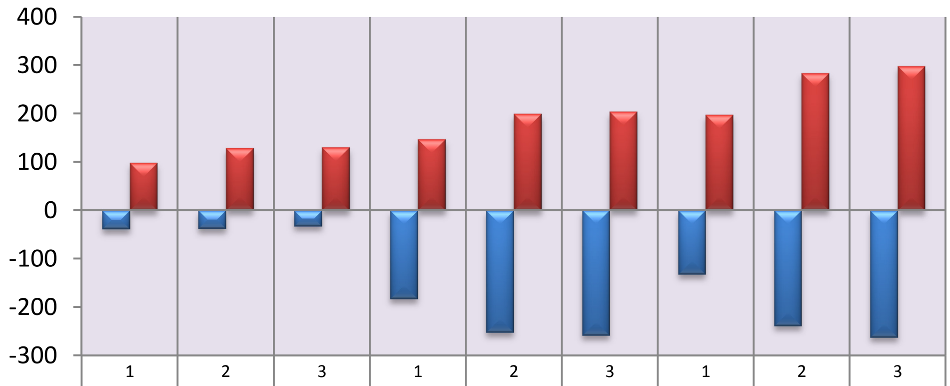
	60%				70%				80%			
	base	1	2	3	base	1	2	3	base	1	2	3
Wet year (EUR/MWh)	55.76	27.806	2.807	0.033	72.66	36.781	4.128	0.003	97.66	65.806	15.03	0.738
Dry year (EUR/MWh)	217.08	169.491	64.647	13.76	64.89	38.605	8.478	64.89	39.45	22.221	3.674	0.039

Figure 33: Congestion rent changes for all policies and base case scenarios

As we can see from Figure 33, further increasing the transmission capacity leads to a decrease in congestion rent as it changes the price difference and trade between the countries. For example, when NO1 has 60% IRL, increasing the transmission capacity by 1400 MW on average decreases congestion rent by 90% and 62% for wet and dry year respectively. For 80% IRL, it leads to 77% and 84% further decrease of the congestion rent on average. These are huge decrease compared to the base as well as the planned expansion scenarios. Increasing the transmission capacity by 2100MW further decreases the congestion rent. It is even almost zero in some scenarios. For example, for wet and dry year respectively, it further decreases congestion rent on average by 99% and 79% for 60% IRL and by 95% and 99% for 80% IRL.

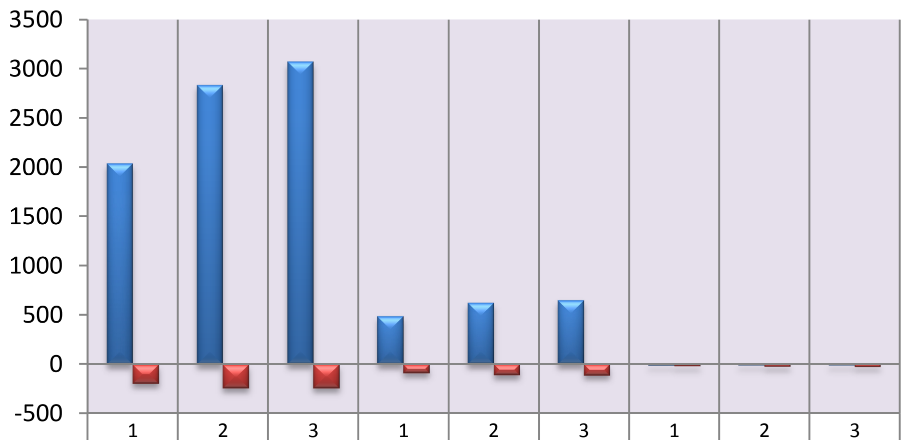
5.2.5 Welfare analysis

5.2.5.1 Consumer's surplus



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Change CS in NO1 (mill EUR)	-38.297	-37.82	-32.597	-182.93	-252.055	-258.707	-132.136	-239.578	-262.789
Change CS in DK1 (mill EUR)	96.954	127.86	129.399	146.917	198.949	203.25	196.378	283.332	297.906

Figure 34: Change in consumer's surplus under all policies for wet year



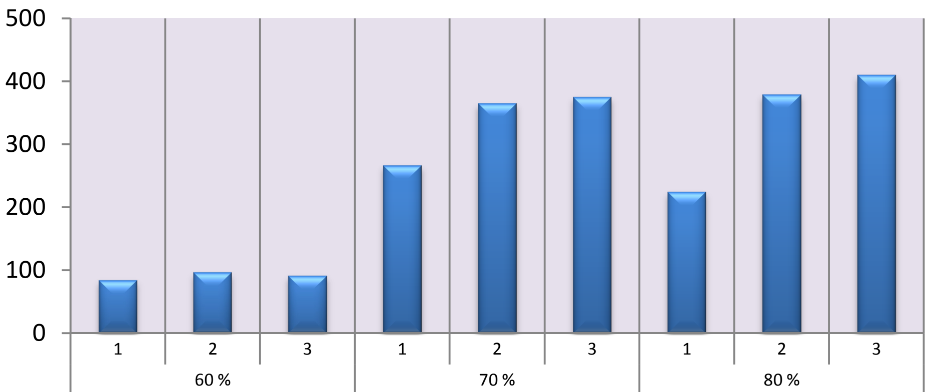
	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Change CS in NO1 (mill EUR)	2035.696	2831.176	3071.247	483.122	623.07	644.942	-14.439	-14.463	-12.825
Change CS in DK1 (mill EUR)	-195.986	-242.499	-245.794	-89.462	-110.553	-113.446	-19.864	-27.287	-28.539

Figure 35: Change in consumer's surplus under all prices for a dry year

As we can from Figure 34, for wet year further increasing the transmission capacity by 1400MW amplifies the increase of DK1's consumer's surplus and decrease of NO1's consumer’s surplus. For instance for 80% IRL, NO1’s consumer’s surplus further decreases on average by 81% and DK1’s consumer’s surplus increases by 41%. Further increasing the transmission capacity by 2400MW has still a room for changing the consumer’s surplus in both countries but when we compare it with the change we predicted for 1400MW transmission line expansion, the change is insignificant. For the above mentioned IRL, it decreases NO1’s consumer’s surplus by10% and increases DK1’s by 5%. However, when we have 60% IRL, further upgrades of the transmission capacity by 1400MW and 2100MW decreases the NO1’s consumer loss by 1.25% and 14% respectively. This is due to the price changes under this scenario.

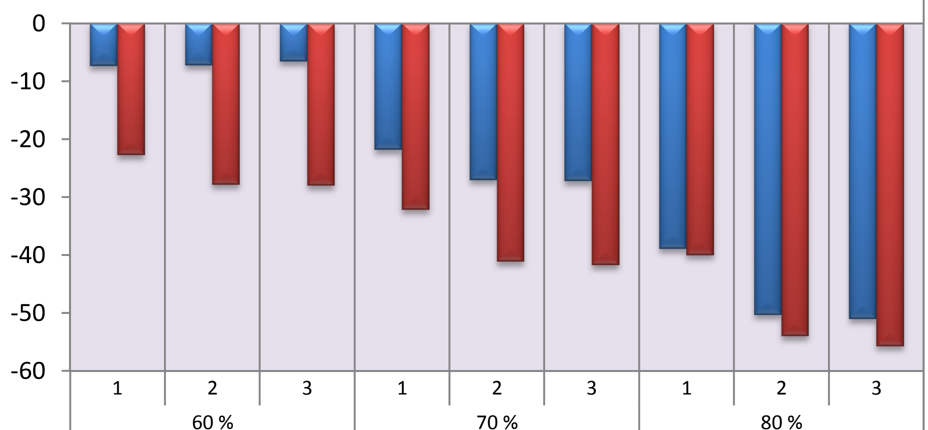
For a dry year in which NO1’s is importing ,as we can see from Figure 35, further increasing the transmission capacity by 1400MW leads to an increase in NO1’s consumer surplus and decrease in that of DK1’s on average for 60% and 70% initial reservoir levels. For example under 60% IRL, NO1’s consumer’s surplus further increased on average by 39% and decreased DK1’s by 24%.For 80% initial reservoir level, increasing the transmission capacity leads to a decrease in both countries consumer’s surpluses. As we said for the above scenarios, here also, increasing the transmission capacity further by 2400MW has no such significant impact compared with the outcome of 1400MW.

5.2.5.2 Producer's surplus



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Revenue hydro NO1 (mill EUR)	83.925	95.814	90.819	265.92	365.098	374.314	224.309	378.525	410.247

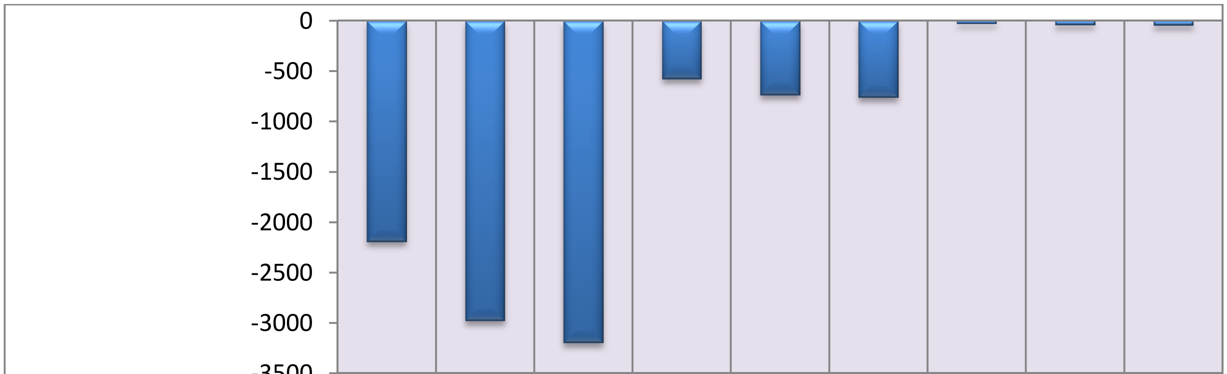
Figure 36: Hydro revenue for all polices under wet year



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Revenue wind DK1 (mill EUR)	-7.355	-7.243	-6.564	-21.749	-27.031	-27.158	-38.843	-50.283	-50.931
PS thermal DK1 (mill EUR)	-22.619	-27.725	-27.884	-32.096	-41.029	-41.632	-39.931	-53.889	-55.652

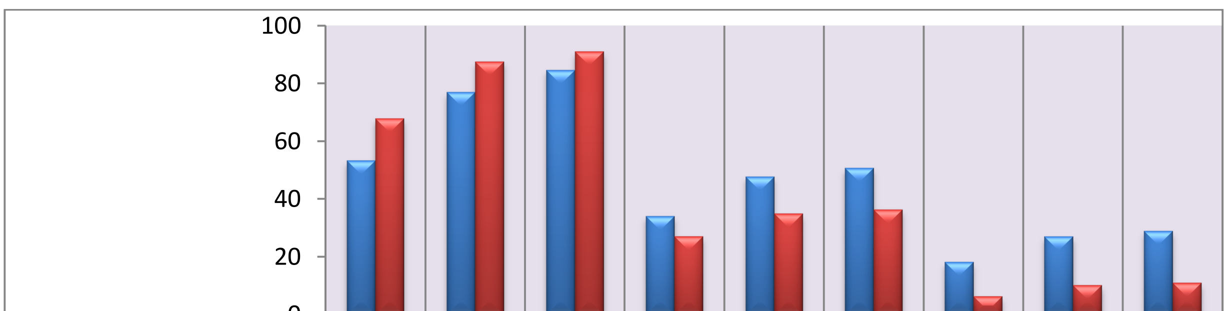
Figure 37: Wind revenue &thermal PS for all polices under wet year

As we can see from Figure 36 and Figure 37, for a wet year, further increasing the transmission capacity by 1400MW leads to an increase in hydro revenue and a decrease in wind revenue & thermal producer's surplus. For example when IRL is 80%, hydro revenue further increases on average by 69% and decreases wind revenue and thermal producer's surplus by 30% and 35% respectively. Increasing the transmission capacity by 2400MW leads to a further increase, in hydro revenue (by 8%) and a decrease in wind revenue (by 1.3%) & thermal producer's surplus (by 3%). However, when we have 60% IRL, the changes in hydro and wind revenue are even lower than that of what we have under 1400MW.



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Revenue hydro NO1 (mill EUR)	-2191.993	-2974.106	-3193.667	-577.75	-735.757	-760.101	-28.061	-43.083	-46.834

Figure 38: Hydro revenue for all policies under dry year.

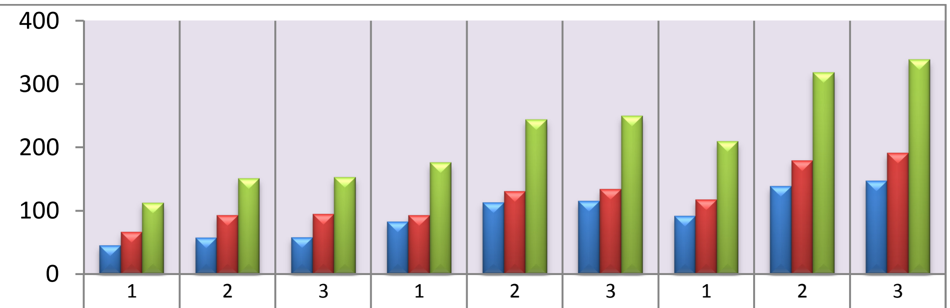


	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
Revenue wind DK1 (mill EUR)	53.373	77.055	84.577	34.042	47.657	50.817	18.25	27.08	28.86
PS thermal DK1 (mill EUR)	67.875	87.555	91.052	27.037	34.886	36.327	6.395	10.269	10.947

Figure 39: Wind revenue and thermal PS for all policies under dry year.

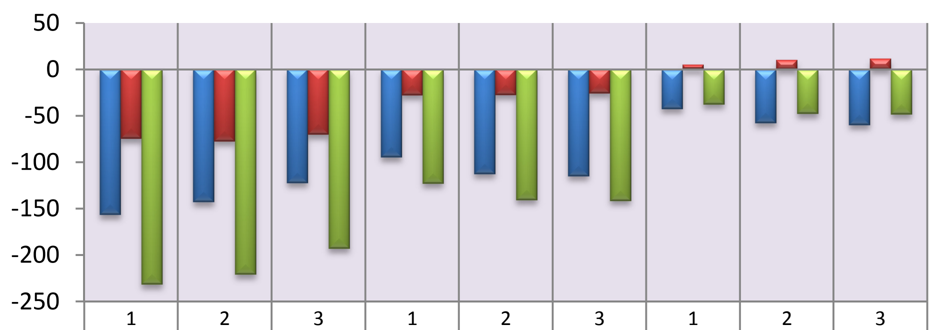
Figure 38 and Figure 39 show that for a dry year further upgrades of the transmission capacity leads to a further decrease in Hydro revenue and an increase of wind revenue and thermal producer's surplus. Upgrading the capacity by 1400 MW with a 60% IRL, on average hydro revenue further decreases by 36% and wind revenue and thermal producer’s surplus increase by 44% and 29% respectively. Further upgrading the transmission capacity by 2100MW does not have significant change compared to the outcome we have for 1400MW. For 60% IRL it only leads to an average further decrease of hydro revenue by 7% and an average increase in wind revenue and thermal producer’s surplus by 10% and 4% respectively.

5.2.5.3 Overall welfare change



	60 %			70 %			80 %		
	1	2	3	1	2	3	1	2	3
NO1 welfare change (mill EUR)	45.628	57.995	58.222	82.991	113.043	115.607	92.173	138.947	147.458
DK1 welfare change (mill EUR)	66.98	92.892	94.951	93.073	130.888	134.46	117.604	179.16	191.323
Net welfare change (mill EUR)	112.609	150.886	153.173	176.063	243.931	250.067	209.776	318.107	338.781

Figure 40: Overall welfare change for all policies under wet year.



	60%			70%			80%		
	1	2	3	1	2	3	1	2	3
NO1 welfare change (mill EUR)	-156.296	-142.931	-122.42	-94.628	-112.687	-115.16	-42.5	-57.546	-59.66
DK1 welfare change (mill EUR)	-74.739	-77.889	-70.164	-28.383	-28.01	-26.302	4.781	10.061	11.269
Net welfare change (mill EUR)	-231.035	-220.82	-192.584	-123.011	-140.697	-141.462	-37.719	-47.485	-48.391

Figure 41: Overall welfare change for all policies under dry year.

From Figure 40 for a wet year, we can see that increasing the transmission capacity further by 1400MW leads to an increase in both countries welfare as well as net welfare. for instance for 80% and 60% IRLs respectively, NO's welfare increases by 51% and 27% ; DK1's welfare increases by 52% and 39% resulting in an average increase in net welfare by 52% and 34%. Further upgrading the transmission capacity by 2100MW has small impact in increasing welfare. On average for 80% and 60% IRLs it increases NO1's welfare on average by 6% and 0.4%; DK1's welfare only by 7% and 2% and net welfare on average increases only by 7% and 1.5%.

For a dry year, as it is shown on Figure 41, the impact of further increasing the transmission capacity on both countries as well as net welfare depends on the IRL. If we take 80%, NO1's welfare on average further decreases by 35%; DK1's welfare further increases on average by 110%. Because the NO1's loss outweighs the gain of DK1's, net welfare decreases on average by 26%.Further upgrading the transmission capacity by 2100MW leads a further decrease in NO1 and net welfare on average by 4% and 2% respectively. On the other hand, DK1's welfare further improves by 12%. If we take 60% IRL, increasing the transmission capacity by 1400MW further increases the welfare loss of Dk1 and decrease the welfare loss of NO1 and net welfare. NO1 welfare loss decreases on average by 9%; DK1's welfare loss increases on average by 4.2% and net welfare improves on average by 4.4%.Further upgrading the transmission capacity by 2100MW decreases both countries welfare loss on average.NO1's welfare loss decreases by 14%; DK1's welfare loss decrease by 10% and net welfare improves by 13% compare with the outcome for 1400MW transmission upgrade.

6. Conclusion

We analyzed the economic and social welfare impact of the new transmission capacity expansion, Skagerrak 4, using simulation analysis. Findings from this study reveal important features of the new transmission expansion with respect to its impact on key variables such as supply, net export, prices, and congestion rest as well as on overall welfare.

Our findings show that the transmission capacity upgrade permits the flow of low cost generation (hydro power in wet year and thermal power in dry year) to high cost generation areas (Norway in dry year and Denmark in wet year). Accordingly, South Norway becomes more of a peak load supplier and West Denmark becomes mostly a base load supplier. However, when inflow as well as initial reservoir content is very low in South Norway, increasing the transmission capacity leads to West Denmark increase its peak load power generation and export throughout the day. On the other hand, when inflow and initial reservoir level are very high, Norway increase its supply and export for all hours of the day. This implies that as the result of the transmission line expansion there is improvement in efficiency in the market as the cheapest generators are optimizing their output and the more expensive generators are decreasing their supply.

With regards to prices, the results show that exporting country price increases and that of importing country decreases. That is, South Norway's price increases for high inflow and reservoir level as well as peak hours and it decreases for low inflow and reservoir level. In contrast, prices in west Denmark decreases when south Norway has more water as import becomes cheaper and during peak hours while during the off-peak load hours, price increases as west Denmark exports more during these hours. Following the path of changes in the flow of electricity, when it is extremely wet in south Norway, price increase for all hours of the day and when it is extremely dry in Norway, west Denmark's price increases for all hours of the day.

In terms of price differences and price volatility, we found that increasing the transmission capacity leads the two prices to converge. For a dry year, increasing the transmission capacity decreases price volatility and price spikes. However we still have price spikes for wet year. Hence the transmission line upgrade does not fully eliminate price volatility.

When we look at the welfare impact, upgrading the interconnection by the planned level of capacity does improve the social welfare when South Norway has high inflow. However, it leads to winners and losers. That is, South Norway's consumers and west Denmark's suppliers lose while west Denmark's consumers and South Norway's suppliers gain. For a year with low water inflow into the reservoirs of south Norway, transmission capacity upgrade leads to a welfare loss as the gains by south Norway's consumers and west Denmark's producers is too small to outweigh the loss incurred by south Norway's suppliers and west Denmark consumers. However, west Denmark's welfare improves when south Norway's initial reservoir level is high. Therefore, from net welfare improvement point of view, increasing transmission capacity creates a loss in net social welfare if the given year is a dry year.

Further upgrading the transmission capacity by 1400MW has still a room for welfare improvement in wet year, as it increases south Norway's supply and export while it decreases the supply of west Denmark as more cheap and surplus hydro power is available. But for a dry year, it further decreases the net welfare gain even if west Denmark's welfare improves when south Norway has high initial reservoir level. The results show that upgrading the transmission capacity by 2100MW has no significant impact on welfare. That is, expanding the capacity by 1400MW leads to price convergence and there is no need to further transport electricity from another country if domestic price and import prices are equal.

In summary, the implication of this study is that the net impact of increasing the transmission capacity depends on the availability of water in reservoirs of NO1 as well as the inflow. However we have not controlled for the wind power and how changes in it might affect the results. We have not also seen the impact of changes in supply and demand elasticity changes. Therefore, there is still a room for further studies.

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Appendix A: structural modeling summaries

Supply

Supply of NO1

Prod_no1	0.367(0.063)***	hr9	-0.030(0.016)*
lninflow	-0.03(0.033)	hr10	-0.031(0.017)*
lnrhsort	2.76(0.265)***	hr11	-0.034(0.017)**
Trend base	0.00(0.00)***	hr12	-0.037(0.017)**
Trigonometric cycle(sine)	-0.004(0.039)	hr13	-0.038(0.016)**
Trigonometric cycle(cosine)	0.135(0.044)***	hr14	-0.040(0.015)***
lnP_oil	0.667(0.180)***	hr15	-0.041(0.014)***
Gov't 5-year bonds(solb5)	-0.180(0.049)***	hr16	-0.043(0.013)***
lnp_co2	0.495(0.079)***	hr17	-0.040(0.014)***
Dummy for co2 market	1.445(0.251)***	hr18	-0.038(0.015)***
hr2	-0.010(0.004)***	hr19	-0.039(0.016)***
hr3	-0.027(0.007)***	hr20	-0.039(0.015)***
hr4	-0.040(0.008)***	hr21	-0.037(0.013)***
hr5	-0.044(0.008)***	hr22	-0.033(0.011)***
hr6	-0.030(0.004)***	hr23	-0.026(0.009)***
hr7	-0.037(0.006)***	hr24	-0.020(0.004)***
hr8	-0.046(0.013)***	constants	-3.11(1.088)***
Observations 52244			
*Significant at 10%;	** significant at 5%;	*** significant at 1%	

Supply of DK1

lnsup_dk1	0.931(0.069)***	hr10	-0.0003(0.029)
lnpgas	0.13(0.549)	hr11	0.016(0.030)
lnp_coal	0.617(0.594)***	hr12	0.027(0.030)
lnp_co2	0.221(0.564)***	hr13	0.002(0.028)
Dummy for co2 market	0.256(0.178)*	hr14	-0.006(0.028)
Trend base	0.000(0.000)***	hr15	-0.016(0.028)
Trigonometric cycle(sine)	0.128(0.164)***	hr16	-0.027(-0.027)
Trigonometric cycle (cosine)	0.271(0.335)***	hr17	-0.008(0.025)
hr2	0.001(0.140)	hr18	0.056(0.026)
hr3	-0.038(0.019)**	hr19	0.064(0.025)**
hr4	0.091(0.0223)***	hr20	0.050(0.024)**
hr5	-0.098(0.023)***	hr21	0.054(0.023)**
hr6	-0.036(0.020)*	hr22	0.072(0.022)***
hr7	-0.075(0.025)***	hr23	0.072(0.020)***
hr8	-0.026(0.028)	hr24	0.095(0.019)***
hr9	-0.008(0.029)	Constants	-6.291(0.550)***
Observations 52554			
*Significant at 10%;	** significant at 5%;	*** significant at 1%	

Demand

Demand of NO1

lnprice_no	-0.037(0.004)***	hr10	0.218(0.002)***
lnhd	-0.056(0.002)***	hr11	0.230(0.002)***
lnhd2	0.045(0.001)***	hr12	0.230(0.002)***
Daylight in Oslo	-0.034(0.00)***	hr13	0.227(0.002)***
lnipi	0.224(0.011)***	hr14	0.221(0.002)***
Dummy for working days	0.084(0.002)***	hr15	0.216(0.002)***
Trend base	-0.00(0.00)**	hr16	0.205(0.002)***
Trigonometric cycle(sine)	0.050(0.002)***	hr17	0.202(0.002)***
Trigonometric cycle (cosine)	0.143(0.003)***	hr18	0.199(0.002)***
hr2	-0.035(0.001)***	hr19	0.192(0.001)***
hr3	-0.053(0.001)***	hr20	0.182(0.001)***
hr4	-0.059(0.001)***	hr21	0.163(0.001)***
hr5	-0.051(0.001)***	hr22	0.137(0.001)***
hr6	-0.025(0.001)***	hr23	0.095(0.001)***
hr7	0.049(0.002)***	hr24	0.044(0.001)***
hr8	0.147(0.002)***	Constants	7.918(0.059)***
hr9	0.195(0.002)***		
Observations 52412			
*Significant at 10%;	** significant at 5%;	*** significant at 1%	

Demand of DK1

lnprice_dk1	-0.014(0.025)*	hr10	0.383(0.011)***
trend base	-0.00(0.00)*	hr11	0.403(0.013)***
hddk	0.016(0.002)***	hr12	0.399(0.013)***
lnhdden	-0.022(0.004)***	hr13	0.370(0.012)***
Trigonometric cycle (sine)	0.003(0.004)	hr14	0.364(0.011)***
Trigonometric cycle (cosine)	0.054(0.007)***	hr15	0.342(0.010)***
Dummy for holidays	-0.003(0.008)	hr16	0.309(0.009)***
Dummy for working days	0.23(0.007)***	hr17	0.322(0.009)***
ds	-0.093(0.006)***	hr18	0.393(0.012)***
hr2	-0.045(0.001)***	hr19	0.379(0.012)***
hr3	-0.064(0.003)***	hr20	0.324(0.011)***
hr4	-0.069(0.005)***	hr21	0.269(0.010)***
hr5	-0.057(0.005)***	hr22	0.227(0.009)***
hr6	-0.002(0.002)***	hr23	0.167(0.008)***
hr7	0.135(0.003)***	hr24	0.078(0.005)***
hr8	0.292(0.008)***	constant	7.422(0.071)***
hr9	0.363(0.011)***		
Observations 52584			
*Significant at 10%;	** significant at 5%;	***significant at 1%	

Appendix B: Simulation Summaries

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===        Baseline simulation summary       ===
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Key variable	1 (07)	2 (05)	3 (06)	4 (08)	5 (07)	6 (05)	7 (06)	8 (08)	9 (07)	10 (05)	11 (06)	12 (08)
Initial reservoir (perc)	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	80.0	80.0	80.0	80.0
Total NO1 inflow (TWh)	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75
Total DK1 wind prod (TWh)	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71
Other NO1 net export (TWh)	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79
Other DK1 net export (TWh)	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16
Average NO1 -> DK1 cap (GW)	751.13	773.80	551.38	688.91	751.13	773.80	551.38	688.91	751.13	773.80	551.38	688.91
Average DK1 -> NO1 cap (GW)	702.51	727.22	517.23	696.30	702.51	727.22	517.23	696.30	702.51	727.22	517.23	696.30
Total NO1 production (TWh)	95.37	88.99	78.36	94.05	98.30	92.69	81.11	96.87	100.18	95.20	84.51	98.88
Total NO1 consumption (TWh)	87.03	84.27	82.97	86.00	88.01	85.17	84.35	87.06	88.92	86.15	85.35	88.10
Total DK1 production (TWh)	23.53	24.98	28.71	23.57	21.61	22.22	27.35	21.84	20.66	20.71	24.98	20.89
Total DK1 consumption (TWh)	20.81	21.03	20.87	20.67	20.85	21.07	20.89	20.70	20.87	21.10	20.92	20.72
Average SYS price (EUR/MWh)	37.58	45.65	94.47	57.50	28.30	35.04	65.33	41.18	22.20	26.44	49.54	30.13
Average NO1 price (EUR/MWh)	37.48	45.75	108.06	57.78	27.92	34.75	67.76	40.59	21.75	26.00	50.11	29.42
Average DK1 price (EUR/MWh)	43.05	47.00	55.61	64.01	39.33	41.29	52.63	58.80	37.53	38.05	47.58	56.15
Total net export (TWh)	1.89	0.83	-4.44	2.26	3.85	3.64	-3.07	4.02	4.82	5.17	-0.67	4.99
Congestion rent (mill EUR)	55.76	31.14	217.08	111.23	72.66	43.91	64.89	126.68	97.66	76.60	39.45	165.63
Total overflow (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.79	0.79	0.00	0.00
Overflow loss (mill EUR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.51	20.95	0.00	0.00
Final reserve level (TWh)	40.37	42.59	34.68	38.08	42.99	44.45	37.50	40.82	44.88	46.72	39.66	44.37
Final reserve level (perc)	72.57	76.56	62.34	68.44	77.29	79.91	67.40	73.38	80.68	83.98	71.28	79.76
CSx in NO1 (mill EUR)	-3502.96	-3895.66	-9155.49	-5219.88	-2619.67	-2968.13	-5802.98	-3678.23	-2056.37	-2244.64	-4311.69	-2682.15
CSx in DK1 (mill EUR)	-945.23	-1018.88	-1229.26	-1388.74	-868.03	-900.84	-1157.61	-1284.43	-833.28	-839.26	-1044.10	-1233.89
Revenue hydro (mill EUR)	3646.40	3956.39	8332.94	5433.72	2793.10	3120.03	5415.72	3926.38	2210.30	2395.57	4143.37	2895.56
Revenue wind DK1 (mill EUR)	241.19	232.85	248.21	322.84	214.08	201.06	238.19	295.90	199.13	179.11	216.36	274.40
PSx thermal DK1 (mill EUR)	114.38	135.46	203.87	218.01	98.20	104.37	177.51	186.39	92.98	92.00	142.45	175.44

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===        Policy #1 simulation summary      ===
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Key variable	1 (07)	2 (05)	3 (06)	4 (08)	5 (07)	6 (05)	7 (06)	8 (08)	9 (07)	10 (05)	11 (06)	12 (08)
Initial reservoir (perc)	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	80.0	80.0	80.0	80.0
Total NO1 inflow (TWh)	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75
Total DK1 wind prod (TWh)	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71
Other NO1 net export (TWh)	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79
Other DK1 net export (TWh)	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16
Average NO1 -> DK1 cap (GW)	1451.13	1473.80	1251.38	1388.91	1451.13	1473.80	1251.38	1388.91	1451.13	1473.80	1251.38	1388.91
Average DK1 -> NO1 cap (GW)	1402.51	1427.22	1217.23	1396.30	1402.51	1427.22	1217.23	1396.30	1402.51	1427.22	1217.23	1396.30
Total NO1 production (TWh)	96.50	89.41	74.56	95.22	100.39	93.88	79.05	99.11	103.36	97.49	83.72	102.09
Total NO1 consumption (TWh)	87.00	84.28	83.74	86.05	87.81	85.01	84.63	86.86	88.72	85.87	85.33	87.76
Total DK1 production (TWh)	22.39	24.58	33.22	22.48	19.37	20.89	29.65	19.45	17.36	18.20	25.74	17.41
Total DK1 consumption (TWh)	20.84	21.04	20.82	20.70	20.89	21.09	20.86	20.74	20.94	21.15	20.90	20.79
Average SYS price (EUR/MWh)	37.89	45.42	78.48	55.92	30.07	36.76	61.01	43.24	23.43	28.82	50.15	33.09
Average NO1 price (EUR/MWh)	37.89	45.47	82.11	56.06	29.96	36.71	61.61	43.05	23.27	28.71	50.33	32.80
Average DK1 price (EUR/MWh)	39.03	45.40	65.56	57.66	33.02	37.89	57.85	48.84	28.77	31.87	49.51	42.76
Total net export (TWh)	3.06	1.24	-9.01	3.38	6.14	4.99	-5.40	6.46	8.20	7.74	-1.44	8.54
Congestion rent (mill EUR)	27.81	10.95	169.49	68.73	36.78	15.90	38.61	76.12	65.81	40.95	22.22	120.73
Total overflow (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overflow loss (mill EUR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Final reserve level (TWh)	39.24	42.18	38.48	36.90	40.91	43.27	39.55	38.58	43.50	45.22	40.45	41.17
Final reserve level (perc)	70.53	75.82	69.16	66.34	73.54	77.78	71.10	69.35	78.20	81.28	72.71	74.00
CSx in NO1 (mill EUR)	-3541.26	-3878.29	-7119.79	-5069.84	-2802.60	-3126.72	-5319.86	-3885.19	-2188.51	-2459.92	-4326.13	-2970.06
CSx in DK1 (mill EUR)	-848.27	-973.81	-1425.25	-1238.06	-721.11	-815.32	-1247.07	-1054.88	-636.90	-693.60	-1063.96	-935.87
Revenue hydro (mill EUR)	3730.33	3958.77	6140.94	5321.71	3059.02	3334.60	4837.97	4257.41	2434.61	2698.15	4115.31	3328.84
Revenue wind DK1 (mill EUR)	233.83	236.57	301.58	311.15	192.33	194.35	272.23	261.60	160.28	158.97	234.61	219.07
PSx thermal DK1 (mill EUR)	91.76	124.74	271.75	174.99	66.11	84.92	204.55	121.48	53.05	60.50	148.84	96.56

Policy #2 simulation summary

Key variable	1 (07)	2 (05)	3 (06)	4 (08)	5 (07)	6 (05)	7 (06)	8 (08)	9 (07)	10 (05)	11 (06)	12 (08)
Initial reservoir (perc)	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	80.0	80.0	80.0	80.0
Total NO1 inflow (TWh)	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75
Total DK1 wind prod (TWh)	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71
Other NO1 net export (TWh)	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79
Other DK1 net export (TWh)	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16
Average NO1 -> DK1 cap (GW)	2151.13	2173.80	1951.38	2088.91	2151.13	2173.80	1951.38	2088.91	2151.13	2173.80	1951.38	2088.91
Average DK1 -> NO1 cap (GW)	2102.51	2127.22	1917.23	2096.30	2102.51	2127.22	1917.23	2096.30	2102.51	2127.22	1917.23	2096.30
Total NO1 production (TWh)	96.79	89.45	73.32	95.72	101.06	94.11	78.42	100.04	104.60	98.14	83.40	103.63
Total NO1 consumption (TWh)	87.00	84.29	84.10	86.09	87.73	84.97	84.71	86.78	88.57	85.75	85.33	87.59
Total DK1 production (TWh)	22.11	24.55	34.81	22.03	18.64	20.63	30.36	18.46	16.01	17.45	26.06	15.74
Total DK1 consumption (TWh)	20.85	21.04	20.80	20.71	20.91	21.10	20.85	20.77	20.98	21.17	20.90	20.83
Average SYS price (EUR/MWh)	37.87	45.21	71.46	55.11	30.74	37.21	59.74	44.10	24.48	29.89	50.32	34.67
Average NO1 price (EUR/MWh)	37.88	45.22	72.29	55.17	30.73	37.21	59.83	44.07	24.46	29.88	50.35	34.61
Average DK1 price (EUR/MWh)	37.87	45.13	68.35	55.09	30.96	37.27	59.31	44.91	25.29	30.23	50.22	36.62
Total net export (TWh)	3.35	1.27	-10.61	3.84	6.89	5.26	-6.12	7.47	9.58	8.51	-1.76	10.25
Congestion rent (mill EUR)	2.81	1.66	64.65	15.75	4.13	1.21	8.48	15.88	15.03	7.23	3.67	36.19
Total overflow (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overflow loss (mill EUR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Final reserve level (TWh)	38.94	42.13	39.72	36.41	40.24	43.04	40.18	37.65	42.27	44.57	40.77	39.63
Final reserve level (perc)	70.01	75.74	71.40	65.45	72.33	77.36	72.24	67.67	75.98	80.11	73.29	71.23
CSx in NO1 (mill EUR)	-3540.78	-3858.01	-6324.31	-4989.66	-2871.72	-3167.96	-5179.91	-3973.47	-2295.95	-2553.43	-4326.15	-3124.93
CSx in DK1 (mill EUR)	-817.37	-965.76	-1471.76	-1173.04	-669.08	-797.81	-1268.16	-957.06	-549.95	-649.98	-1071.38	-786.13
Revenue hydro (mill EUR)	3742.22	3941.15	5358.83	5261.37	3158.20	3386.73	4679.97	4401.72	2588.83	2818.49	4100.28	3566.05
Revenue wind DK1 (mill EUR)	233.94	238.84	325.26	311.61	187.05	194.46	285.84	250.42	148.84	155.74	243.44	198.93
PSx thermal DK1 (mill EUR)	86.65	123.31	291.43	161.02	57.17	82.21	212.40	99.53	39.09	53.98	152.72	64.90

Policy #3 simulation summary

Key variable	1 (07)	2 (05)	3 (06)	4 (08)	5 (07)	6 (05)	7 (06)	8 (08)	9 (07)	10 (05)	11 (06)	12 (08)
Initial reservoir (perc)	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	80.0	80.0	80.0	80.0
Total NO1 inflow (TWh)	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75	102.36	98.20	79.66	98.75
Total DK1 wind prod (TWh)	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71	6.17	5.51	5.12	5.71
Other NO1 net export (TWh)	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79	6.44	3.88	-0.17	5.79
Other DK1 net export (TWh)	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16	4.61	4.79	3.39	5.16
Average NO1 -> DK1 cap (GW)	2851.13	2873.80	2651.38	2788.91	2851.13	2873.80	2651.38	2788.91	2851.13	2873.80	2651.38	2788.91
Average DK1 -> NO1 cap (GW)	2802.51	2827.22	2617.23	2796.30	2802.51	2827.22	2617.23	2796.30	2802.51	2827.22	2617.23	2796.30
Total NO1 production (TWh)	96.80	89.44	73.06	95.77	101.12	94.12	78.31	100.22	104.80	98.22	83.35	104.02
Total NO1 consumption (TWh)	87.00	84.30	84.22	86.10	87.73	84.96	84.73	86.77	88.54	85.73	85.33	87.55
Total DK1 production (TWh)	22.11	24.57	35.19	22.00	18.58	20.61	30.49	18.28	15.78	17.36	26.11	15.32
Total DK1 consumption (TWh)	20.85	21.04	20.80	20.71	20.92	21.10	20.85	20.77	20.99	21.17	20.90	20.84
Average SYS price (EUR/MWh)	37.82	45.14	69.25	54.79	30.80	37.26	59.55	44.26	24.72	30.09	50.33	35.09
Average NO1 price (EUR/MWh)	37.83	45.14	69.39	54.80	30.80	37.26	59.55	44.26	24.72	30.09	50.33	35.09
Average DK1 price (EUR/MWh)	37.82	45.12	68.78	54.75	30.80	37.26	59.54	44.27	24.75	30.12	50.33	35.20
Total net export (TWh)	3.35	1.26	-10.99	3.88	6.95	5.27	-6.25	7.66	9.82	8.60	-1.81	10.69
Congestion rent (mill EUR)	0.03	0.34	13.76	1.18	0.00	0.00	0.20	0.12	0.74	0.65	0.04	2.63
Total overflow (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overflow loss (mill EUR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Final reserve level (TWh)	38.94	42.14	39.98	36.36	40.18	43.03	40.29	37.47	42.06	44.49	40.82	39.23
Final reserve level (perc)	70.00	75.75	71.87	65.35	72.23	77.34	72.43	67.36	75.61	79.98	73.38	70.52
CSx in NO1 (mill EUR)	-3535.56	-3850.88	-6084.24	-4956.86	-2878.38	-3171.85	-5158.04	-3989.95	-2319.16	-2570.56	-4324.51	-3165.64
CSx in DK1 (mill EUR)	-815.83	-965.39	-1475.05	-1163.36	-664.78	-797.25	-1271.05	-940.13	-535.38	-645.87	-1072.63	-749.04
Revenue hydro (mill EUR)	3737.22	3933.85	5139.27	5230.16	3167.41	3390.96	4655.62	4428.56	2620.55	2838.15	4096.53	3628.25
Revenue wind DK1 (mill EUR)	234.62	239.40	332.79	313.88	186.92	194.58	289.00	249.55	148.19	155.86	245.22	196.49
PSx thermal DK1 (mill EUR)	86.49	123.27	294.93	159.64	56.57	82.24	213.84	96.42	37.33	53.85	153.40	58.70