NORGES HANDELSHØYSKOLE
Bergen, 20.12.2012

Nordic Power market integration

- A market based approach to the price effects of increased Nordic – Continental power trade in the Nordic Market

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Masters thesis written as part of the Master of Science in Economics and Business administration at the Norwegian School of Economics, NHH. Profile in Energy, Natural resources and the Environment (ENE)

NORGES HANDELSHØYSKOLE

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Summary

Based on historical market data for 2011 this thesis models estimated effects that increased Nordic-Continental power trade potential would have had on trade and on Nordic prices during this year. The model used differs from most other models used to estimate trade effects as it focuses on realized market data contrasted to the more commonly used fundamental bottom up model of the power market.

The approach used in this work suggests that one extra interconnector combined with internal grid improvements lowers Nordic prices in a strained hydro situation with 4-5€ and raises the price level slightly more in a surplus situation. It also suggests that the Nordic system will import a significant amount of hourly price volatility even at this modest increase in trade capacity. Even though the hourly price volatility is probably overestimated, the estimate is likely to be more robust on the downward volatility. In other words the results suggest we are likely to import the very low prices experienced during nightly hours on the continent to a greater extent than the hourly peaks during midday. Further, the results suggest that internal grid improvements have a similar effect on price level as the actual added interconnector.

Price level effects are in line with other research and simulations from fundamental power market models, the hourly volatility effect is however suggested to be stronger in this market based model than what other research has suggested. Unless demand becomes more responsive to hourly price signals I believe that the estimations on the downward volatility to be pretty robust and defendable even when the effects of the simplifications that have been made are taken into account. The estimated effects varied considerably over the year.

Acknowledgements

I am grateful to my supervisor Eirik Gaard Kristiansen for being available and interested during the process. He has been able to help me put things in perspective and push the process forward. The power market is a very complex market and simplifications have been necessary at several points in time.

Arndt von Schemde at THEMA consulting has been kind enough to provide me with helpful feedback. His insights have been very useful, and I am very grateful that he took the time to be my sparring partner in discussing some of the approaches used in this thesis. Many of the approaches used in this thesis are built mostly on my own observations since the approach chosen here has not been applied previously, at least not to my knowledge. The possibility to have discussion with such a knowledgeable person has been invaluable and absolutely necessary.

This thesis would not have been possible were it not for the great transparency and availability of data material at the Nord Pool power exchange. Kristina Remec, service manager at Power data services at Nord Pool has answered numerous questions and she has been helpful with providing any data that has not been available on the web pages. Without her the completion of this thesis would be much more difficult.

In addition I am grateful to Vlad Kaltenieks at APX endex for providing me with data for the Dutch market. Polish and German power prices are publicly available at the relevant power exchanges.

Matias Krogh Boge

Abstract

One new 1 400MW cable connecting the south of Norway to Germany is planned and modelled in this thesis. Combined with the new SK4 cable connecting Norway with Denmark, this will make the south of Norway an important transit area for trade of short-term flexibility of hydropower against the long-term security of supply that thermal power from the continent can supply. Increased implementation of new renewable and intermittent energy both in Norway and the trading partners will create large local surpluses of energy in periods; this increases the need for trade and the strengthening of transmission networks. In addition a cable connecting the south of Norway to the UK is planned. This is not included in the analysis since relevant UK prices have not been available for the entire year.

The planned installation of new cables is likely to increase security of supply and also better the utilisation of production technologies in the affected markets. The effect of the cables will depend much on the hydrological conditions in Norway and Sweden. For that reason I have chosen to use 2011 as a base year for my analysis. 2011 started out with a cold winter and shortage of supply due to a dry previous season and low hydro reservoir levels, and it ended with a wet summer and fall as well as a mild winter with high reservoir levels. Modelling over this year we will be able to look at results for both a Nordic surplus and deficit situation.

Many fear that more interconnectors to the continent will lead us to import continental price structures and levels to the Nordic market. How prices and traded volumes will depend on the amount of trade capacity between the Nordic market and its neighbouring markets is what I will be trying to model in this thesis. I have built a model coupling the Nordic with its adjacent markets, and based on historical supply and demand data I have estimated changes in prices and volumes as a result of the proposed new trade capacities. The focus is on the Nordic market and I will try to estimate the degree to which new cables will import continental price levels and price structures.

I hope this thesis will be of interest to policy makers and others wanting to better understand the workings of the modern Nordic electricity market and the challenges and opportunities that trade brings to it. Contrasted to other research this thesis focuses on the power market as it presents itself in the market place at Nord Pool. I believe the analysis is easier to follow than the fundamental approach since the discussion will rely on easy to understand transparent analysis as the number of inputs to the model are considerably fewer than what is needed for a fundamental approach. Hopefully the reader will be able to follow the logic and reason used when results are presented, and not simply be fed with complex outputs from a model. We will also be able to look closer at interesting points in time over the year.

Relying on fewer inputs however, the model becomes unsuited for modelling quantitatively large changes in the power market as we rely solely on historical data. The model is as such unsuited for a quantitative scenario analysis on long time horizon, as has been the norm in similar research. Some of the lessons learned from the conclusions drawn in this thesis may on the other hand be used to discuss qualitatively what is likely to happen in the future as fundamental factors change. The model does rely on a series of simplifications, which will be discussed after the model results themselves have been presented.

Introduction

The first part of this thesis is an introduction to the Nordic power market and the Nord Pool trading platform as well as the recently separated financial market, now part of the Nasdaq OMX commodities platform. First the Nord Pool market place is presented and an explanation of the price formation procedure is explained, then the financial market is briefly presented. Further the physical aspects of the Nordic market is presented and contrasted with the nature of the adjacent markets. On this background the shape of the supply and demand curves are discussed. The understanding of these will be essential to follow the discussion in the rest of the thesis.

The second part consists of a brief discussion of how trade creates value in the electricity market.

Part three introduces the main model applied in this thesis.

Part four presents the results from this model. The results are discussed in light of the simplifications made and how these are likely to bias the results. The results discussed are the changes in price structure and price level.

In the last part I offer my conclusions on the effects of increased trad had in the model. I point to some of the major weaknesses of the methodology applied and how they are likely to affect results

1. PART I

1.1 Introduction to the Nordic power market and Nord Pool spot

In this thesis the term the Nordic market and the Nord Pool market will sometimes be used interchangeably. In reality the Nord Pool market place also includes Lithuania and Estonia. In 2011 however, which is the year used in this analysis, only Estonia was part of the market place. Estonian volumes were very modest, but they are part of the system price curves used in this thesis. Iceland is not part of the Nordic Power market. The Nordic power grid is connected to the German, the Polish, the Dutch and the Russian market. The Russian market will be completely ignored in this thesis since it is not handled through Nord Pool, trade is not liberalized in Russia and the trade is handled through OTC deals which makes it difficult to include in the model. Data are not easy to find either. Trade with the other countries are handled through Nord Pool. In 2011 approximately 75 percent of Nordic electricity was traded through this platform, the rest was handled through OTC trading[1].

The Nordic power market has during the last decades gone through some major changes. It has gone from being four nationally regulated markets to becoming the first international market for trade of electricity. Today electricity prices in the Nordics are a reflection of deregulated supply and demand. Only transmission of electricity remains a regulated, natural monopoly.

The deregulation of the electricity market has largely been regarded a success, and today there exists both a physical market for trade, the Nord Pool spot marked, and a financial market, the Nasdaq OMX commodities market. In addition there exists a regulating marked

[1] Based on own calculations where I have used data material provided by Nord Pool on total Nordic production, net trade and volume traded on Nord Pool. The figure varies somewhat over the year. See graph 10

and another spot market for physical trade, the elbas market (both part of the Nord Pool trading platform).

The trade of electricity differs from most, if not all, other types of commodity trade. This is mainly due to one aspect of the trade; for every point in time there has to be perfect balance between supply and demand. Electricity cannot be stored economically in large quantities, for this reason electricity delivered has to equal electricity demanded at all times. Electricity delivered at 12:00 is not the same commodity as electricity delivered at 01:00. This makes electricity prices extremely volatile since they are almost completely disconnected even over short time intervals.

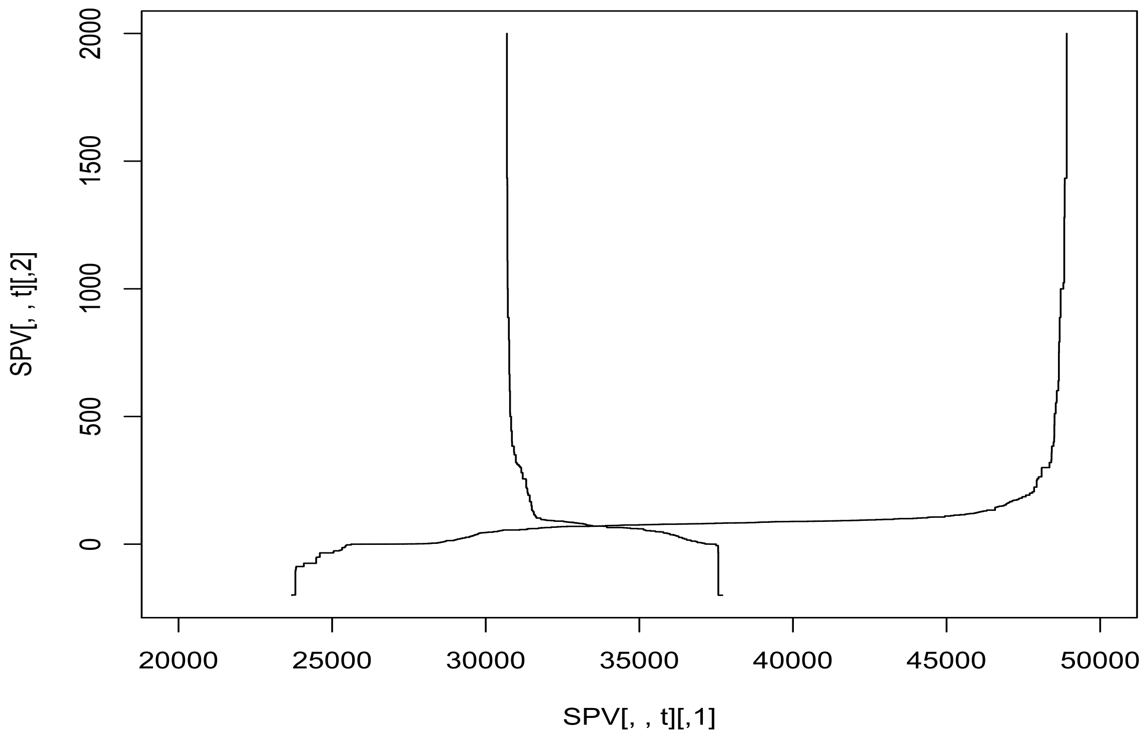
1.1.1 The day-ahead spot market

Because of the strict law of equality between supply and demand at all times, the price does not work fast enough to make the market clear at all instants of time. Therefore the trade of electricity has to be planned in advance. This is what the day a head spot market does. Agents place supply and demand bids for a given quantity of power, at a given price and for a given hour. The spot market consists of hourly contracts. In addition to this it is possible to place block bids, both on the supply and the demand side. Block bids are bids covering more than one hour. They are posted at a given price and will be rejected or accepted in their entirety based on the posted price relative to the average price for the relevant hours. According to Nord Pool there seems to be no logical market solution when market prices have to be calculated for any given hour and block bids are included, the inclusion of block bids is therefore based on a pragmatic approach[2]. We will however abstract from this rather complicated aspect of the market place. The interested reader can read more on the complicated nature on the Nord Pool home page. This far we note that the block volumes are quite small making up approximately 5% of traded volume[3].

[2] See the Nord Pool homepage on the day-ahead-market and block bids.

[3] This number varies considerably, see discussion regarding model simplifications later

Maximum price in the market place is 2000€/MWh and the minimum is -200€/MWh. At Nord Pool all bids for the day ahead spot market have to be placed before 12:00 the day prior to delivery. Prices are posted between 12:30 and 12:45. Physical delivery of the contracts start at 00:00.



Graph 1 Example of bid and ask curves for a given hour, prices in Euro, volumes in MWh.

Before prices are posted however two things complicate matters somewhat. The Nordic market is coupled with other markets and even the Nordic market is in practice only a single market about 26% of the time.

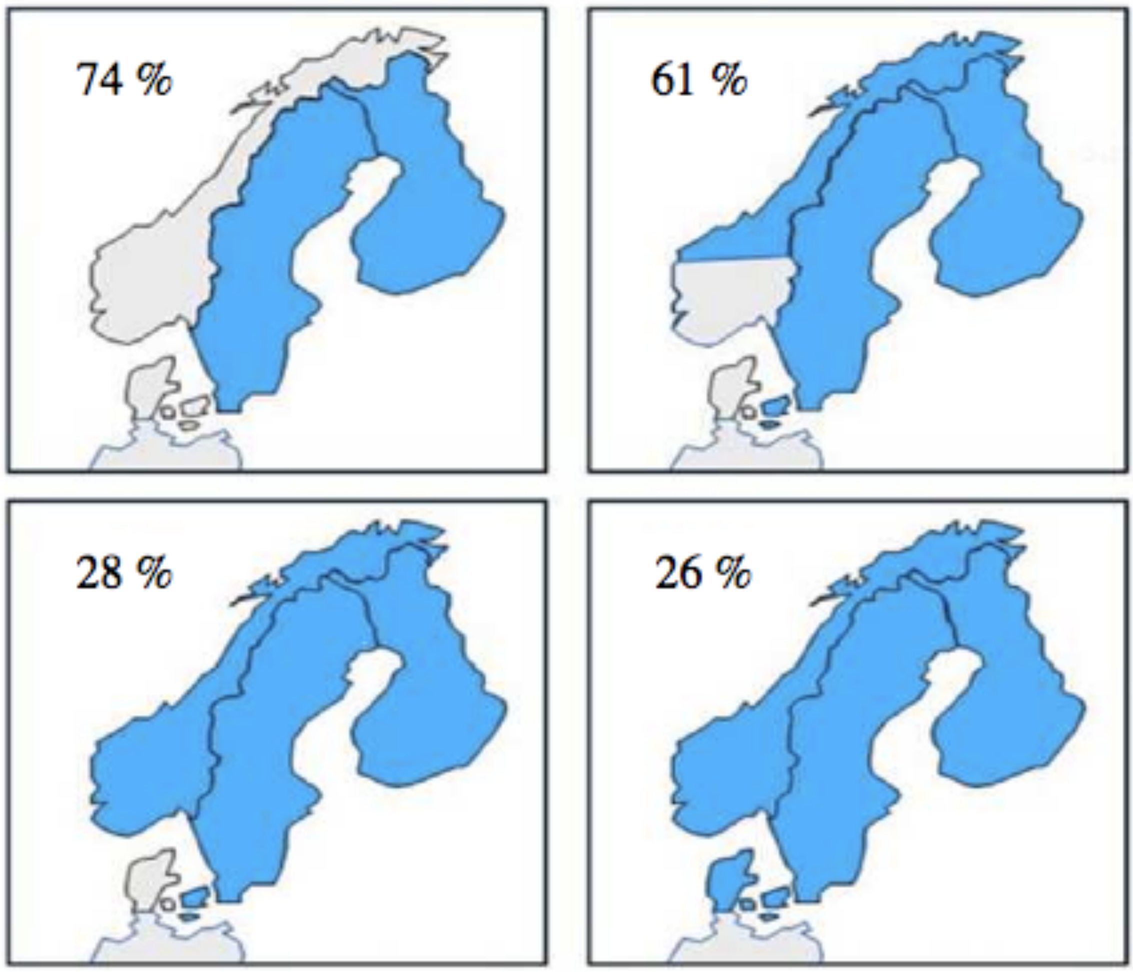


Illustration 1: Shares of the annual hours the different areas have shared the same price in 2011. (source: Nordic Energy Regulators, Nordic market report 2012, report 3/2012).

The European Market Coupling Company, the EMCC, handles the first part of the problem. They receive bid and ask data from all relevant markets and based on these they calculate the optimal flow of power between the different markets[4]. Based on these optimal flows they place bids that are added to the original market clearing algorithms of the respective markets. Nord Pool is now able to calculate the system price, that is the price that would clear the market if there were no constraints within it. This is the price formed at the intersection of the curves presented in graph 1 after the optimal trade is added to the picture.

[4] See EMCC home page, http://www.marketcoupling.com/

The other problem is related to the fact that electricity does not flow freely through the air. The flow of power between different geographical areas within the Nordic market is not unlimited. Often power is not able to flow from surplus areas to deficit areas to such an extent that the prices calculated as the system price is feasible in all areas. This is solved by creating price areas are at places where there are constraints in the system. This is done in order to clear the market within these different areas. Within Nord Pool several price areas are constructed where bottlenecks often occur.

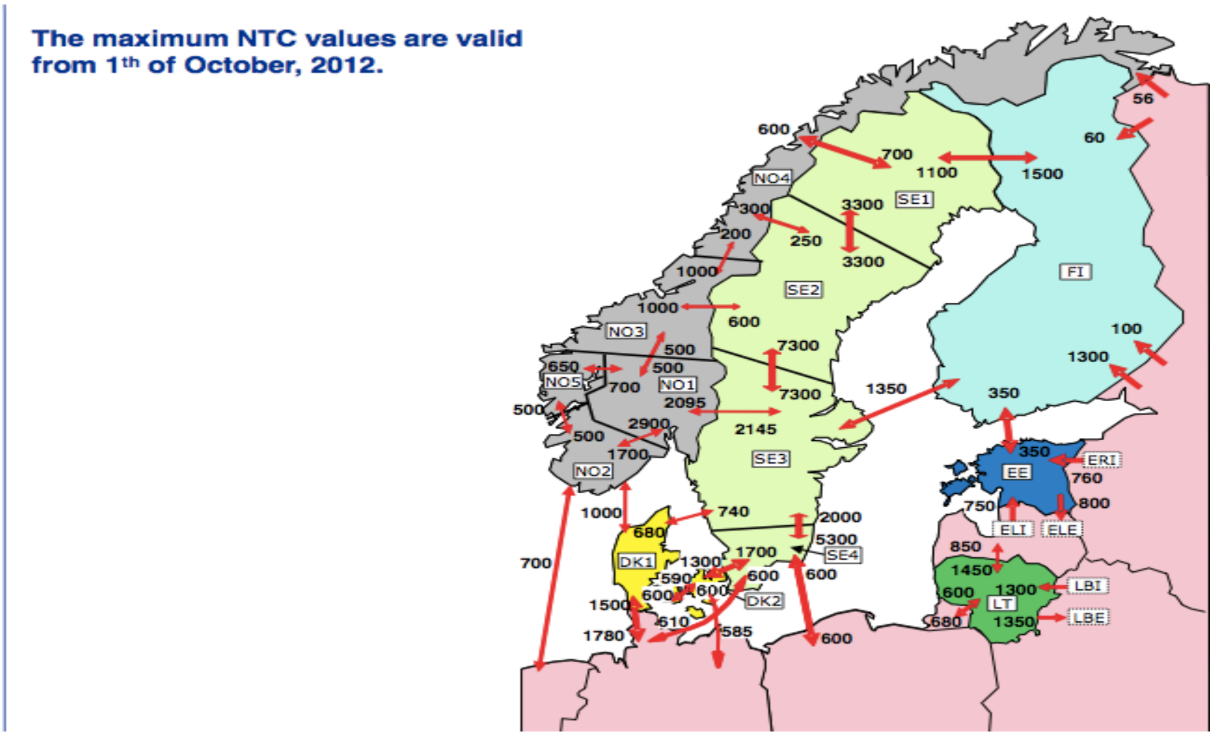


Illustration 2: Current price areas at Nord Pool and net transfer capacities between areas. Sweden was up until 01.11.11 one price area. Lithuania was not part of Nord Pool in 2011 (source: Nord Pool homepage)

These price areas are however still artificial. Price areas have to be defined, and there is often a trade-off between the size of and the number of price zones and economic efficiency. We can think of the degree of area pricing like this: On the one extreme side an entire market place always has the same price, on the other extreme there exists a different price for electricity at every node of the transmission grid. In between we go from one price area up until we have a zone for every node in the network.

Price areas (as opposed to nodal pricing) are inefficient because they by nature are artificial and they can create suboptimal use of resources due to their simplified portrayal of reality (see Pettersen et. al, Mapping of selected markets with Nodal pricing or similar systems, NVE report 2/2012, see also NordReg, Congestion Management in the Nordic Region-A common regulatory opinion on congestion management, Report 2/2007).

Sweden was up until recently one large price area. That meant that Sweden had one price, no matter how demand and supply was divided geographically (See Sadowska & Willems 2012 on how a complaint filed by Dansk Energi led to the division of Sweden into four price areas).

To keep prices equal within a price area producers in surplus areas (within the price area) sometimes have to cut back on production even though some consumers want to buy power at a price higher than suppliers will charge for that power. In deficit areas the case is the opposite. Here, either producers have to increase production to a level at which costs are higher than the market price, or consumers have to reduce their consumption to a level lower than they themselves would deem optimal. Consumers and producers will not do this without some sort of compensation. For producers to increase or decrease production relative to what they would optimally do at the prevailing area price, they have to receive some sort of compensation. The same goes for consumers, they to must receive some sort of compensation to adjust their behaviour relative to what they otherwise would deem optimal. This is in fact what TSOs do, and it is called counter purchasing or counter trading (see Nordic Energy Regulators, Congestion management in the Nordic region-A common regulatory opinion on congestion management, Report 2/2007). Contrary to having bottlenecks between price areas, which create revenue to the grid owners and are a reflection of economic reality, counter purchases are costly and constitute a distortion from real economic constraints.

Nodal pricing is the most efficient pricing scheme because it takes into consideration all of the limitations of the grid system when pricing electricity. A nodal pricing system is however much more complicated and the functionality and liquidity of both the physical and the financial market would be threatened. The fever the bottlenecks within a price area, the smaller however are the losses in efficiencies likely to be due to the abstraction from nodal pricing. A price area does not account for the fact that losses in transmission will vary at different nodes in the system; this also makes it less efficient. This inefficiency is tied to the quality of the transmission network and the distances between supply and demand. A more detailed discussion of zones vs nodes is not relevant to this thesis and I refer the interested reader to the mentioned NVE report or the report by Nordic Energy Regulators.

It is however important, in order to understand the complexity of transfer capacities between prices areas, to understand the nature of a price area and the simplified picture of reality that it portrays. It is not simply a pool of power supply and demand and inner constraints can, and often will, affect outer constraints. This was especially true before Sweden was divided up into four price areas.

Looking closer at the Swedish case we can use it to illustrate the link between inner and outer constraints. In January 2011 the Swedish-Danish lines were congested because of congestion in the intra-Swedish grid, more precisely the part called the southeast corridor. Prices in Sweden were much higher than prices in Denmark; still the transmission lines on the border were far from utilized to the full. The reason for this was that transmission lines going from south to the north were constrained and in order to maintain Sweden as one price area, Swedish TSOs had to reduce imports from Denmark. (The opposite case when prices in Sweden were low and exports to Denmark were constrained led to the mentioned Danish complaint) If not prices would fall in the south and it would be very expensive to lower prices accordingly in the north since this would have to be done by counter purchasing. Imports from Poland and Germany where also reduced because of these inner bottlenecks.

In order to maintain established price areas it can be necessary to reduce cross border capacities when inner area constraints occur. It can also be economically efficient as opposed to using counter-purchasing tactics within the price area, see discussion by Sadowska & Willems 2012.

Hopefully we have now established a sufficient understanding of the price formation and functioning of the Nordic power spot market. Prices are calculated based on supply and demand bids placed by different actors on an hourly basis. In addition to these bids come the demand/supply bids calculated by the EMCC. Nord Pool can apply their market-clearing algorithm to the supply and demand bids, and calculate the system price. The system price is the price that would clear the market if there were no inner constraints. After the system price has been calculated inner constraints are taken into consideration and market-clearing prices for the pre-defined price areas are calculated based on constraints signalled by the TSOs.

In addition to the elspot market Nord Pool handles, two other physical markets for power, which will be briefly presented.

1.1.2 The balancing market

Most of the consumption of electricity is done by consumers purchasing electricity through utility companies. These utilities buy given quantities in the spot market based on estimations of the demand from their customers. Obviously it is not possible to have 100% of precision in estimates. For that reason demand will deviate somewhat from the planned demand for a given hour. Supply is not necessarily exactly as planned either, this is easy to see if we consider sources of supply such as wind power. Production will typically not be exactly equal to the predicted production. This means that some actors must be able to quickly adjust their demand or supply when the balance is failing due to deviations from planned production and or demand. This can be done by changing either supply and/or demand in the direction needed to restore balance. Actors on both the supply and the demand side therefore offer capacity to the balancing market. This allows the balancing to be done in a cost efficient way since the cheapest sources of adjustment will be called upon first.

The balancing market is divided into three separate markets based on the speed at which the reserves have to be activated (Wangensteen 2012 p 278, Statnett home page). The primary market consists of power reserves that have to be able to be activated immediately. This reserve is activated automatically when imbalances occur. The secondary source of reserve is activated manually and has a slightly longer response time. The tertiary market is operated at Nord Pool and has a manual response time of 15 minutes (Wangensteen 2012 p 278). Actors place bids for up and down adjustment based on free capacity. The first two markets are handled through agreements between the national TSO´s and producers where compensation is offered to keep spare capacity.

Any remaining generating capacity that is not sold and that can be started fast enough is put in the tertiary market. In addition come reserves are kept additionally as spare capacity and never offered to the spot market.

The balance market is fairly complicated and the interested reader can read more on this on the pages of Statnett or the other Nordic TSOs or Wangesteen 2012 pp 276-308. A deeper understanding than the one presented so far is not necessary to follow the logic and methods applied here and it falls outside the scope of this thesis.

1.1.3 The elbas market

The reason for the day ahead spot market is, as already explained, to plan production and price formation in advance. Since bids have to be placed before 12:00 the day prior to delivery this leaves a gap between the placing of the bid and delivery for the last hour the next day of 35 hours. The elbas market is there so that any remaining capacity can be traded up until the last hour before delivery. Things can change in these hours especially for intermittent power sources such as wind power. Trading in the elbas market will reduce some of the strain on the balancing market. Volumes are insignificant compared to the day ahead spot market, which sets the reference price. The elbas market is not of further relevance to this thesis.

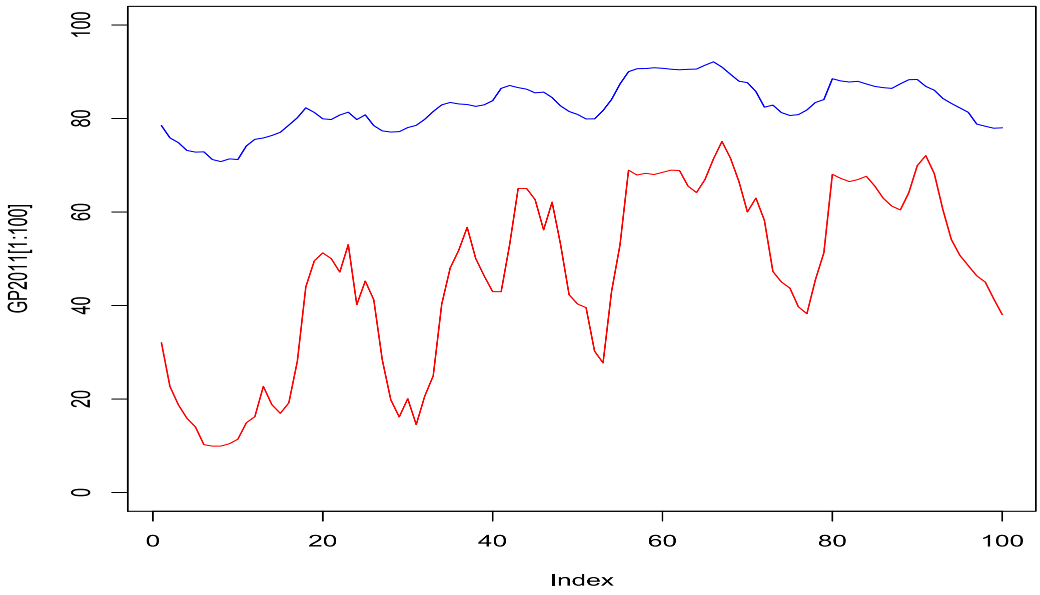
1.1.4 The financial market

The financial market was recently moved from the Nord Pool platform over to Nasdaq OMX commodities. Trade of financial contracts connected to the products traded in the Nord Pool market place are handled here and the system price is the reference price for most of these products. The trade of financial products is far greater in volume than that of the physical market, and an increasingly rich menu of tradable contracts is available. This allows actors in the physical market to hedge the risk associated with fluctuating electricity prices. The market efficiency is estimated to be quite good (see Hoff 2010 on price), I will not go further into these details; the interested reader can visit the home page of Nasdaq OMX commodities to read more about available products. I will however mention that all of them are divided into base- or peak-load contracts. The shortest contract is for one day where base-load refers to the entire day while peak-load is 08:00-20:00. Some contracts are traded up to six years into the future.

The relevance of the financial market to this thesis is that there exists an arena where actors might hedge their price risk, something that is relevant to their behaviour in the spot marked.

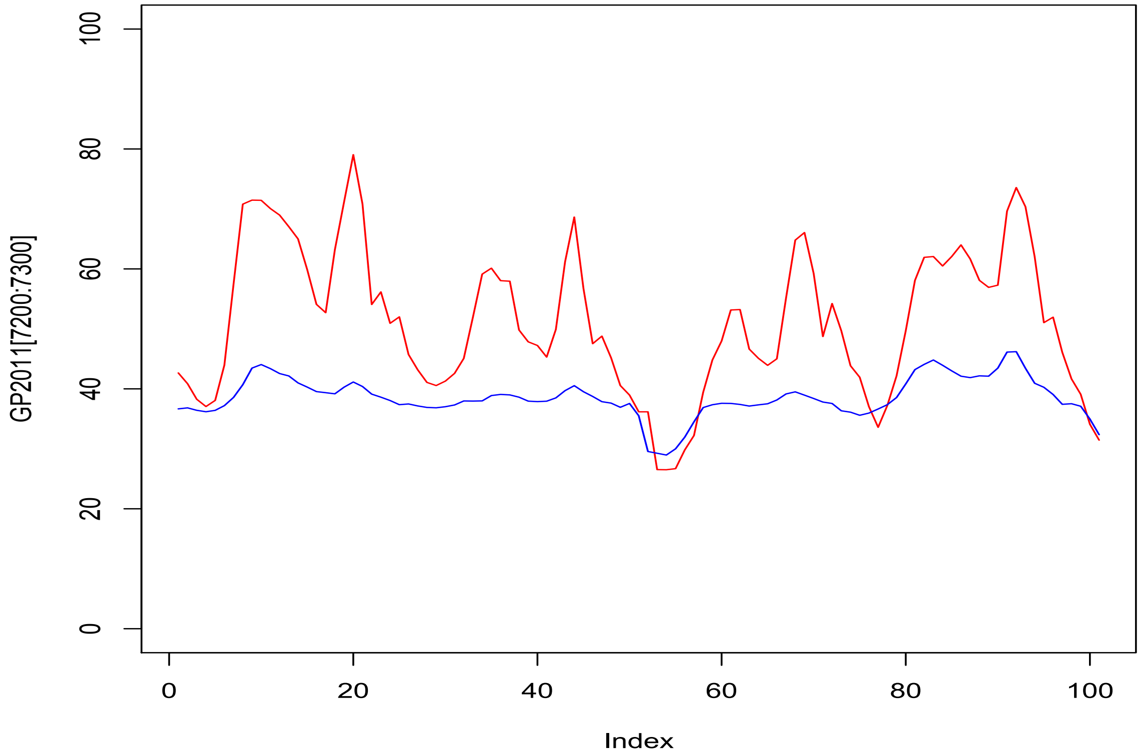
1.1.5 The physical nature of the Nordic market

The Nordic market differs in an important way from many other electricity markets due to the dominant role of hydropower. Although electricity cannot be stored, water can and this makes the Nordic system much more flexible on the supply side, at least in the short run, compared to most other markets for electricity. The price structure in the Nordic market is therefore much flatter on an hourly basis than other non-hydro dominated markets.



Graph 2: Nordic price (blue) vs. German price (red) dry period (sources Nord Pool and EEX, European power Exchange)

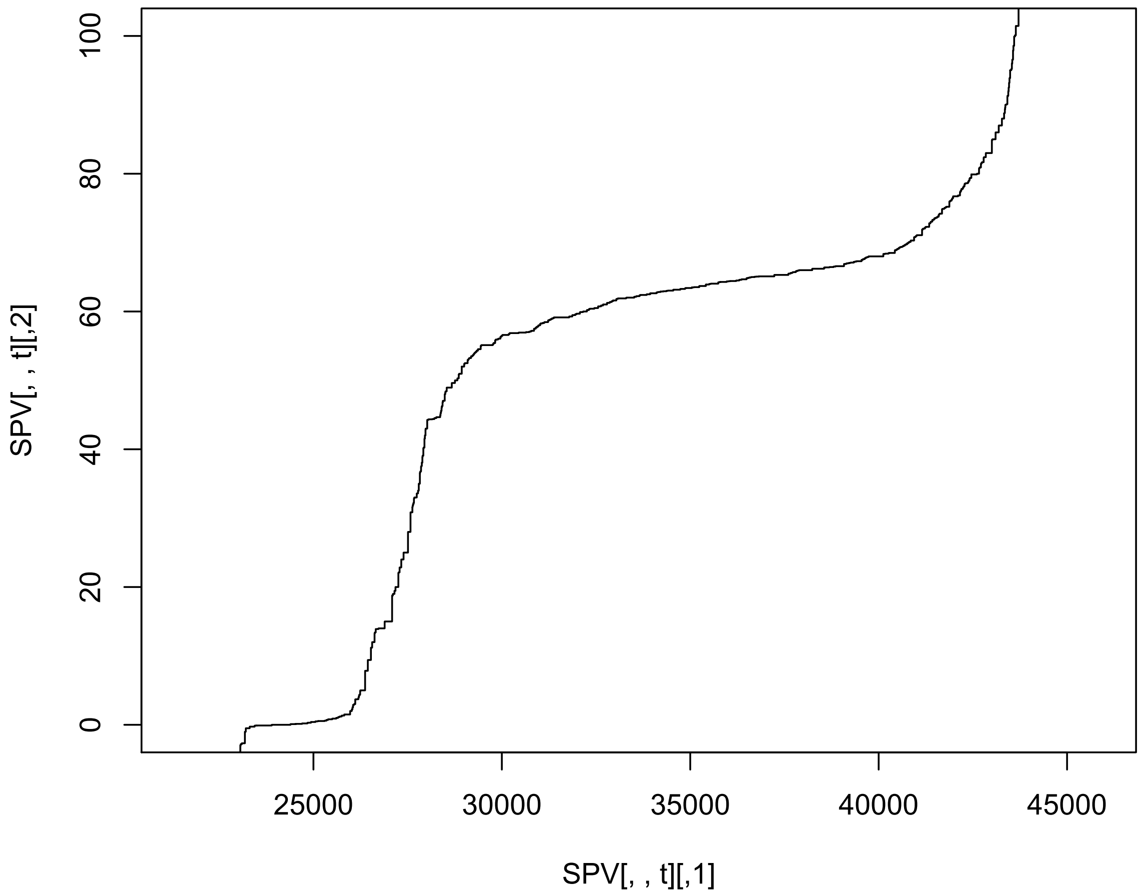
The graph (above) depicts the Nordic system price (blue line) and the German system price (red line) for the first hundred hours of 2011 in €/MWh. Two things are evident; the Nordic curve is relatively flat while the German is much more volatile and the Nordic price lies well above the German. This can be contrasted with the price structure in October the same year:



Graph 3: Nordic price(blue) vs German price in wet period

A wet summer and fall made Nordic electricity cheap due to high reservoir levels and high hydro production. The price level is approximately halved. The German price level is more stable even though we have a price structure that is much more volatile by the hour.

The reason for these very different patterns is the fact that hydropower can adjust production almost costlessly in the short run while it in the long run is limited by the rainfall and levels of the reservoirs. A coal plant, and to an even greater extent a nuclear plant, cannot adjust production much on an hourly basis. In the long run however it is possible. When demand shifts a lot during a day while supply lacks the ability to do so, we have large price differences over a day. The hydro producers however will adjust production so that they produce when prices are high and hold back when prices are low, this will even out the price differences in the short run. This is reflected in the relatively flat structure of the supply curve around the price level.



Graph 4: Supply curve for the Nordic market. Price in Euros on the vertical axis, volume in MWh on the horizontal. Relevant price level 65€/MWh.

In the long run, hydro producers are limited by reservoir levels and expected inflow to reservoirs. This is why prices in the Nordics fluctuate much on a seasonal and yearly basis. While coal producers can buy more coal, hydro producers cannot buy more rain or save up infinite reserves in their reservoirs. The average price level in markets dominated by thermal production is therefore more stable in the long run (measured in average price level).

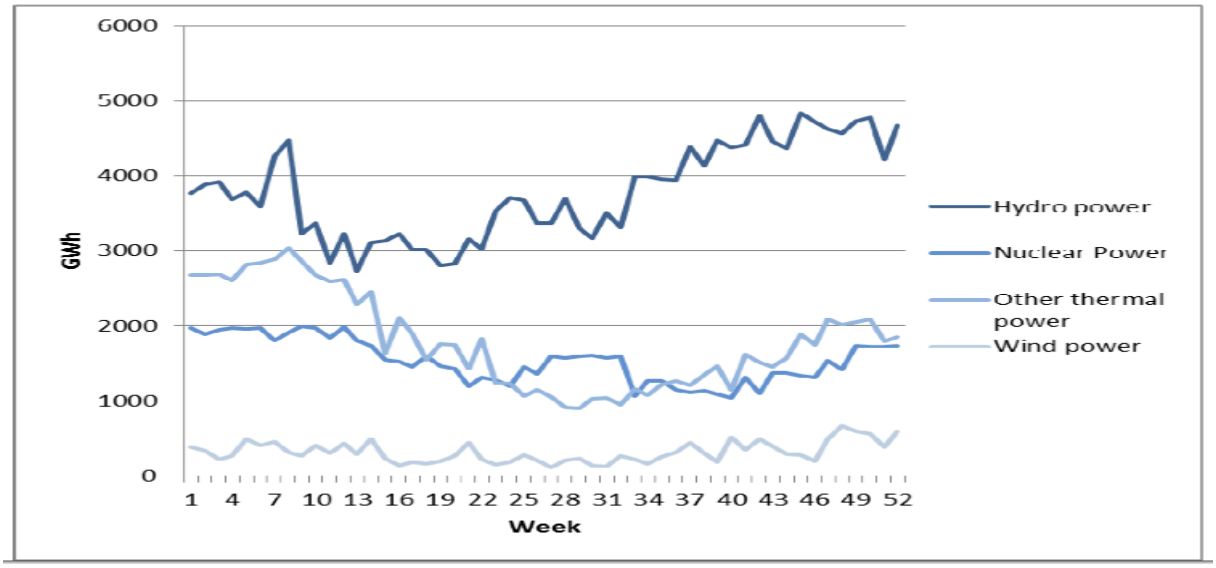
Nordic generating capacity in 2011 was as follows:

	Denmark	Finland	Norway	Sweden	Nordic region
Installed capacity (total)	13 540	16 713	31 714	36 447	98 414
Nuclear power	-	2 716	-	9 363	12 079
Other thermal power	9 582	10 651	1 062	7 988	29 283
- Condensing power	1 590	2 155	-	1 623	5 368
- CHP, district heating	7 118	4 300	-	3 551	14 969
- CHP, industry	674	3 362	-	1 240	5 276
- Gas turbines etc.	200	834	-	1 574	2 608
Hydro power	9	3 149	30 140	16 197	49 495
Wind power	3 949	197	512	2 899	7 557

Illustration 3: source: Nordic Energy Regulators, Nordic market report 2012, report 3/2012

We can see that hydropower is the dominant source of generating capacity. Production technologies within each country also vary a lot with Denmark being totally dependant on thermal and wind power while Norway is almost exclusively dependent on hydropower.

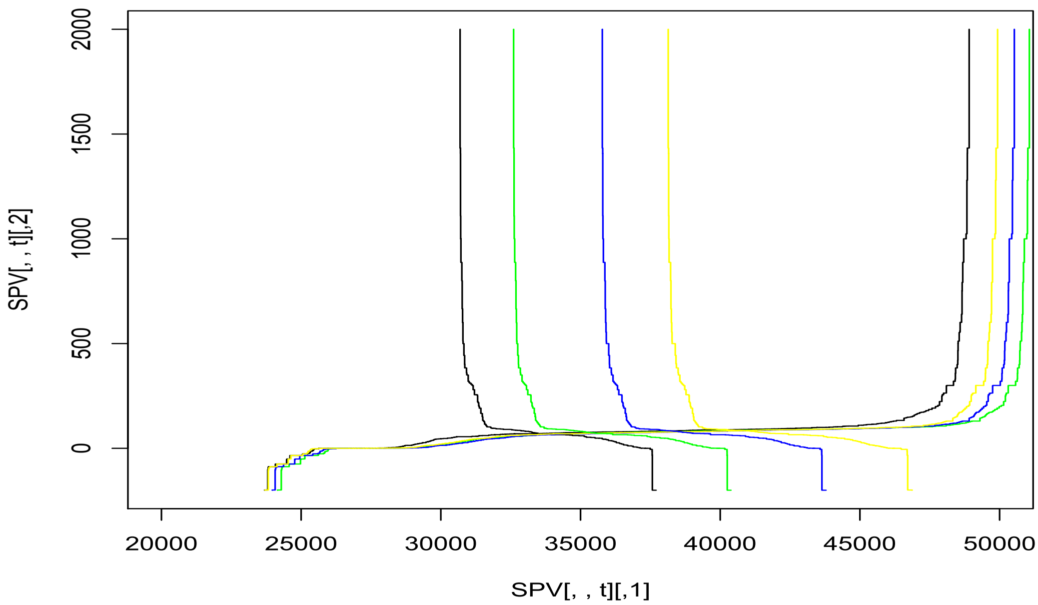
It is however important to distinguish between generating capacity and production. Generating capacity is not necessarily proportionate to actual production when looking at different production technologies. Typically it is not. Different production technologies will have very different capacity factors; the capacity factor will also vary considerably among production facilities belonging to the same group. Capacity factor is defined as actual production divided by capacity times time interval. To exemplify: Wind production capacity in Sweden was 2 899MW. In one year 2 899MW of capacity operating 100% of the time would yield 2 899MW*8 760hours=25 395 240MWh ≈ 25TWh. Actual Swedish wind power production in 2011 was ≈6TWh. This gives a capacity factor of 6/25=24%. Total hydro production was ≈200TWh. Capacity*hours=8760*49 495≈434TWh. Capacity factor = 200/434≈46%. Nuclear has the highest capacity factor of 75,5% while thermal other than nuclear was around 30%. It is worthwhile to mention that “thermal production other than nuclear” is a fairly diverse group. Production stemming from different sources on a weekly resolution looked like this in 2011:



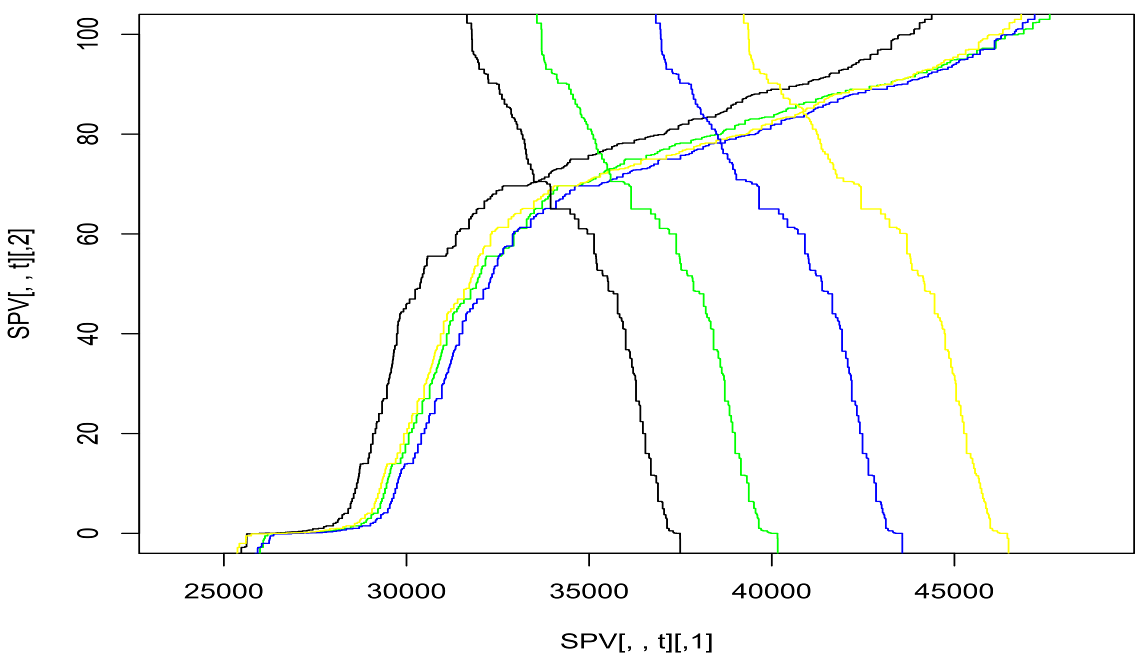
Graph 5: Source: Nordic Energy Regulators, report 2012

1.2 System price curves

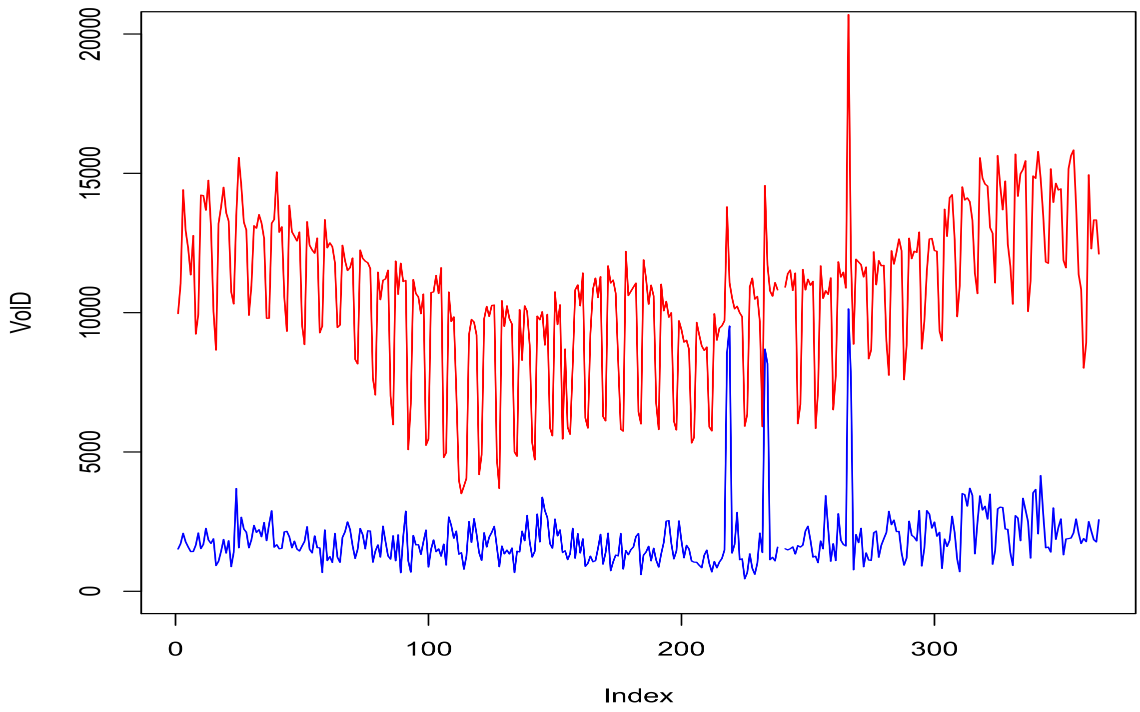
For the spot auctions anonymous bid and ask data are posted on the Nord Pool home page. By inspecting the curves that can be produced from these data sets we can learn much about price formation and the basis on which the main model of this thesis is built.



Graph 6: Supply and demand for hours 5(black),9(green),14(blue) and 20 (yellow) 1. January 2011



Graph 7: Same curves for the more relevant price interval. System price never moved outside this interval during 2011



Graph 8: Daily volatility in supply (blue) and demand (red) measured as maximum distance between curves within a day. We se that average daily volatility is approximately 6 times higher for demand than supply on average. (1 700MW vs 10 000MW). The three extreme spikes seen should be ignored as they are the result of an inconsistency in the Nord Pool data material. Volatility is much lower in weekends than on weekdays for demand, this is the oscillation that we see in the red curve.

1.2.1 The supply curve

The characteristic form and placement of the supply curve does not change much during a day. We can however observe some shifts in the curve. This is likely to be due to changes in wind production, accepted block bids and some minor changes in behaviour between peak and base load hours (the black line is a base load hour, the others are peak load). Some producers are likely to only sell their production during peak-load for instance. We also notice that approximately half of the amount supplied are placed at the lowest possible price at the Nord Pool market place, -200€, something that might seem strange. Looking closer at the decision that a thermal producer is faced with it soon becomes easier to understand.

Thermal production including nuclear makes up slightly less than 50% of Nordic power production, with variations depending on the time of the year and whether we have had a wet or a dry season. Thermal producers, in general, do not sell power by the hour. It is very costly to shut down operations and to start them up again. For this reason thermal producers will be very reluctant to reduce supply in response to prices by the hour. What is of interest to them is the average price over a given period of time. If the average price is high enough they will produce, if not they will not produce. Their behaviour when looking at it on an hourly resolution will therefore give an incomplete picture. The hourly spot market does not reflect their marginal costs or willingness to produce. Thermal producers can secure their average price in the financial market and simply put their production in the spot market. No matter what the hourly price becomes they will have secured an average price for their production and will not adjust at all to the spot market in the very short run that the curves reflect. This is why thermal producers will offer their production even at negative prices if they prevail only for a short period of time. This is because it is likely to be costlier to shut down and start up than receiving a negative price for the quantity produced during a few short hours. If they had placed their bids at higher prices they would risk not being able to deliver the power and they would be forced to make a costly shut down and start up.

Therefore bids placed at positive prices are likely to consist mainly of hydropower. They would not want to use the financial market to secure prices. They have practically no cost attached to rapidly changing their production and can at any time take advantage of a fluctuating price. Binding the price would be giving away a free option.

Understanding the behaviour of the hydro producers is much more difficult than understanding the behaviour of the thermal producers. Contrasted to production from coal, hydro production has very low, close to cero marginal cost. On the other hand water is a limited resource and if you use it today you have less to use in the future. Coal you can always buy more of, at least for a couple of hundred years to come. When hydro producers decide at what price to offer production, it is a complex decision depending on expected prices and price structures in the future, current reservoir levels, expected inflow to reservoirs, the shape of the reservoir and installed capacity. Hydro producers want to sell as much as possible when prices are high and as little as possible when prices are low. If all hydro producers where faced with the same expectations, limitations and perfect foresight we would most likely have close to a straight line of bids at the expected alternative value of water. This is not exactly what we see; the supply curve is however relatively flat around the expected average price level.

The fact that it is not flat is a reflection of the heterogeneity of hydro producers. First lets start with difference in installed capacity relative to average production. Lets say that expected production for the relevant planning horizon is 100MWh and the relevant planning horizon is 100 hours. Then average production rate is 1MW. With a capacity of 2MW capacity factor is 50%. This means that in order to produce the necessary amount over the planning horizon (for instance to avoid overflow of reservoir) the producer has to produce at least 50% of the time. The producers would achieve the highest possible profit by producing when prices were above average and shutting down completely when below. If the capacity factor were higher (lower installed capacity) the producers would have to produce more than 50% of the time and hence put up bids at lower prices than they would have to with lower capacity factor (higher installed capacity). The opposite is true for a producer with low capacity factor.

In addition inflow to reservoirs will be different for different reservoirs. The reservoirs are also of different size, which will give them different planning horizons; in addition they are probably at different levels. Located at different geographical locations expected prices and price structures may also be different.

Another factor is that turbines work at different efficiencies for different use of capacity. Generation efficiency is not exactly the same for a generator running at 100% as at 80% (Wangesteen 2012, p290). Typically efficiency is highest at around 80%. The remaining 20% is also a good source of balancing power (Ibid). In addition it is not irrelevant what level the reservoir is at. The “head” as it is called will be lower when reservoirs are lower.

The “head” is the difference in water level contrasted to the generator. The potential energy of water can be described by the simple formula m*g*h (m=mass, g=gravity, h=height). When the reservoir level is higher the water level will be higher and the speed of the water will be higher when it reaches the turbines, which means that more energy is converted to electricity per mass of water since $E=1/2mv^2$ and v^2 is proportionate to g*h (v=velocity). In theory $1/2mv^2 = m*g*h$, some energy will be lost due to friction however on the way from the reservoir to the turbines. Depending on the shape of the reservoir the reduction of head from production will be different. A deep reservoir will be more affected than a shallow reservoir of the same size since the head will be reduced faster in the deep reservoir. Producing from a full reservoir gives more energy per unit of water than producing from a less than full reservoir everything else equal. Actual capacity of a hydro producer is thus not only dependent on the installed generators but also on the reservoir level. Electricity per litre of water will also be dependent on the level of the reservoir.

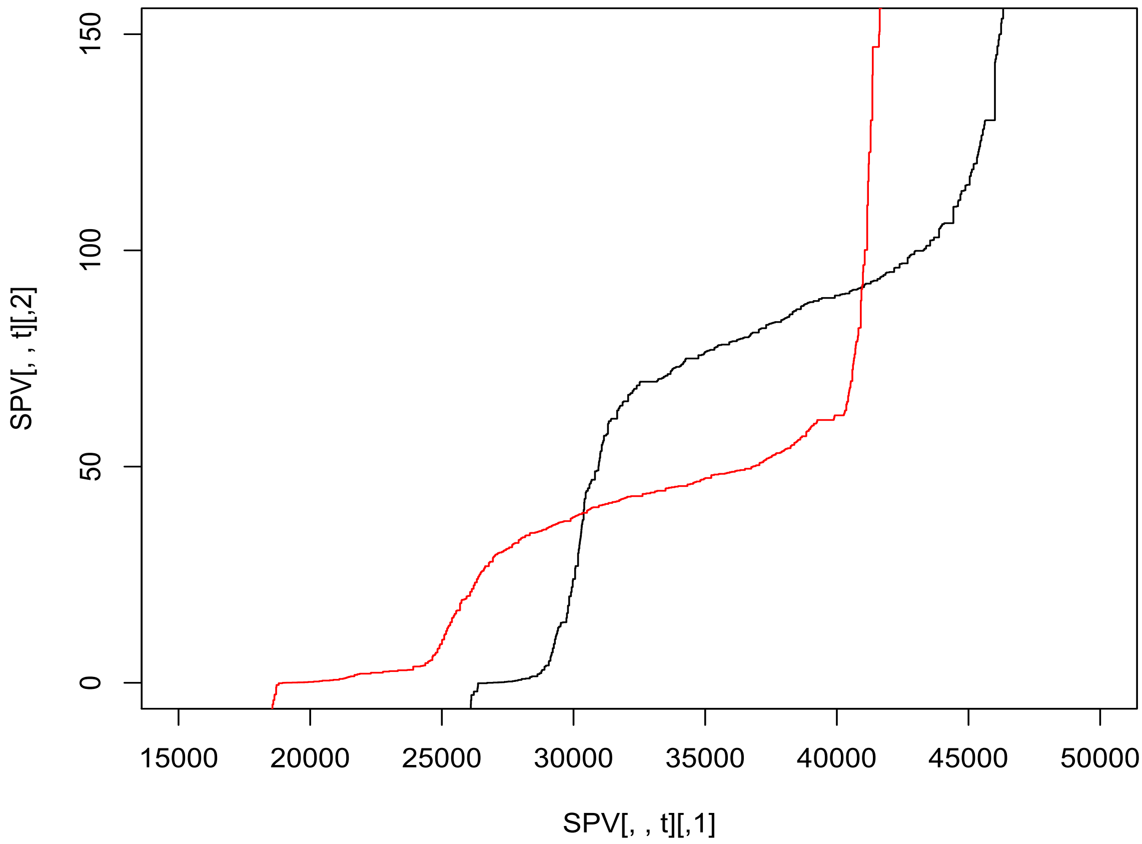
In addition to all these factors, two otherwise equal producers need not have the same expectations for the future nor have the same attitudes towards risk; this would also lead to different evaluations on the alternative value of water and result in different behaviour in the spot market.

The point however is not to give a perfect description of the complex decision that hydro producers are faced with. It is rather to provide an understanding of the complex nature of the decision problem that the hydro producers face and how their aggregate behaviour is reflected in the shape of the supply curve. This will be relevant when discussing the effects that trade is likely to have on the market later.

To complete the picture some of the marginal bids will also be from thermal production. Volumes are probably not very big however as an example from the first week of January 2011 might illustrate. The example also supports the understanding of the supply curve as it is presented so far. In this week 4.4 TWh (source Nord Pool) worth of thermal electricity was produced equalling an average rate of production of 4.4TWh/(7*24h)≈0.0262TW=26

200MW. As we can see from the supply curves above, almost all thermal production is accounted for in the inelastic part of the curve where prices are below cero (the supply curve crosses the cero price line at approximately 26 000MW).

All in all the supply curve is pretty fixed in the short run as the factors discussed so far will not change dramatically over short time intervals. Changes in thermal production will shift the curve horizontally, while factors that will affect the alternative value of water will move the curve up or down (the part above cero) depending on sign of the expected effect. Due to the non-homogenous effect on hydro producers the shift will not be perfectly parallel however as changing fundamentals will affect hydro producers disproportionately. In addition changes in wind and other intermittent production as well as some peak load power production from gas-powered plants will add some noise to the picture.



Graph 9: Supply curve winter(black) and summer(red)

From the graph we see that the summer curve has changed relative to the winter curve by moving downwards and to the left. The movement to the left is because thermal production has gone down due to lower average prices and less need for heat production (CHP, Combined Heat and Power, production is reduced). The alternative value of water has also gone down as reservoirs are close to full forcing hydro producers to produce at a higher rate; this moves the supply curve downwards. The flat part of the supply curve close to cero has also increased. This is not due to increased wind production, which typically is higher during winter. A plausible explanation might be that full reservoirs are forcing some hydro producers to sell the water at any positive price in order to prevent spillovers. Even though the shift downwards has not been perfectly parallel we see that it is a pretty good approximation.

An additional observation to make on the supply curve is that the maximum bid volume is placed at approximately 50 000MW in accumulated volume. This falls far short of the previously given maximum capacity of 98 414MW for the Nordic system, something that might seem strange. Nuclear production was close to its maximum capacity in January of 12 000MW, other thermal production only produced at approximately half of reported capacity. Some capacity has to be reserved the balancing market in order to cope with any deviations prom planned production or demand. In any case it seems that reported theoretical capacity greatly exceeds actual peak production capacity for thermal other than nuclear. Looking at the years 2009-2012 weekly production rate was never higher than approximately 50% of maximum reported capacity.

Wind production will never be at full capacity and its capacity factor at any point in time will be random, its effect on the total production will in any case be modest for the entire system at the present.

There is also a large difference in total capacity compared to the amount visible in the spot markets curve when we look at hydropower. Some capacity is reserved for the balancing markets. Additionally, hydro capacity depends on reservoir level since the head is reduced when the reservoir level is low. Lower water speed in the turbines means lower potential for production since production is proportionate to the square of the speed of the water ($E=1/2mv^2 \approx mgh$). This is likely to be what we see when comparing the summer supply curve with the winter supply curve. The visible hydro capacity has increased in summer (the curve covers a larger interval), as would be expected since reservoir levels are higher in the summer. The effect however is small. In addition the fact that not all power is traded at Nord Pool would also reduce the size of the supply curve. In any case it seems evident that the supply curve is not a 100% accurate representation of true Nordic generation capacity.

Adding up the different sources of capacity might help understand the entire picture.

Maximum volume offered in the spot market was 53 000MW, dividing this by the Nord Pool spot market share of 78%[5] we get peak market capacity of 67 948MW. Peak load in the Nordic region occurred in the morning of February the 23th at 08:00 am, with a total load of 67335 MW (Nordic Energy Regulators, Nordic market report 2012).

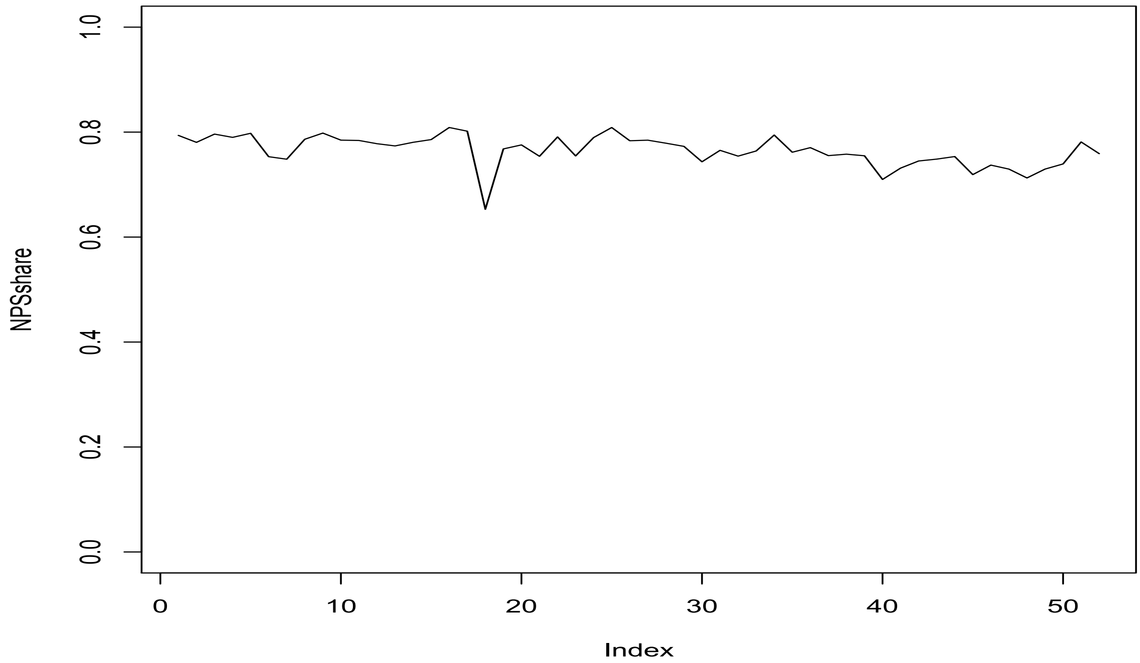
In addition to the spot market a minimum of 600 MW worth of power will be reserved for the regulating market (will not be able to participate in the spot market) in Norway, typically more during winter (see Statnett homepage). The Swedish TSO has a reserve of 1255MW the Finnish approximately 800MW Danish numbers were not as readily available. Assuming approximately 4 000MW of reserve power seems reasonable. In addition some capacity is also reserved for balancing power. These volumes are smaller however. Summing up we have reached a total of 73 000MW, and there is still 98 400 – 73 000 MW = 25 400 MW not accounted for. Wind power accounts for approximately 7 500 MW, although hourly wind production from all relevant areas is not available wind will never produce at maximum capacity since this would mean that wind conditions were optimal at all Nordic locations at the same time. It seems unlikely that this would happen at the hour of greatest load as well. In Denmark maximum wind capacity usage was 70%. In the Nordic as a whole probably much lower since wind conditions become less correlated-

[5] This figure varies over the year and is higher in my estimations than Nord Pools. Nord Pool estimate on share of consumption is 73%

In the years 2009 to October 2012 Nordic thermal other than nuclear production was never significantly above 50% of reported weekly capacity. Realistic capacity is therefore approximately half of the reported and we can take of 14 000MW of the theoretical capacity. This leaves 7 400MW of capacity still unaccounted for. Since total nuclear capacity was almost utilized to the reported maximum capacity, the remaining 7 400MW have to be reduced hydro capacity relative to theoretical. If we divide the remaining missing capacity by reported theoretical hydro capacity, 7 400/48 000 ≈ 15%, we get that it accounts for 15%. A lot of hydropower is unregulated and production depends on inflow, which is typically low during winter. Low reservoir levels for the regulated production facilities also leads to lower capacity since the effects of a turbine depends on the distance between the water level and the turbine which is called the head. The head is reduced when reservoirs are depleted. In the beginning of 2011 reservoirs were significantly lower than normal. In addition some unplanned repairs and maintenance is likely to reduce actual capacity.

Summing up, the reason that we don’t see the entire theoretical Nordic capacity in the spot market is because realistic thermal capacity falls far short of theoretical thermal capacity, the Nord Pool spot market does not account for the entire market, some capacity is reserved for the balancing and reserve market, some is out due to maintenance, some is intermittent such as river and wind energy and additionally low reservoir levels reduce the capacity of the hydro producers during winter time.

These back of the envelope calculations are not meant to give a precise description of the state of the actual Nordic generating capacity. They do however provide a rough estimate and they provide a background upon which it is possible to outline the supply response to increased trade. In any case it seems clear that real generating capacity is significantly lower than the theoretical generating capacity.

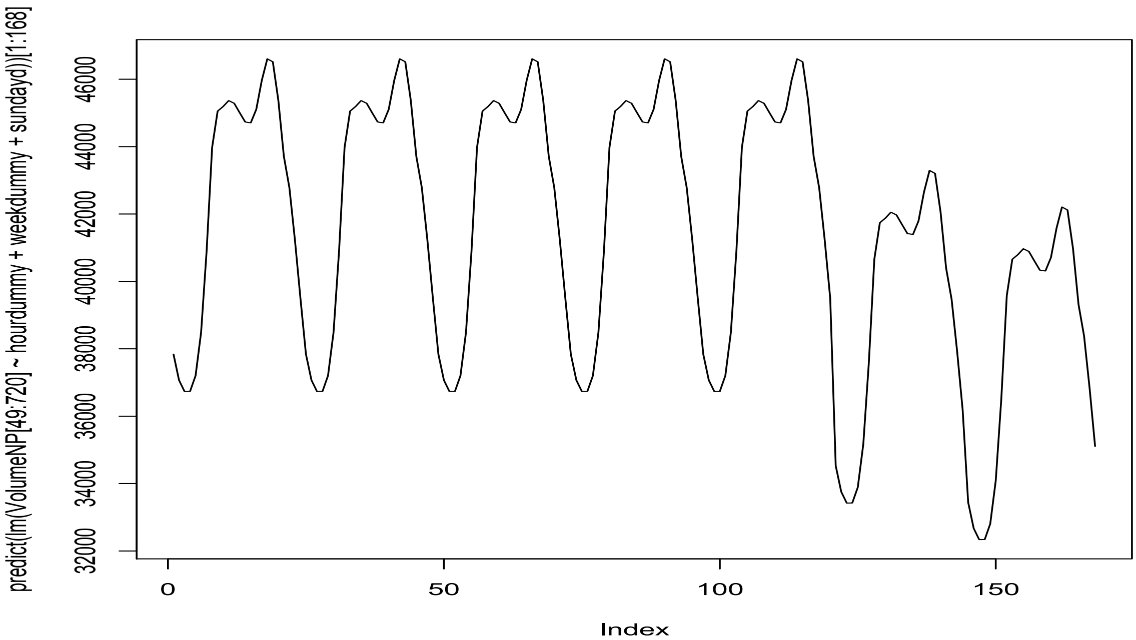


Graph 10: Nord Pool spots share of total production plus imports (weekly). Imports from Russia not included. (Data source Nord Pool)

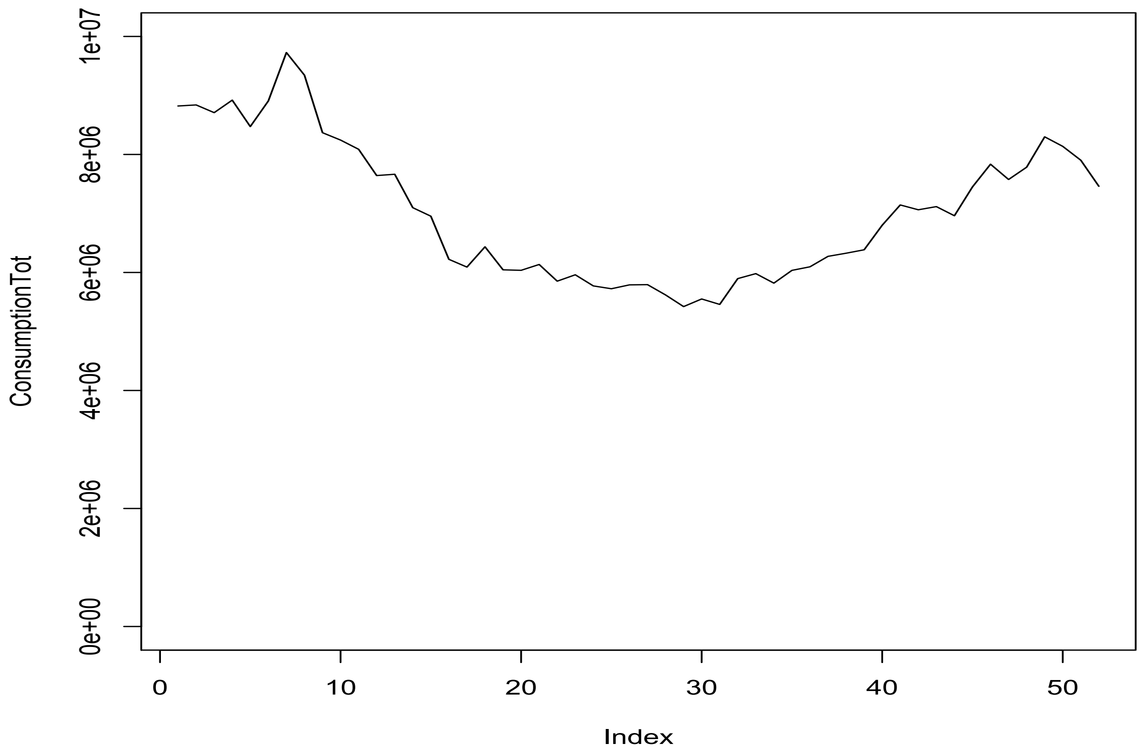
1.2.2 Demand curve

The demand curve does not stay constant as we can see from graph 6-8. The shifts are frequent over the day and we notice that it is much more inelastic than the supply curve, at least in the short run since the curves give limited information on behaviour in the long run.

The shifts are pretty predictable and rely much on whether it is a weekday or a holiday, the temperature and the time of the day. Typically demand is higher on weekdays, it drops during nighttime, and increases with lower temperatures. Patterns are shown below for daily, weekly and seasonal variation.



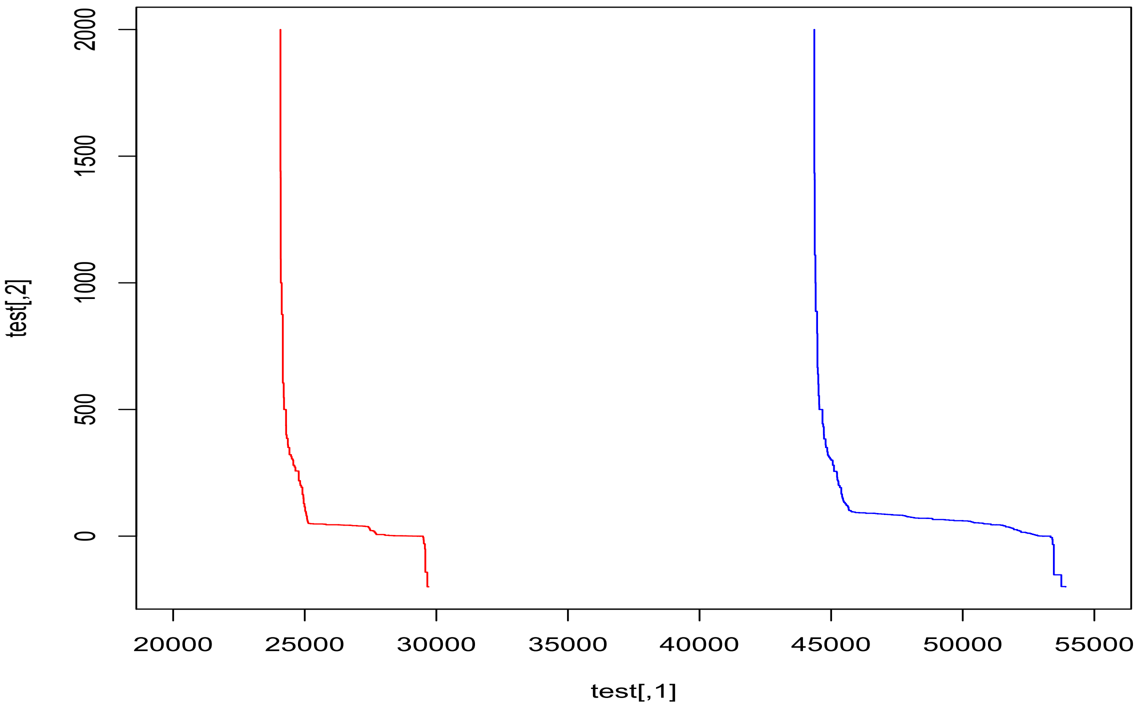
Graph 11: Typical diurnal and weekday variation in load in MW (Nord Pool data). Noise has been removed, based on predicted January values. (NB the pattern is forced by dummy variables for weekday or weekend, hours and Sunday estimated based on January values)



Graph 12: Seasonal variation in demand shown as Nordic production plus net-imports (excluding Russia) in MWh/week 2011

It is useful to divide sources of demand into three groups when describing demand patterns; private demand, industrial demand and demand from businesses and the service sector. The first type of demand consists of households and goes mainly to heating and the use of other electrical appliances at home. Typically the demand is low when people are sleeping, it goes up when people get up in the morning and turn on different sorts of electrical appliances. It falls again during the day when people are at work, and then peaks again when they get home. In addition it is negatively correlated to temperature as much of private consumption of electricity in the Nordic countries goes to heating. The private demand is completely inelastic in the short run because consumers are not exposed to the hourly price signals from Nord Pool. They pay monthly or quarterly electrical bills where there is no differentiation with regards to when the power was consumed. In the long run however, utility companies can adjust their prices so that consumers may be affected by a higher price level, still they will not be affected by hourly price changes, and demand over the day stays completely immune to price signals from the spot market. Utilities have to estimate the demand of their consumers since they will have to pay for costly balancing power in the hours when the amount they have purchased does not equal the amount consumed by their consumers (The Nordic Electricity Exchange and The Nordic Model for a Liberalized Electricity Market, Nord Pool 2004). Utilities are therefore willing to purchase power at a high price at the amount of estimated consumption since they are bound by contract to deliver electricity to consumers. This estimated consumption will vary over the day for reasons already explained. The demand from utilities providing electricity to households is likely to be almost completely inelastic, but to vary a lot over the day.

Industrial demand is mainly inelastic in the short run as well for some of the same reasons as thermal supply. It is costly to stop and start production on an hourly basis. Therefore industry is much more sensitive to the price level than to hourly fluctuations, and in the hourly demand curves they appear more or less inelastic. Some industry however can turn on and off production, and that is likely to be what we can observe in the somewhat elastic part of the demand curve. This is especially true for electrical boilers supplying heat to industry and houses; this is likely to make up most of the elastic part of the demand curve. The graph below confirms the suspicion as we can see that the elastic part of demand is much lower in the summer when the need for heat is lower.



Graph 13: Peak demand Monday 11. July (red), peak demand Monday 3. December (blue)

Demand from businesses and the service sector is highest during the hours when people are at work and electrical office appliances, air conditioning systems and heating systems are used. This is during the daytime and on weekdays. Demand from the business and service sector is therefore highest during these hours, and it is inelastic since most of this sector does not face the hourly price signals since they mostly buy electricity through utility companies and not in the spot marked. In the short to medium run they face the price stipulated in the contract with their utility service provider, which is often constant and not differentiated by the hour. Therefore this part of demand varies inelastically over the day and the week, with highest demand during weekdays and in office hours.

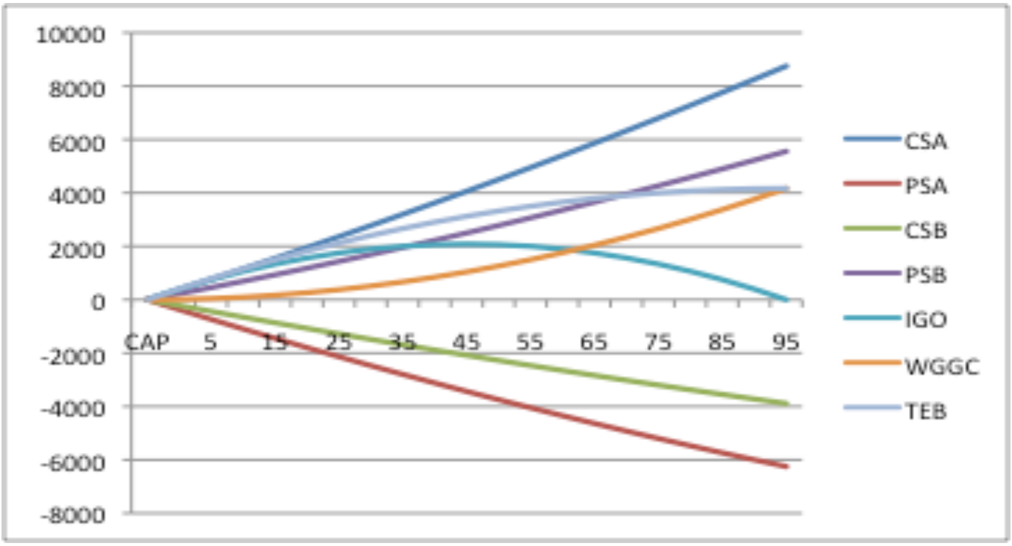
2. PART II

2.1 The benefits of trade

Trade is always beneficial from an aggregated economic perspective and even though free trade might still be controversial to some interest groups due to the effects not necessarily being Pareto efficient. In an academic perspective they have been quite uncontroversial since the works of David Ricardo on international trade and the theory of comparative advantages.

The same goes for trade of electricity and the benefits are larger the greater the differences in comparative advantages. Different production technologies have different strengths and weaknesses, trading reduces these strengths and weaknesses when different technologies are pooled together in the same market. Increasing the size of the market also reduces the opportunity of a single actor to exercise market power. On the demand-side, integrating markets where demand patterns are less than 100% correlated reduces the need for reserve capacity since peak load relative to average load will be reduced. Improved merit order is another source of economic benefit as production will come from the sources that can provide it the cheapest at all times.

A simple model can be used to illustrate that even though overall effects are positive for all markets that are involved in the trade (at least when necessary investment costs are excluded), all agents in each economy might not benefit, in the case of electricity trade, some agents are actually likely to lose. The model is taken from Wangensteen 2012, p 191) numbers are random and will differ from the figure presented by Wangensteen. The interesting part is the shape of the different functions.



Graph 14: Trade model. CSA=Consumer Surplus market A, PSA=Producer Surplus Market A, IGO=Income Grid Owners, WGGC=Wealth Gain Grid Customers, TEB=Total Economic Benefit

These are stylized social economic effects of the integration of two separate markets, market A, with a relatively high price and market B with a relatively low price. The Y axis describes the change in benefit while the X axis is the trade capacity as percentages of capacity needed for full integration. Beyond 100 % nothing changes as capacity is no longer a constraint.

Obviously consumers will gain in the expensive markets as prices get lower with more trade and they consume more at a lower price. Producers in the expensive market will lose because they will produce less at a lower price. The sum will however be strictly positive since consumers will always take over the entire loss of the producers while at the same time gaining some more unless demand is perfectly inelastic.

For the agents in the cheap markets the effects are exactly opposite. Another interesting feature is the income for the grid owners, or more precisely the ones that own the transfer capacity. They make money by buying cheap electricity and selling expensive electricity. As transfer capacity increases they will be able to trade more, but at the same time the price gap between the two markets will become smaller. Their profit function is therefore concave because the effect of smaller price difference will eventually dominate the effect of larger volume. When markets are perfectly integrated, there is no price difference and no bottleneck income.

Total economic benefit is simply the sum of all other benefits. It increases quickly in the beginning and then flattens out until it becomes completely flat at 100% capacity. From a social economic perspective, the optimal investment is not likely to be full integration. The optimal solution is where the marginal cost of installing more capacity equals the marginal social benefit. That is when the derivative of the TEB function equals marginal investment cost. This is not likely to be at the same point as grid owners would want it if they have monopoly on the capacity, they are also likely to want to reduce transfer capacity at some points in time when prices are relatively similar. To see this, imagine a point in time when price differences are small and the installed capacity is sufficient to fully integrate the two markets, something that would be socially optimal. For capacity owners, it will be profitable to reduce transfer capacity such that price differences occur, if not they will receive no income. The problem would be solved however if one agent only owned part of the transfer capacity, then competition would push outcome towards cero price difference and full integration for that hour. (Here I have assumed implicit auctioning of the transfer capacities, as it is done for the capacities handled at Nord Pool. Having an explicit auction would not give very different results however. If grid owners sold the capacity, any price on this capacity would lead to different prices in the two markets. A(n) (unregulated) monopoly would still choose to charge the price or the quantity that would give the highest profit. The price and volume are as always mirror images of one another.)

2.2 More specifically on the integration of the Nordic and the Continental markets

Production is very different in the Nordic market compared to the potential trade partners. Hydropower is the dominant source of production in the Nordics while thermal production from coal or nuclear dominates the other markets. Hydropower is highly flexible with regards to adjusting production to accommodate hourly price fluctuations and is a cheap source of balancing power. Coal and nuclear on the other hand are not. It is costly, and there is only a limited possibility to adjust production on an hourly level and fluctuations in price in thermally dominated markets are therefore large. In the Nordics hydropower also supplies base load power since it is so dominant in total production. Base load power is less valuable than peak load power and in some sense we therefore have a source of undeveloped value in hydropower. Hydropower is also a great source of balancing power, something that will become even more valuable as an increasing amount of intermittent energy sources are phased into the power system.

When there is little rainfall prices soar in the Nordics because of the dependence on the hydro production, especially during the winter. Hydropower provides great short term security of supply, but yearly production potential can vary with as much as +-40 TWh with an average yearly production potential of 200TWh (Nord Pool 2004, The Nordic Power Market - Electricity Power Exchange across National Borders). Coal and nuclear production depend only on access to fuel, which within the foreseeable horizon, there is no shortage of. In a long perspective thermal production is therefore a more stable source of supply.

3. PART III

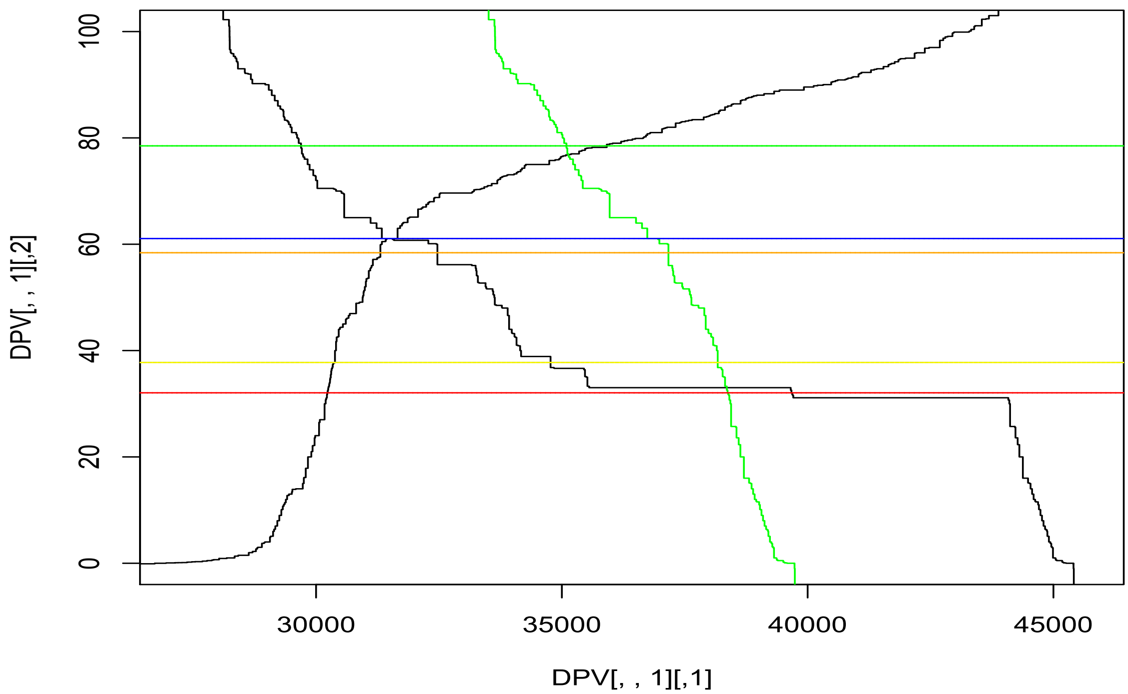
3.1 The main model

The market algorithm that calculates prices in the Nordic market is a company secret of Nord Pool. I have created a code that imitates the Nord Pool algorithm. In one way it is simplified since I do not calculate the amount of block bids endogenously, I simply assume that they will not change relative to the realized amount of block bids. In addition there is no optimal way to calculate prices when you have to take into account block bids, Nord Pool therefore uses a second best approach that becomes quite complicated. The calculations are complicated enough without them and I have chosen to drop this part. Unfortunately they are not available in the form that I would need them in order to include them in the model. Secondly, calculations are already so complicated that running the algorithm on all hours over an entire year demands a handsome amount of calculating time.

In addition I have made trade with adjacent markets endogenous in the model. Different efficiency losses apply with the transfers to different markets. Demand from a coupled market is put equal to trade capacity to that market when the price difference is sufficiently large. This does not mean however that this amount necessarily is traded; this will depend on the supply curve as prices and volumes are calculated at the intersection of the new demand curve and the supply curve.

To Germany additional export capacity of 1 400MW is added such that the different trade capacities become:

Dutch capacity is 700MW, Polish is 600MW, German import capacity is increased from 2700MW to 4100MW, and German export capacity is increased from 2975MW to 4375MW



Graph 15: Model printout first hour of 2011. Blue line modeled system price.

This is a printout of the first hour of 2011 from the model. You can see the supply and demand curves created by the model in black. The supply curve is taken from the supply curve data provided by Nord Pool (including the block bids exogenously), the demand curve takes data for demand bids and adds the block bids, this is the line you see in green. The black demand curve in the graph adds demand from other markets, more specifically from Poland, Germany and the Netherlands. It is easiest to see in the case for Germany since we here have the largest trading capacity. The German price is the red line. Had Germany been the only country that we traded with, the black demand line would intersect the green in this point. At this price however we would export 600MW to Poland and 700MW to the Netherlands since the price is well below the price prevailing in these markets (Dutch in orange, Polish in yellow). Therefore when the price is in between the two German prices we get when we account for transmission loss on export and import, the black demand curve runs perfectly parallel with the green line 1 300 MW to the right of the green line. When we get below the price we would need to be able to export, a demand equal to the export capacity to Germany is added. When the price is higher than the price we would have to import, demand is reduced by the import capacity from Germany since any demand above this price will be partly covered by imports and not by domestic production. This is why we have the horizontal shifts in the demand curve right above and right below the German price. The price we get when exporting will always be lower than the price we get when importing. This is because of transmission losses. On the cable to the Netherlands for instance average losses are approximately 4% (reported at 3,7% at 600MW by ABB, Skog et al, The Norned HVDC cable link – A power transmission highway between Norway and the Netherlands.) This means that the price we get when exporting effectively will become 4% lower than the price paid in the market we export to. The other way around, when we import we have to pay 4% more for the power in the Nordics since 4% of the power bought is lost, mainly to heat provision for the fish living in the North Sea, and they do not pay for this service. For the other lines losses have been set to 3% since these lines are shorter. For the Polish market where prices are in Zloty they have been converted to Euros using daily exchange rates from the European central bank.

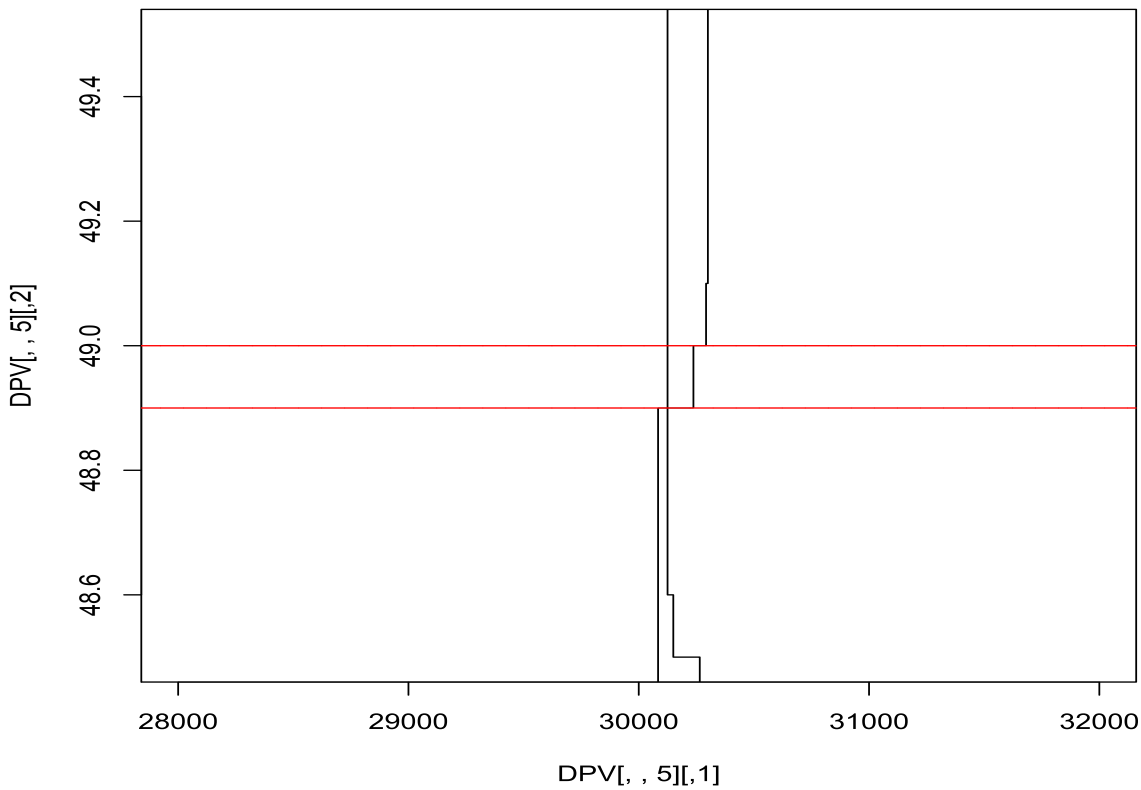
3.1.1 How trade affects prices

Opening for trade with another market is the same as adding demand or supply from this market at the price that lies below export price (demand) or above the import price (supply). The model manipulates only the demand curve by adding or subtracting demand as already explained. Since it is always the marginal bid that sets the price, the price of the import or export volume has no effect on the price in the market directly. It is the size and the sign of the net export that affects the clearing price in the Nordic market. As long as the price in the other market is high or low enough to make the interconnectors be fully utilized the size of the price difference is irrelevant when calculating the Nordic system price. Unless import or export demand is the marginal bid, their price has no effect on the system price.

The import and export prices however are the prices that the grid owners face. The price for consumers will always equal the price that clears the market. Any difference will be income for the grid owners. Indirectly price differences will affect grid customers since grid owners are heavily regulated and the profits they get from price differences between trading markets have to be given back to producers and consumers through lower grid tariffs (Statnett 2011, The main Grid tariff 2011). This is because TSOs only charge customers the operating cost of the grid minus other income.

3.1.2 Finding the optimal market clearing solution

Since demand and supply are not actually functions but rather sets of discrete values there will (at least almost) never be exact matching of supply and demand since bid volumes are not likely to be exactly equal for a given clearing price. The intersection of two discrete curves will give either a socially optimal price or a socially optimal volume. Unless the marginal bids on the supply and the demand side are placed at the exact same price and aggregated volume there is no single correct optimum solution for the problem. My code chooses the solution where the bid that is only partly delivered sets the price while the bid that is accepted in full sets the volume. Whether the supply or the demand bid sets the price or volume depends on the nature of the intersection.



Graph 16: Intersection of supply and demand curve. They are not actually curves but sets of pair values of volume and price. A stepwise portrayal has been chosen for pedagogical reasons

In this case there is one socially optimal volume, but the price can be set anywhere in between the two red lines in order to clear the market at this volume. In this case my algorithm lets the volume be set by the demand curve (the only optimal solution) and the price be set by the marginal supply bid, which is not delivered in full. Things become more complicated when bids are placed at exactly the same volume or price. Then the intersection occurs not a “point” but along a line. The algorithm has to able to take into account a number of different ways in which the lines might intersect and this makes things become quite complicated. I will not discuss every single possible price and volume determination scenario and the interested reader and competent R software user may take a closer look at the code provided in the appendix. The important lesson is that there may exist an infinite number of optimal prices or volumes depending on the way the curves intersect. Normally, as in the case above, the interval in which the optimal price or volume may vary is very small, in some cases however the possible optimal solutions will differ within a much larger interval. In order for the random price setting not to affect trade, four new price points are added to the demand curve for each market that Nord Pool trades with. This allows net exports to set the price if the net export demand or supply becomes the marginal bid (this will happen quite often since these bids are relatively large in volume).

When the market-clearing price and volume have been calculated, the amount of trade with the different trading partners can be calculated as well. Trade becomes equal to the volume supplied (which is the market clearing volume that has been calculated) minus the domestic demand at the calculated price. This means that net export is a positive number and net import a negative number in this thesis. Whenever prices at Nord Pool are above import or below export prices in the markets that Nord Pool trades with (cable losses accounted for) the capacity is maxed out. If the price is equal to either export price to or import price from a given market (that is supply intersects the demand curve at either of these prices), volume is set by domestic supply at this price and the resulting import or export from the relevant market can then be backed out given exports to or imports from the other markets.

Income to capacity owners is simply (market price – import price)*trade when importing and (export price – market price)*trade when exporting. Typically this income is split in two between the relevant Nordic TSO and the TSO in the coupled market since they typically own 50% of transmission capacity each.

3.2 Assumptions and simplifications

Some simplifications are made in the model and some have already been mentioned.

The first simplification is made with regards to the inclusion of block bids. This has already been explained.

Secondly, interconnectors between two markets are typically not operational 100% of the time. In the model they are operational the entire time.

Internal grid congestion within the Nordic market will sometimes lead to changes in trade relative to what the system price would dictate, this is not accounted for in the model since it does not take inner constraints into concern.

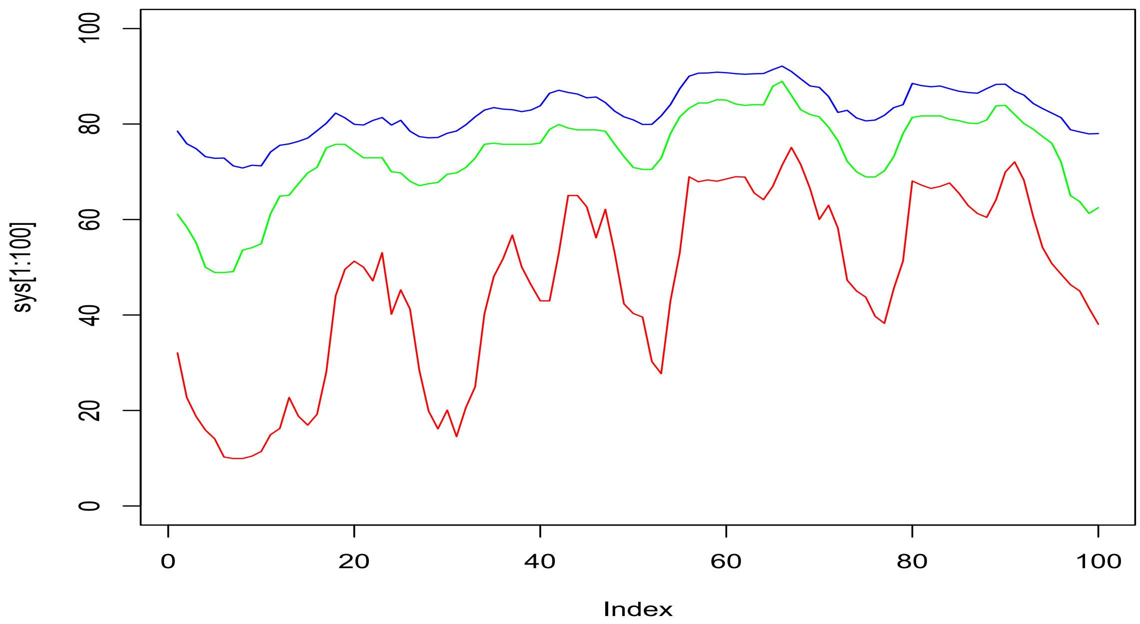
The model also takes foreign prices as exogenous and unaffected by the trade with the Nordic system.

In the model supply and demand curves do not change as a result of the increased trade capacity. The credibility of the model results relies completely on the assumption that the supply and demand curves approximate spot market behaviour also when extra trade capacity is added.

In addition the model relies solely on the data available at Nord Pool. Nord Pool covers approximately 75% of all physical trade in the Nordic countries (excluding Iceland), this means that not all relevant volumes are included in the model. This will again affect the assumption of the fixed demand and supply curves.

The effect that these simplifications are likely to have on the model result will depend on many factors and they are discussed more thoroughly after the results themselves have been presented.

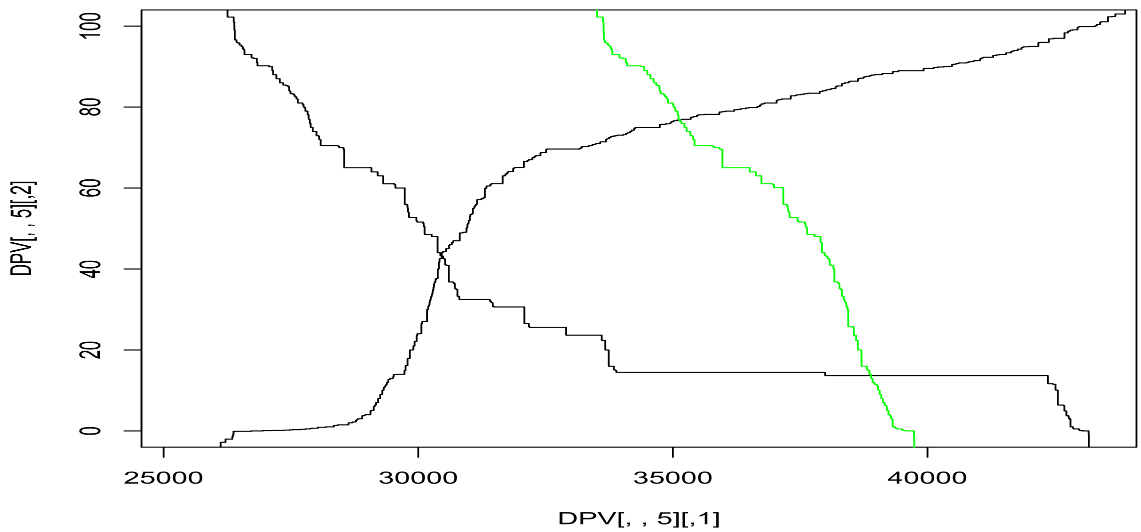
4. PART IV



4.1 Results of model run

Graph 17: Real Nordic system price (blue), modeled Nordic system price (green) and real German price (red) for first 100 hours of 2011

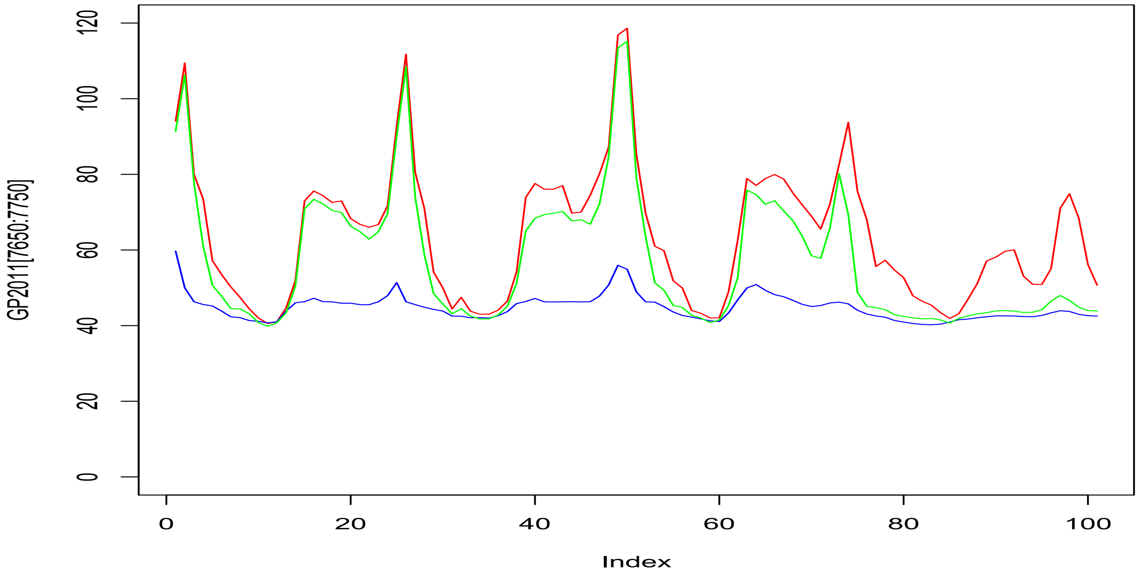
Looking at the start of the year we see that the Nordic price lies constantly above the German (The same is true for the Dutch and the Polish price). This implies that the Nordic countries will be net importers in all hours and that the import capacity has been utilized to its full potential in the model. We also notice that the difference from the original price is largest when the German price is relatively low compared to its average. Price difference should make no difference however as long as it is large enough to make import potential utilized to its full as it is in this period. The fact that the new price follows the German down in the low periods therefore seems to make little sense since we export at full potential the entire time. When the imported volume is the same we would expect that the price effect should be the same. The answer lies in something that is not visible in this graph. Looking closer at a given hour it is easier to see why. The answer lies in the fact that a given volume of imports will affect prices differently for different quantities of domestic demand. Nordic demand is typically lower when German prices are low and this is the explanation for the downward volatility here.



Graph 18: System price calculation 5th hour 2011

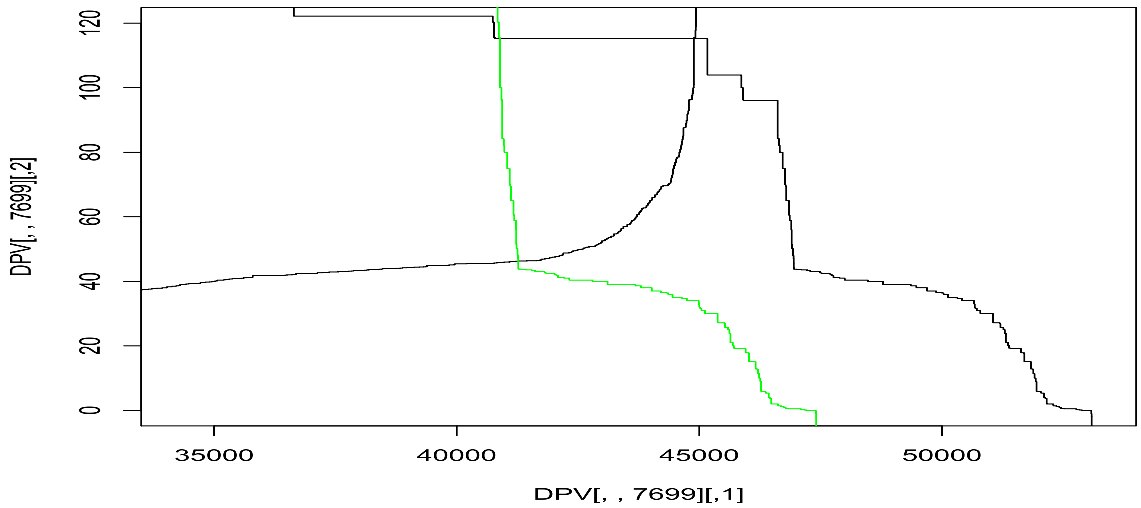
We can see that the increased trade pushes demand over on the inelastic part of the supply curve. When demand is at its lowest, even modest shifts will create large changes in price since we move closer to the inelastic sources of demand, namely wind and thermal. Trade will have a smaller effect on price when demand is higher and further up on the elastic part of the supply curve, since the Nordic market is a net importer at all times the inelastic part of the supply curve will not be reached. This is why prices are more prone to large drops when prices are already low (due to low demand) relative to the average price. My evaluation of this result is that it is pretty robust. Thermal production will lie pretty fixed and hydro producers cannot "move the supply curve" further to the left. This downward volatility can also be seen in the real system price during parts of the season. What might happen is that due to the lowered price level in this part of the season the hydro producers adjust their alternative valuation of water down, thus moving the supply curve downwards. This effect might however be counteracted to some degree by the fact that the increased trade capacity increases alternative value of water further into the future when continental prices are expected to lie above the Nordic. In any case a reduced alternative value of water will reduce the downward volatility somewhat, but not dramatically, since the demand curve in any case will be pushed on to the inelastic part.

This picture can be contrasted to what the model estimates for November.



Graph 19: Price pattern mid November

In November German volatility doubled, reaching peak prices of more than 120€/MWh. The model predicts that the Nordic price follows the German price almost perfectly for some of the days. Again the explanation is not found in the large price difference but rather in the fact that also Nordic demand was generally high and close to peak capacity (as portrayed in the spot marked) for some of the days. Again a close up of the most extreme hour might help to clarify.

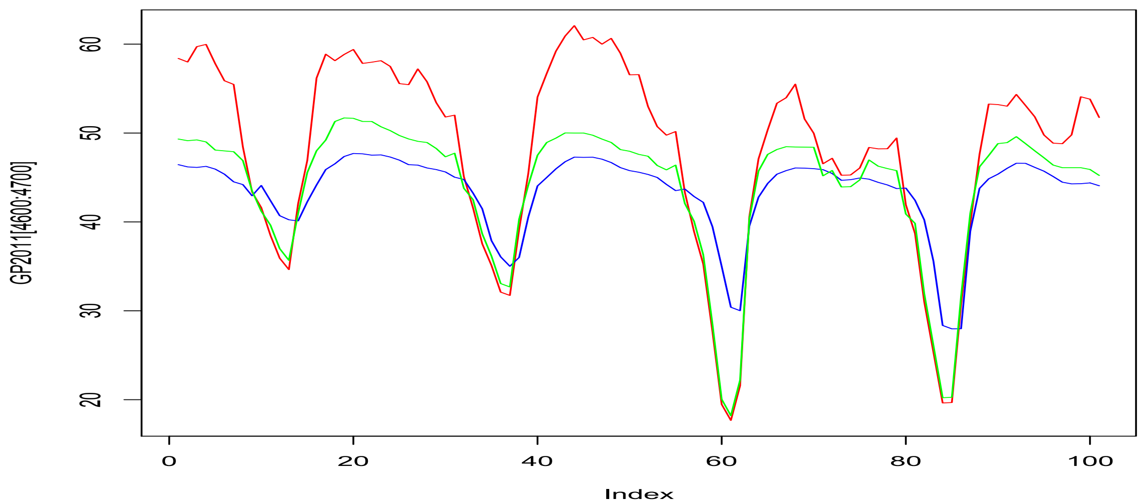


Graph 20: 17. of November, hour 18:00-19:00. Illustration of upward volatility. High Nordic peak demand has already pushed supply close to max capacity (as reflected in the spot marked). The German price (transfer loss accounted for) becomes the price setter since available spot capacity is close to maxed out.

In the model prices are raised well above the highest price during the dry winter due to extremely high peak prices on the continent for these days. The effect is likely to be exaggerated since more capacity is likely to come into the spot market, either through increased investment, by moving from the OTC market or through some inactive sources of thermal power when increase in price level is somewhat permanent. This will even out prices. This latter effect on the other hand is likely to be limited since most of thermal capacity (other than nuclear) in the Nordic is CHP which primary function is to provide heat. The upward volatility seen here is likely to be much higher than what is realistic since we can see that small changes in the supply curve capacity would lead to large price drops.

The degree to which this additional capacity is available depends on the OTC market and thermal production. The availability of thermal power will depend on whether the large average price increase could be expected or not. Since the capacity reflected in the spot market is likely to be underestimated, this extreme peak load effect is probably overestimated. We notice that demand for this hour is approximately 45 000MW, well below the real Nordic generation capacity. For this period it seems likely that more capacity would have been sold in the spot market if the trade capacity were to be increased, this would increase the elasticity of the supply curve. At the same time the curve is likely to move upwards reflecting the increased value of water. In any case for these extreme hours one should be careful in interpreting the results as they are likely to be very sensitive to some of the simplifications made in the model.

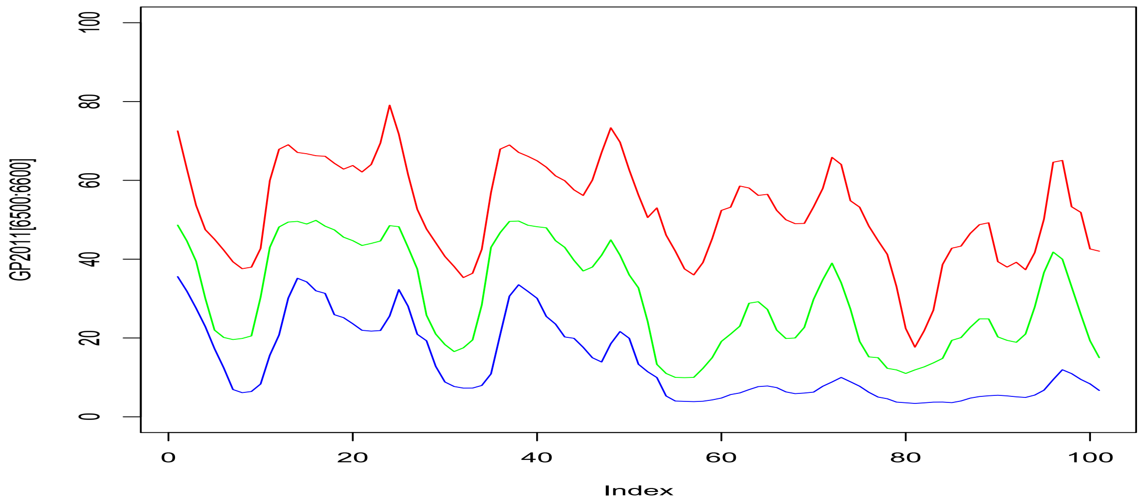
In between the extremes we have the case when price levels are similar on the continent and in the Nordic market.



Graph 21: Price pattern July

In July we recognize some of the same volatility pattern as in the beginning of the year. The Nordic price follows the German price down but is more reluctant to follow the German price up. The situation is the same for the low demand periods since demand is pushed onto the inelastic part of the supply curve. The downward capacity adjustment is difficult however and the downward volatility is therefore likely to not be overestimated. The fact that we already observe this pattern in the realized system price strengthens the theory of robust downward volatility. The model results therefore seem to be quite realistic for this period. Price level is not likely to change much as price levels are approximately equal. It is however interesting to note that it is not the mean but the median price that determines whether we have net-export or import. That means that whether we have net exports or imports does not only depend on price level, but also on structure (See graph 27). It will depend on the number of hours that the German price is higher than the Nordic, not the average prices compared to oneanother.

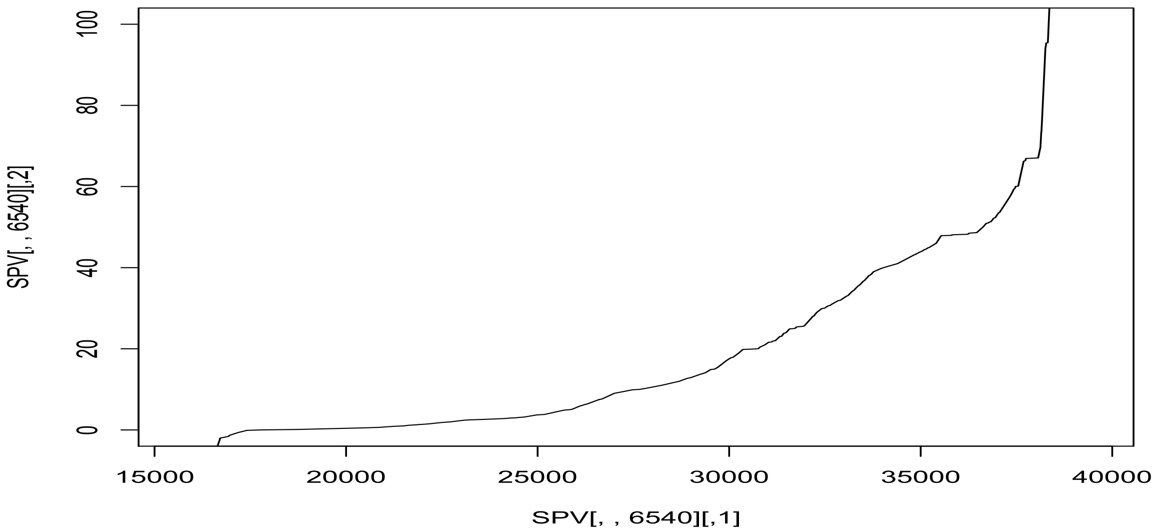
The times when price levels are similar in the Nordic and on the continent are also the times that we are likely to experience the highest hourly volatility since the variance in demand increases. This is because supply is added when there is low demand and demand is added when there is high demand, thus creating pressure on capacity in both ends.



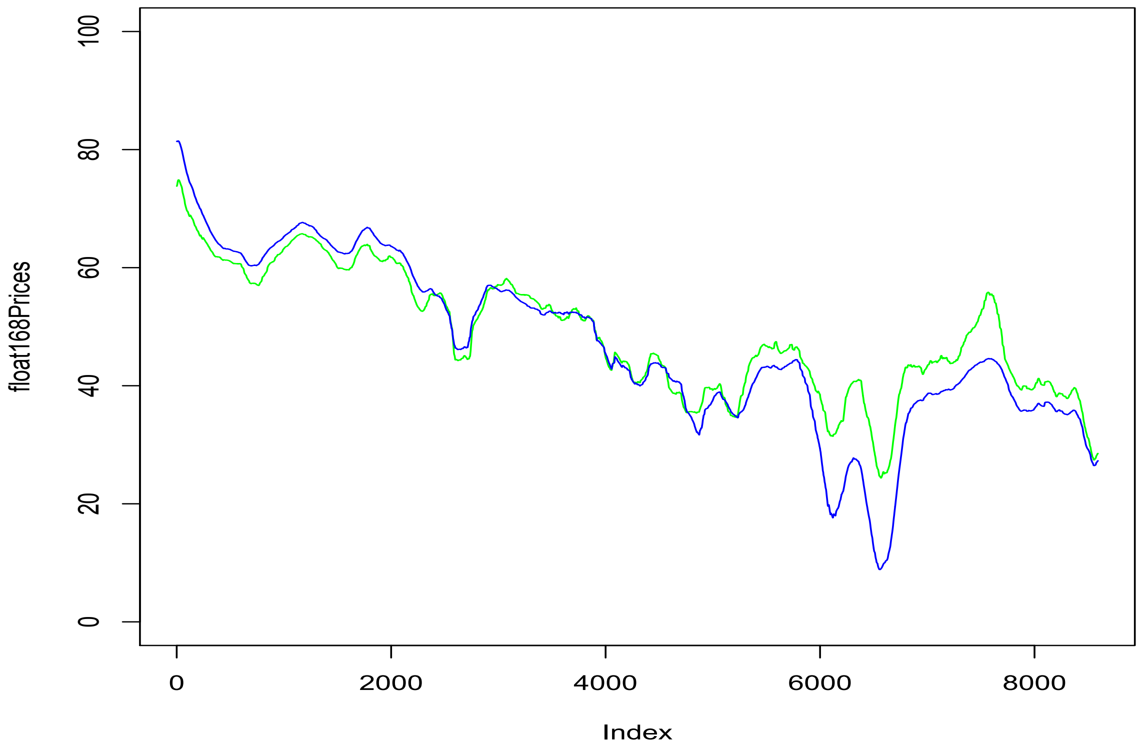
Graph 22: Price pattern September

The September prices show a situation similar to the November case only that German prices are more stable and both prices are lower. Nordic power is very cheap as hydro reservoirs are close to full forcing hydro producers to sell. As the hydro reservoirs are close to full this starts to be an important restriction on some of the hydro producers while others with larger reservoirs are less affected as they can plan at a longer horizon. In September modeled reservoir levels are close to real levels so the effects modeled seem relatively realistic.

In the last part of the graph upwards volatility is significant. This is due to a more than normally inelastic supply curve since full reservoirs create larger differences in water valuation among different reservoir owners as the reservoir becomes a strict restriction on some producers. Increases in demand push production on to reservoirs that have longer planning horizons and thus higher alternative valuations of water. The ability to export more might increase water values for all producers creating a shift upwards in the curve and even higher prices.



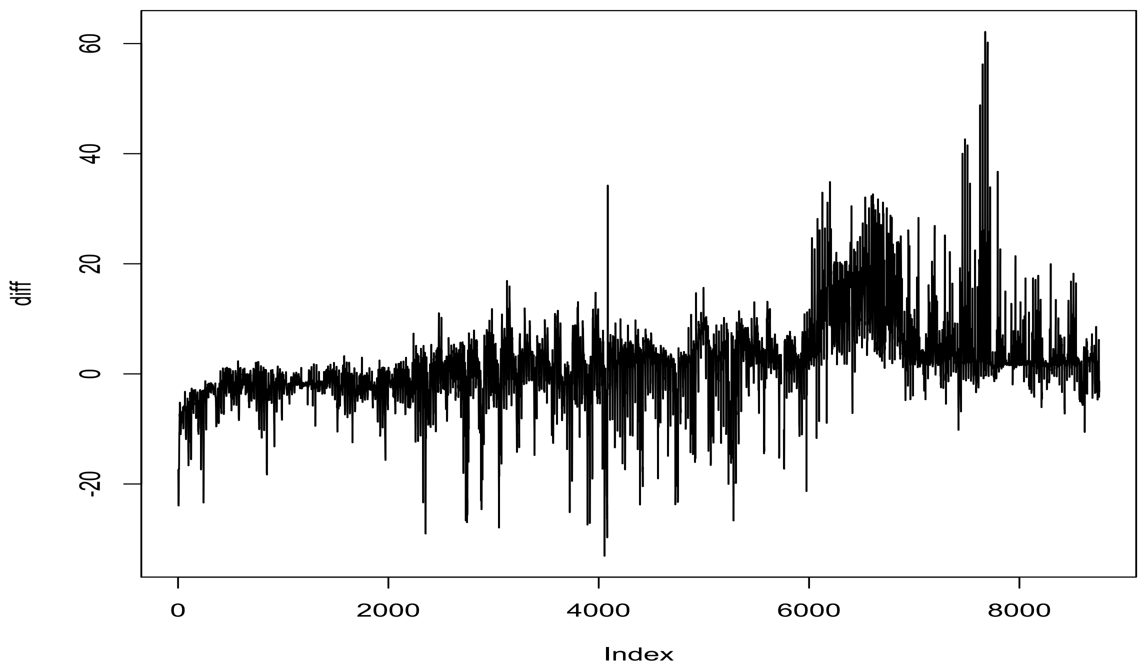
Graph 23: Supply curve September. As some hydro reservoirs are close to full they are forced to sell electricity at any positive price in order to prevent spillovers. The size of the reservoir (and also variations in inflow) becomes an important limiting factor in the valuation of water to some producers and is likely to create a more heterogeneous water valuation amongst them. This is reflected in a different supply curve relative to what we have seen earlier.



Graph 24: Floating average weekly (168 hours) price. Green line model price, blue original system price

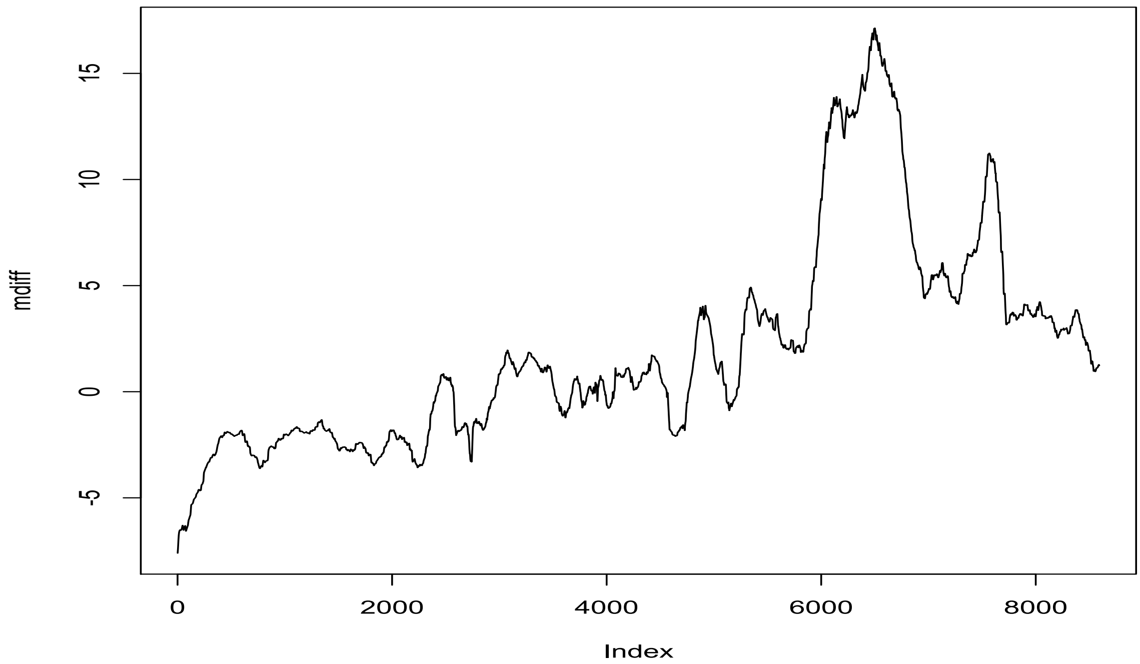
Looking at estimated price level over the entire year we see that prices are lowered during the dry winter season and that they are increased drastically during the very low price period at the end of the year. Looking at supply curve above this might not seem so unrealistic for September/October since the extremely low price is due to some hydro producers having very full reservoir and being forced to sell. When the opportunity to sell more arises this will induce some of the suppliers with a longer time horizon to produce as well and they are not in the same desperate situation thus demanding a higher price. The relatively low elasticity of supply in this situation makes results relatively credible. In addition during this period modeled trade increased with almost 5 000 MW. This is because the Swedish TSO reduced interconnector capacity to Denmark in order to relieve inner congestion in this period, which again led to reduced imports from Germany. It was this situation that led to the complaint filed by Dansk Energi and which led to the division of Sweden into four price areas a couple of months later (Sadowska & Willems 2012). The modeled trade therefore also differs significantly from actual trade something that also explains the large difference in system price. Looking at the November situation however (around hours 7700-7800) we have a peak average at around 60€ per hour MWh. This effect is however likely to be very exaggerated. Going back to the November example from earlier we learned that the high prices were likely to be due to an unrealistically low portrayal of upward capacity in the Nordic market. If this is the case then real supply is not as inelastic as the spot market indicates and prices would not rise close to as much as the model predicts.

Increased volatility will increase the water value in the reservoirs with the highest capacity relative to average production. This is because they will be able to sell more during the high price and less during the low price. This will create more heterogeneous valuation of water among different reservoirs and a more inelastic hydro supply curve.



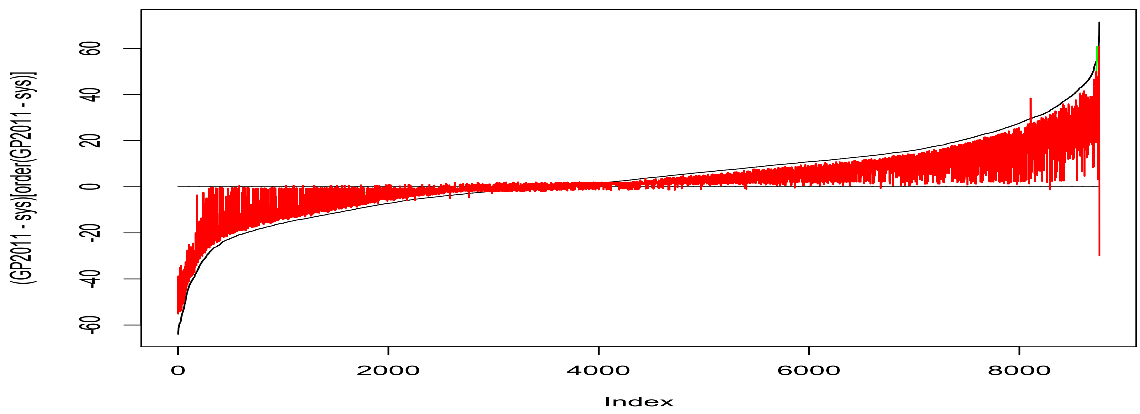
Graph 25: Hourly difference between original system price and new price

On an hourly basis the difference in original system price and model price can be quite substantial with a difference of more than 60€ /MWh on the upside and a negative maximum deviance of approximately 30€/Mwh. Especially the upward volatility of 60€ seems wildly unrealistic, it depends crucially on no extra capacity, thermal or hydro entering the spot market. Thermal capacity is unlikely to contribute with large volumes since so much of it is tied to heating. Results will also depend crucially on whether the high Nordic demand combined with the extreme continental prices were expected. If they came completely as a surprise is seems less likely that extra capacity would have been able to move into the spot market to even out prices, this because start up decisions for thermal producers are long term decision. The contract structure and elasticity of demand in the OTC market will also decide to which degree capacity outside the spot market is able to accommodate demand shocks in the spot market. Sustained higher price levels might also affect demand as some industrial production is shut down; this would also counteract the very strong price effect during the modeled November peak.



Graph 26: Floating weekly price difference in price level from original

The difference in price level looks much more balanced than the hourly variation. Most of the time the difference lies in between +5 and -5. The exceptions are during the very low price period in the Nordic and when German prices are really volatile and high combined with relatively high Nordic demand. The raised price level effect during very low Nordic water values is likely to be more robust that the effect of the very volatile and high continental prices.



Graph 27: Price difference between German price and original Nordic system price ordered from minimum to maximum(black curve). Red line German price - modeled Nordic system price ordered by min to max of German price - original Nordic System price. (Some errors due to 25 missing data points)

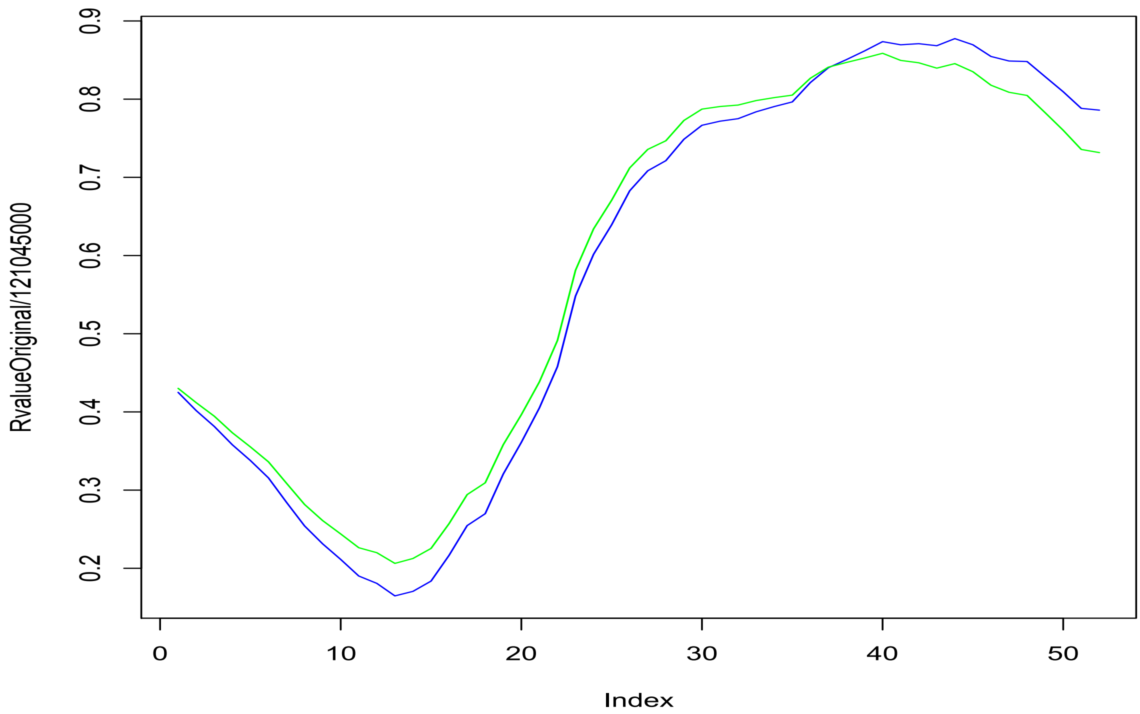
Looking at the graph above we see that the effect on prices has not been homogeneous. Had we had a similar price effects of trade relative to price difference on all hours the red line would be smooth and converge towards the black cero line relative to the black curve. We see that the modelled effect varies by as much as 20€ for the same price difference. (This is also due to the fact that the German market is not the only market that is connected to the Nordic; volumes do however dominate volumes from the other markets)

Summarizing, the effect of the increased trade can be separated in two. First we have an affect on the average price, secondly we have an impact on the short-term, or hourly, volatility of the Nordic system price. All effects are in the expected direction. Price level is evened out over the year with lower prices in the dry winter season and higher prices in the wet summer and fall, and also the wet and mild winter season on the end of the year. For most of the year the price level effect is moderate and in line with other estimates to the degree that they are comparable. (see Thema Consulting 2012, Fornybarutbygging og mellomlandsforbindelser mot 2020). THEMA Consulting estimate that the price effect of 2400MW of new cables will increase the Norwegian price level with 0.8-6.4øre/KWh (depending on four different scenarios). (6.4 øre/Kwh ≈ 6,5€/MWh). Wahl, (Wahl 2012) estimates with another fundamental model that price effect of 3 800 additional MWs of interconnector capacity will increase Nordic prices with 4.5€/MWh over the period modelled, this is based on scenario analysis. The results are as with most other reports and research not directly comparable to mine. Firstly effects will vary over the year and I have used a year where the Nordic price level varied a lot. Most other reports estimate change in annual average. Nordic prices do however vary quite substantially over the year and it is of interest how prices are likely to react at different points in time over the year. Average price was quite high during 2011 at 47€/Mwh, modelled price increase was approximately 1.8€ in my model. The effect varied however a lot over the entire year from a negative effect of 5€ to a positive effect of 15€. Price structure is not modelled specifically over a year in the other reports as it is in my report, and the other reports are based on long-term scenario based development of the price which also complicates any direct comparison since it can be difficult to separate direct trade effects and other effects in these models. In addition they are based on effects during "a normal year". The "normal" effect estimated in my model is roughly of the same size as the estimates by Wahl and Thema.

Short-term volatility increases quite substantially and significantly more than other reports have estimated even though they are not directly comparable. Thema predicts a relatively flat Norwegian price structure. My model predicts considerably higher volatility, but in the Nordic system price rather than the Norwegian. Wahl makes no estimations on the price structure. Even though they are not quantified and they are based on an analysis of the Norwegian power market, model results are very much in line with what is predicted in the research paper published by the Norwegian oil and energy department (Olje og Energidepartementet, NOU 2012: 9,Energiutredningen – verdiskaping, forsyningssikkerhet og miljø).

So far price level effects are likely to be underestimated by the model on the downside. Hourly volatility is likely to be exaggerated in both cases but more so in the upward volatility case as this volatility is likely to induce more investment in hydro capacity and movement of capacity into the spot market, which again will reduce volatility.

The fact that we have net exports in hydro surplus situations and net imports in deficit situations will lead to a more stable hydro reservoir level which is good for security of supply and a more even price level over the seasons and between years.



Graph 28: Aggregate reservoir level. Blue real, green modeled. Assumes that reduction in production in the start of the model comes from reduced hydro production when imports increase and that the opposite is true when exports increase relative to realized net exports.

4.1.1 Effect on consumers

Risk neutral consumers are likely to loose in the long run since the continental prices on average have been higher than the Nordic prices. Consumers are typically not risk averse however and prices are likely to be more stable with increased trade (measured in seasonal and yearly variation. Consumers typically are not exposed to hourly, daily or weekly fluctuations in price). The Nordic winter spikes in prices are unpredictable and high and these are likely to be reduced notably even with moderate increases in trade. For a consumer that appreciates price stability and is risk averse the overall effect is not given.

The modelled and the real consumption at Nord Pool stayed close to exactly identical. At the same time average price increased with approximately 1.8€.

4.1.2 Production[6]

In the model Nordic production is estimated to increase from 282 773 185 MWh to 289 236 147MWh, an increase of 6.5 TWh or 2.3% of original production.

Hydro producers win because of the increased value of flexibility. In the strained winter situation they will loose since prices and production will go down, but they will gain from increased volatility even if the price level is unchanged. When reservoirs became full during summer and fall the price collapse was avoided and hydro producers were able to sell more at a higher price. Modelled hydro income was

7 908 948 867€ which means each MWh was worth 49.1309 on average since modelled (Nord Pool) production was 160 977 075MWh. This can be contrasted to (estimated) real (Nord Pool) hydro production value of 7 222 803 673€ resulting in average price per MWh of 46.9171 since estimated real (Nord Pool) hydro production was 153 948 083MWh. Hydro producers gained through higher prices and an increase in production of 4.6%.

Thermal producers sell more during winter when prices are typically higher. This is not only because they adjust production to prices but also because so much of the production is based on CHP facilities that also produce heat. They will loose during winter but also gain some during summer. The substitution effect is negative since production is higher during the negative shift in prices than during the positive. On average however the model price went up so the total effect on thermal producers is not obvious.

[6] The numbers presented here should not be interpreted as exact estimations. Several simplifications have been made and the focus should be on the changes rather than the size of the numbers. See appendix for full explanation on the calculus used to come up with the figures presented.

Income for thermal producers is estimated to be 8 810 764 921 in the modelled case equalling 50.7889€/MWh on average since production was 173 478 317MWh.

Original thermal income is estimated to 8 633 045 889€ giving an average price per MWh of 49.7644. Therefore thermal producers also gained during this year because the effect of increased prices over the entire year dominated the negative substitution effect of changing prices over the year.

Wind production is of a modest size and hourly wind production is only available for Denmark. It might however be of interest to see how the value of wind production changed. By applying the same calculus to the Danish wind production the value increases from 46.4236€/MWh to 48.1437/MWh. The increase is slightly lower than the average increase over the year. This has probably to do with the fact that wind production is highest during the winter. In the long term when wind production starts to play an important role to the system price, trade is likely to greatly increase the value of wind power since high production will affect prices less with trade.

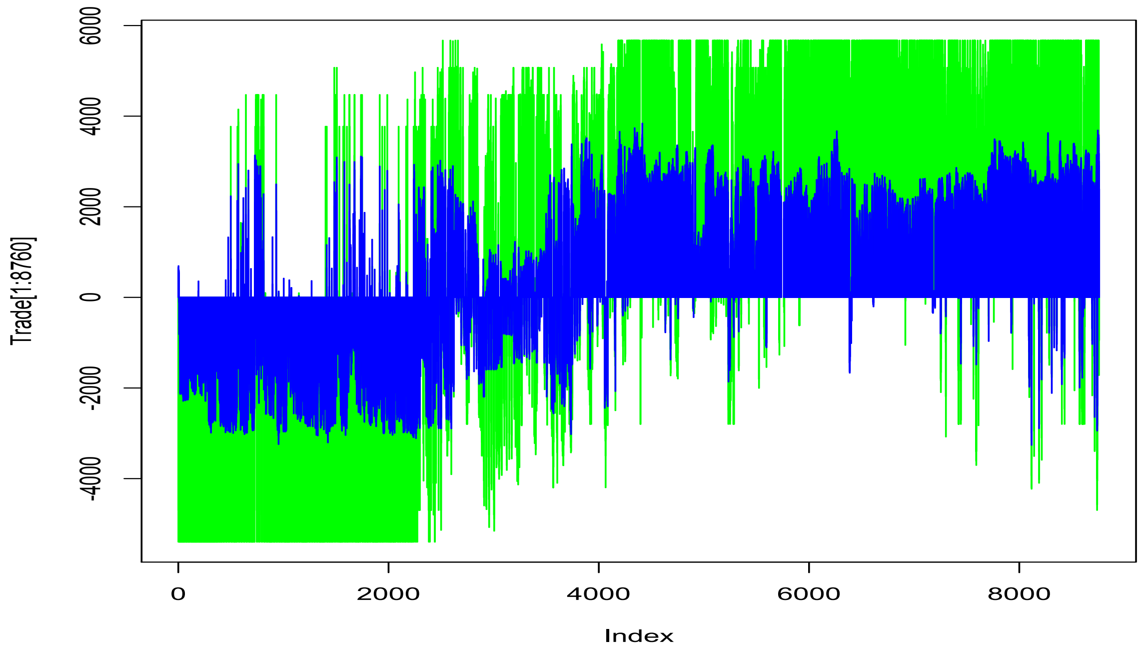
The average price for hydro producers increased with 2.2138€/MWh while it increased with only 1.0245€/MWh for the thermal producers and 1.7201 for wind producers. Average price increase over the year was 1.8404€/MWh.

The prices calculated so far might seem strange as thermal producers on average receive higher prices than hydro producers. In 2011 seasonal variation was much larger than the short-term variation in prices, something that thermal producers can benefit from to a larger degree than hydro producers. As more interconnectors are built however there will be less seasonal and more short term volatility in prices, something that will benefit hydro producers and not thermal producers. This is reflected in the fact that hydro value increased more than proportionately to the average price increase while thermal production value increased less than proportionately to this increase.

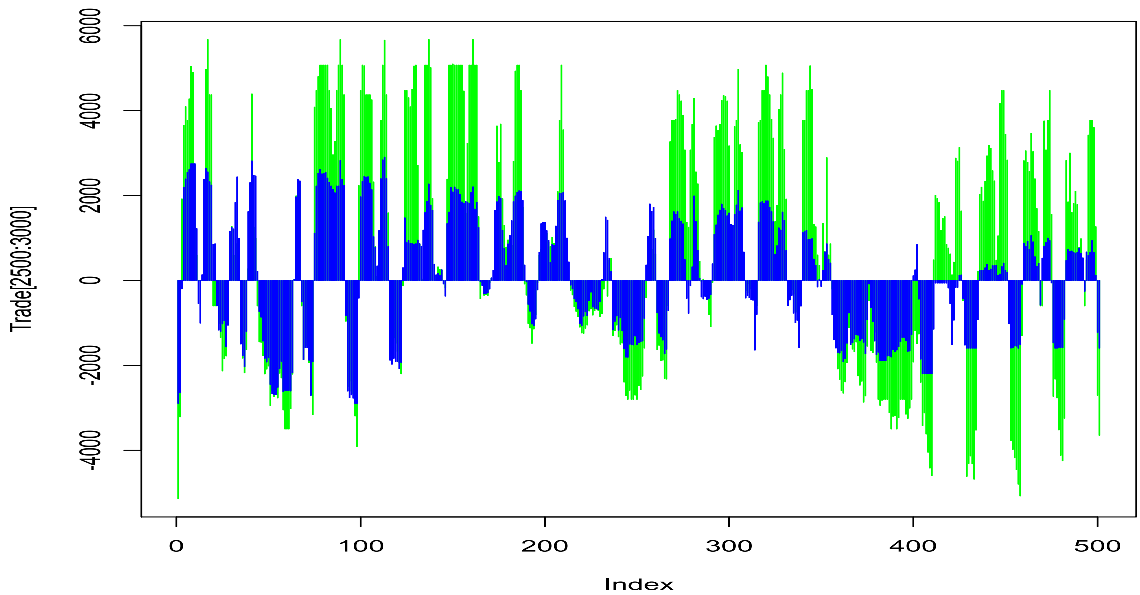
4.1.3 Trade

Net export is more than doubled from 5 563 711MWh to 12 114 782MWh. If we look at total traded volume (for the entire system) the effect is similar. Traded volume[7] has increased from 16 119 785 MWh to 34 653 235 MWh. This might seem like a large increase when we have just added one cable of 1 400MW and original capacity was 3 985MW. The reason for the large increase is the fact that western Denmark, where the largest connection to Germany is, has been more connected with Germany than with the Nordic market. Increased connection to Norway and improvement of inner Swedish capacity and the creation of four Swedish price areas is likely to increase trade with Germany on already existing lines quite substantially. In the model they are utilized to their maximum in a Nordic perspective. Looking at the figure below, the real trade capacity seems to have doubled. The removal of inner constraints therefore has a similar sized effect on traded volumes as the actual added capacity since the actually traded volumes have increased by approximately 3 000MW. This means that the removal of inner bottlenecks also have similar effect on the system price as the actual added capacity.

[7] Traded volume is here net trade for the system in a given hour and not sum of trades to different markets. These numbers are not available historically and therefore not comparable to the modeled results. That means that exporting 600 to Poland and importing 700 from the Netherlands is counted as 100. Since the historical trade with Germany especially has been different from the trade that would be optimal for an integrated Nordic system, hourly net trades might differ substantially between the modeled and the historical results for some hours.



Graph 29: Original real trade (blue) by the hour vs. modeled hourly trade (green) (positive exports, negative imports)



Graph 30: Trade mid April to start May

The different interconnectors were congested different amounts of time. The German interconnector capacity was the least congested and it was congested 66% of the time. The

Dutch connector was congested 75% of the time. The Polish capacity was the cable that was constrained the most and it was operating at max capacity 78% of the time.

The average price differences between the original system price and the German, Dutch and Polish prices were 13.5€, 12.63€ and 10.96€ respectively.

Modelled income on interconnectors were 36 374 083€ on the Polish line, 258 896 802€ on the German lines and 42 140 802€ on the Dutch line, this is total income which would have to be split between the relevant Nordic TSO and the relevant continental TSO. These incomes are likely to be quite exaggerated since inelastic foreign prices are assumed. In addition the model assumes a perfectly integrated Nordic market and no downtime on interconnectors. There is however some downtime in the model due to missing observations, there is however only missing information for 24 hours.

The Nordic system was a net exporter to both Germany and the Netherlands in the model, while it was a net importer of Polish power. Volumes (net) in MWh were:

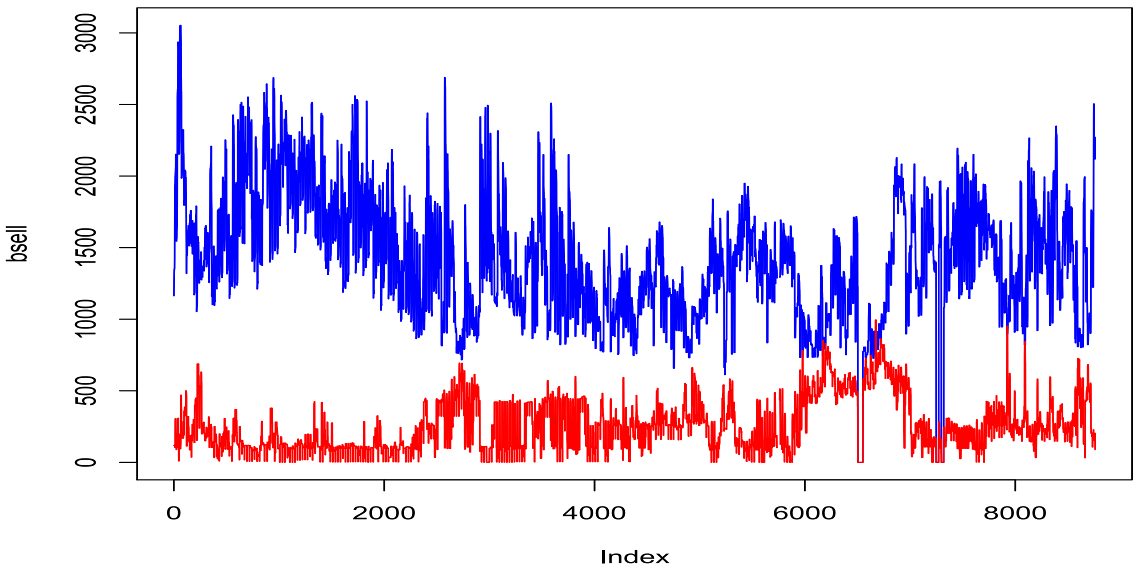
9 991 378 to Germany, 2 148 932 to the Netherlands and 25 527 of imports from Poland.

4.2 The simplification biases

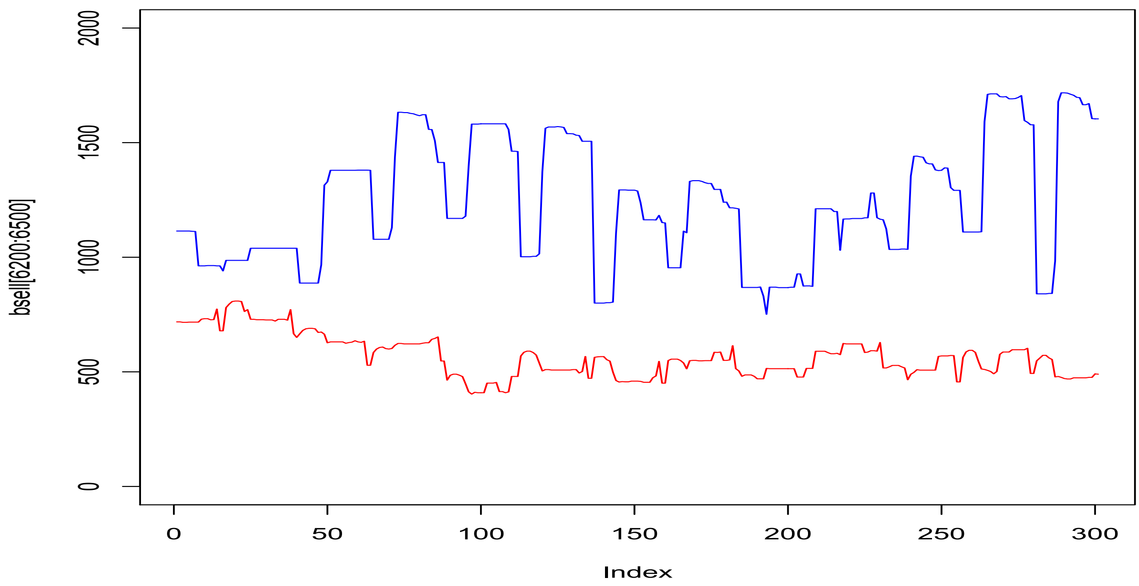
4.2.1 Simplifications with block bids

Block bids are tied to average prices. Increasing the average price will lead to more block bids on the supply side being accepted and a shift in supply to the right. For the demand bids the amount accepted is negatively dependent on the average price, this will lead to less bids being accepted and a shift in the demand curve to the left. Both these factors dampen the effects estimated by the model. In the opposite case where prices go down the bias on the effects of the model will be the same since the elasticity of both supply and demand is underestimated when block bids are taken exogenously. From the graphs below we see that block bid volume varies considerably over the year, the week and the day. This is especially true for the block sell volumes; the buy volumes are very small over the entire year.

The maximum variation in buy volume seems to be 2 000MW, peak occurred at a price level of approximately 80€ at 3 000MW and the lowest value seems to be approximately 1 000MW during the lowest prices. We also notice that there is some significant intraday volatility in volumes. The seasonal variation is not very big, which indicates that changes in moderate changes in price level will not affect the volumes dramatically. As such block bids are likely to be affected by the trade, but for most hours only moderately.



Graph 31: Hourly block sell bids (blue) and block buy bids (red) (the two extreme low points in the curves are due to errors in data material)



Graph 32: Hourly variation in block bids

Regressing the amount of block bids on different price elements has several potential pitfalls. Firstly block bids will depend not on hourly price but the price over different intervals of time. Secondly prices themselves will also depend somewhat on the amount of block bids, something that creates endogeneity through simultaneity. There is also a large possibility of omitted variable bias as many factors tied to seasonal changes might affect both prices and the availability and need for block bids. The effect of prices will likely not be constant either as there are likely to be some thresholds for the volumes of bids. With the data available it seems that it is safest to assume that the block bid simplification has the potential to bias results somewhat but not dramatically.

4.2.2 Inelastic prices in trading markets

It might seem counterintuitive to estimate the effect on Nordic prices and at the same time assume that prices in the coupled markets stay constant. Especially when the Nordic market is a large market by most comparisons. Trade relative to the original case is not changed much however for the Dutch and Polish case where no extra capacity has been added. The trade with Poland has increased somewhat however due to the splitting of Sweden into four price areas and the increased internal transmission capacity that we have assumed in

Sweden. This may affect Polish prices somewhat; the effect is very likely to be small since the change in volume is also small. The Dutch trade has not changed much relative to the original case; therefore the assumption on price here seems unproblematic. The case with Germany is different. Here we have added 1400 MW worth of trade capacity in addition the new cable to the DK2 area and the strengthening of the internal grid in the Swedish south east corridor has increased the realistic trade potential with Germany quite substantially. The German market is however the largest market (approximately 50% larger[8] than the Nordic in volume) of the ones included in the analysis something that makes it likely that any changes in prices in this market due to trade will be smaller than in the other markets.

The fact that the foreign prices probably are not irresponsive to trade obviously affects the results for the Nordic market. The effect however is likely to be much stronger in the calculation of the changes in bottleneck income for the transmission capacity owners than the effect on Nordic prices. Going back to the discussion earlier on the effect that foreign prices had on the price level in the Nordic we concluded that it had no direct effect. The important thing was how much was traded and not the price actually paid or received on the amount in the foreign market. As long as the price difference continues to be large enough for the capacity to be utilized to the maximum, the actual price difference is irrelevant when calculating the price effect on the Nordic market. When price differences are large it makes no difference if the price response in the foreign market is perfectly inelastic or whether it is likely to change somewhat. We also saw earlier that the average price difference was largest towards the German market.

Therefore with respect to this weakness the bias resulting from it is likely to dampen some of the calculated effects when price levels are very similar. When prices are sufficiently different on the continental markets contrasted to the Nordic however, the calculated effects are likely to be very robust. (The exception being the case of extremely high prices. Here the German price sets the Nordic price over a long time interval since it is the marginal bid.

[8] German power consumption was 535TWh (BDWE 2012, Netto-Stromverbrauch nach Verbrauchergruppen Vergleich 2001 und 2011) and Nordic production was 371 TWh (Nord Pool data).

Since German power prices are so inelastic for some of these hours, the elasticity simplification is likely to affect results significantly.) This is good news since the effects we are most interested in are the effects when Nordic hydropower is very cheap or very expensive. In these cases the bias is likely to be small or non-existing on the price effect in the Nordic since traded volumes are capacity constrained rather than price difference constrained.

4.2.3 Data material only covers 70-80% of actual trade

Even though a large share of Nordic physical trade in electricity is handled through the Nord Pool platform, there is still some 20-30% that is handled through bilateral deals. This means that the actual Nordic market is larger than what the data material from Nord Pool would indicate and the effect that a given change in trade would have on the *entire* market is likely to be slightly exaggerated.

The degree to which power supply and demand will enter the spot market when changes occur here or whether the price level in Nord Pool is simply a reference price for the OTC contracts will determine the effect that not all trades are made at the Nord Pool platform. Some thermal production capacity might also be outside both markets and enter the spot market if there were to be major changes in the price level. This would lead us to overestimate both price volatility and price level effects.

4.2.4 Not taking into account different area prices

When Nord Pool calculate the system price they do not take into account internal bottlenecks so this is not a direct simplification relative to what is done in reality. The goal of this thesis was not to describe inner market effects, rather to describe effects on the entire market and the system price.

Even though the system price does not take into account inner constraints the amount traded will be affected. Going back to the case of the first week of January already discussed, the

Nordic system was a net exporter to Germany even though the system price in the Nordic was more than twice as high as the German. This was because wind production was very high in Denmark while thermal production at the same time was at high. The capacity from Denmark to Norway was maxed out and capacity to Sweden was reduced due to large power surpluses in the south of Sweden relative to the north. Denmark was not able to send a sufficient amount of surplus power to its Nordic neighbors and it was forced to sell power to Germany. In my model this would not be accounted for and the Nordic system would be net importers instead of net exporters. Danish-German flow is not available for these hours but net flow in the first hour of 2011 was an export of 600MW. The flow from Norway to the Netherlands was -600 and fro Poland to Sweden -200MW. This would mean that net exports to Germany would have to be approximately 1400MW. The new SK4 cable would take away 700 of these while the division of Sweden into four price zones and the improvement of the north-south grid would lead to Norway and Sweden being able to import 700+600+1300 = 2600 additional MWs from Denmark. This would likely lead to Denmark being a net importer instead of net exporter to Germany for these hours. In addition the Swedish-Polish line would likely be utilized to its maximum as well as the Swedish-German line.

In any case, when internal bottlenecks lead to changes in the Trade with other markets, this will result in changes in the model result relative to reality. Parallel to the simplification of inelastic foreign prices, inner bottlenecks will only affect the result when they are large enough to affect the calculated trade in the model. If the price divergence between the area connected to the trading market is not large enough to cause reduced trade, this will not affect the system price. It will affect the grid owners' income on the interconnection however, which might lead to an incentive for the grid owners to reduce interconnector capacity relative to the socially optimal solution.

The model assumes some major inner grid improvements. Some major improvements are already planned and these improvements are likely to make the model much more realistic. The simplified handling of foreign trade does however make it difficult to attribute the effects on Nordic price level solely to one source. The results of this model should be interpreted as price effects contingent on both the added transfer capacity to Germany and the necessary intra market improvements on the grid necessary to take advantage of the capacity that is already installed as well as the new capacity addition. As we saw earlier the increase that happened in trade was equally attributable to the inner grid improvements as the actual new interconnector.

4.2.5 Fixed curves

The assumption of fixed curves is obviously a simplification as supply and demand is likely to change behaviour somewhat as a result of increased trade capacity. It is probably a good approximation to assume that the thermal production is pretty much given. Gas fired production is likely to either be visible in the marginal curve, as such we will not make any simplifications with regards to them, they will be accounted for in block bids, or they are simply used as reserve capacity. The only problem her is the block bid part and that has already been discussed. The condensing coal plants will probably adjust their production to the forward price level. Maximum theoretical possibility for adjustment for this group is approximately 5 000MW, which is the total installed capacity. Practical ability to adjust production is probably considerably smaller. In any case assuming complete inflexibility of thermal power on an hourly basis seems unproblematic. Looking at the modeled price level it seems reasonable to assume no reduction in thermal production for any price period since the price level is only reduced in the high price part of the year and the reduction is moderate. The lowest summer prices are avoided however something that might increase thermal production in this period. The increase could only be moderate however since the price is quite inelastic in this part of the season and any increase in supply would likely lead to prices dropping quickly. In any case, since it seems unlikely that thermal production would decrease at any time due to the increased interconnector capacity the downward price volatility prediction stays pretty robust.

Hydro producer are likely however to adjust their valuation of water and move the curve up or down. This means that we are underestimating the price level effects since curves will shift in the same direction as the movements in price level (roughly).

4.2.6 Biases summarized

The model suffers from a handsome amount of biases that are likely to affect results differently. Even though the conclusion on many of the volume effects of the biases likely are small, even small changes in volume can affects pries dramatically when we reach the inelastic part of the system price curves. In the table below a qualitative evaluation of strength and direction of biases are summarized. + means slight upward bias (the simplification leads to overestimated results from model), - - - - - - means that this simplification bias leads to a large underestimation of this modeled effect.

Bias	Effect on Price level up	Effect on Price level down	Effect on upward volatility	Effect on downward volatility
Block bids	+	+	+	+
Inelastic prices	+	+	+	+
Incomplete data	+	+	+ + + +	0
No area prices	+	+	+	+
Fixed curves	- - -	- - -	+	0
Total	+	+	++++++++	+++

Table summary should be interpreted with caution. From the previous discussion we learned that biases would have stronger effects in some periods than in others. In addition volatility and price level are not independent sizes. A period with high upward volatility will affect the price level as it did significantly in November, which resulted in what is probably a significant overestimation of both volatility and price level. If we conclude in general terms however it is likely that price level effects for most of the year is only slightly overestimated, the same conclusion can be drawn with regards to downward volatility. Upward volatility is likely to be overestimated. No difference in area prices can also be interpreted in two ways. First it does have great effect on system price when it affects imports. But as discussed this effect is likely to be greatly reduced, in any way if we interpret results as based on a perfectly integrated market, it is no simplification.

A fundamental problem of the model is that the supply and demand curves to such a low extent offers realistic picture long-term elasticities of supply and demand

4.2.7 Fundamental critique of the model

The model fundamentally depends on the degree to which the supply and demand curves presented at Nord Pool gives a correct representation of the Nordic demand and supply of electricity. We have to be the most careful when changes are significant and long term in the model since the curves reflect short-term flexibility and long-term flexibility is likely to be quite different from the short-term. With regards to thermal power production things become difficult to predict. For instance one could believe that a higher price level would lead thermal production to go up. This is not necessarily so however. We have assumed a better integrated market and that means that average prices during summer in the thermally dominated markets are actually likely to go down. This will actually cause the system price to increase even more, not less as one might believe at first. The effects of more capacity to other markets increase the price however, which has the opposite effect on thermal production. Another important aspect to consider is that relatively small increases in trade have large impacts on prices. These fundamental problems with the model does not invalidate the discussion of the biases earlier, even though the bias might not be large on a given point estimate, this does not mean that the uncertainty with regards to the point estimate is small. The uncertainty with regards to the size of the biases is also likely to be significant and varying.

5. PART V

5.1 Conclusions

The goal of this thesis has been to describe the price level and structure effect that increased trade would have on the Nordic market and how this would affect the different actors in it. The general results of the model are pretty much in line with what could be expected and are certainly comparable to the results from other fundamentally based models. The model does however predict a much higher volatility in prices than predicted by other research. I believe however that this prediction is pretty robust for some of the predicted volatility. Even though most of the volatility is likely to be exaggerated, I believe the downward volatility to be less so. Generally the Nordic system price seems likely to be affected more by imports than by exports with regards to volatility since downward adjustment capacity in production is likely to be lower than upward adjustment capacity (on an hourly basis). This will be reflected by low night prices rather than with daily peaks. With increased renewable production this effect is likely to be even stronger since the steep part of the supply curve will move further to the right. With integration however the downside volatility of prices will be limited by the continental prices instead of by the marginal cost of intermittent production.

The estimated trade effects on price level variation is desirable since seasonal variation is reduced and the changing hydrological conditions in the Nordic countries will have a reduced effect on seasonal and yearly price level variations. The effect on the price level during the dry winter is approximately 4-5€ per MWh. This effect is probably only mildly exaggerated since trade might lead to lower water value in this part of the year, which would lead to an even lower price level. In addition most of the other biases stemming from the simplifications made are likely to not influence the results much during this time.

The model predicts that the effects during a Nordic price collapse are even greater than the effects during a dry winter. During the period with lowest prices in the Nordic the price level was raised with as much as 15€ for a period of a few weeks. This effect is probably only mildly exaggerated as well since the demand curve is quite inelastic when hydro capacity becomes a limiting factor for many hydro producers. The high jump in prices during November is most likely significantly exaggerated and based on underestimated capacity to adjust production upwards in the model.

The most controversial results are tied to the quite dramatic impact on the price structure. During the most extreme hours model results differed with as much as 60€ upwards compared to original results and 30€ downwards. Looking closer at these results it was concluded that the upward volatility is probably quite exaggerated compared to the downward volatility. In interpreting the most extreme results we have to keep in mind that the effect modelled is not simply the effect of one new interconnector. For some of the hours trade differed with as much as 5 000 MW compared to the original trade due to improvements in the intra-market grid, price effects are therefore likely to be extra strong in these hours. For the most extreme hours the simplifications made in the model are also likely to affect the model results the most, something that should urge us to treat these results with extra caution.

Over the entire year the prices increased with 1.8€/MWh on average. 2011 was a year with relatively high prices however and trade effects pulled in opposite direction in the first and second half of the year moderating the total effect on the year. The average effect on the price level was approximately 5€/MWh. All producer groups benefitted from the price increase, but hydro producers benefitted the most since short-term flexibility became more valuable. Consumers had to accept a slightly higher price level but did not adjust aggregate consumption. In general this thesis has focused more on the supply side than on the demand side. It is possible that demand side in the future can become important in balancing prices by becoming more sensitive to prices in the short-run. This will reduce the value of the Nordic hydropower.

In a longer perspective increased trade capacity might induce hydro producers to install more capacity in order to better take advantage of fluctuating prices. This would be reflected in more elastic supply curves on the upside. Capacity cannot be installed downwards however and hydro producers will at some point not be able to even out prices if thermal stays constant and especially if more intermittent production is included in the mix.

The model also predicts that the effects that trade will have on both volatility and price level will vary considerably over the year and it will depend on both reservoir levels and Nordic demand. The internal grid improvements will raise actual trade capacity with approximately the same size as the added 1 400MW of capacity, the internal grid improvements had an even greater effect however in some situations.

The marked model presented here can never replace the fundamental model approach as it suffers from many biases, especially when modelling further into the future and when modelling large increases. Looking at the model as a case study of the interesting year of 2011 we have nonetheless been able to gain some insight on how prices are formed in the Nordic market. Looking closely at different cases during this year of great variation it is possible to gain insight on how trade is likely to affect prices in the Nordic market differently depending on the time of the year, the reservoir level and also changing Nordic demand.

The Nordic market did not import a Continental price level or a continental price structure, even though the effects were quite strong for some parts of the year.

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6. APPENDIX

6.1 APPENDIX I: R code

(Not all R code is included only that for the main model, the rest can be provided by request)

```
#Dataset

MCP<-
read.table("/Users/matiaskroghboge/Documents/Master/JanuarJun2011.t
xt", header=TRUE, stringsAsFactors=FALSE, sep="\t", fill=T)

MCP2<-read.table("/Users/matiaskroghboge/Documents/Master/Sept-
dec2011.txt", header=TRUE, stringsAsFactors=FALSE, sep="\t",
fill=T)

MCP<-cbind(MCP,MCP2)

#number of hours

from=1

hour=8760

Consumersurplus<-1:hour
```

```
Producersurplus<-1:hour

Socialsurplus<-1:hour

Prices<-1:hour

Priced<-1:hour

Startdata<-14 #row at which data start

Buyblock<-3

Sellblock<-4

Column<-1:hour

lengthd<-1:hour

lengths<-1:hour

y<-matrix(nrow=length(MCP[,2]),ncol=hour)

x<-matrix(nrow=length(MCP[,2]),ncol=hour)

ys<-matrix(nrow=length(MCP[,2]),ncol=hour)

xs<-matrix(nrow=length(MCP[,2]),ncol=hour)

Volumeoriginald<-1:hour

Volumeoriginals<-1:hour

IGOD<-1:hour

IGOG<-1:hour

IGOP<-1:hour

IGOB<-1:hour

SPV<-array(dim=c(2000,2,hour))
```

```
DPV<-array(dim=c(1000,2,hour))


Dutchcap=700

Germancapu=4375

Germancapd=-4100

Polishcap=600

Britishcap=1400




partners<-4


Dutchd<-matrix(nrow=1000, ncol=hour)

Germand<-matrix(nrow=1000, ncol=hour)

Polishd<-matrix(nrow=1000, ncol=hour)

Britishd<-matrix(nrow=1000, ncol=hour)

Trade<-1:hour

z0<-1

z1<-1

i1<-1
```

```
DPe<-1:hour

DPi<-1:hour

GPe<-1:hour

GPi<-1:hour

PPe<-1:hour

PPi<-1:hour

BPe<-1:hour

BPi<-1:hour

TradeG<-1:hour

TradeD<-1:hour

TradeP<-1:hour

TradeB<-1:hour


StartBrit=8761



#hour loop


for(k in from:hour){
```

```
if(k<StartBrit){Britishcap=0}

Totcapu<-Dutchcap+Germancapu+Polishcap+Britishcap

Totcapd<-Germancapd-(Dutchcap+Polishcap+Britishcap)


#DPi er prisen man får ved import

DPi[k]<-DP[k]*1.04

DPe[k]<-DP[k]/1.04


GPi[k]<-GP2011[k]*1.03

GPe[k]<-GP2011[k]/1.03


PPi[k]<-PP[k]*1.03

PPe[k]<-PP[k]/1.03


#NB! BP januar til april er fra 2012

BPi[k]<-BP[k]*1.04

BPe[k]<-BP[k]/1.04
```

```
#Demand

Column[k]<-length(MCP[,2*k])-400

for(i in Startdata:Column[k]){

 if(MCP[i,2*k]==""){

 lengthd[k]<-(i-Startdata)/2}

 if(MCP[i,2*k]==""){break}}


Germand[,k]=0

Dutchd[,k]=0

Polishd[,k]=0

Britishd[,k]=0




for(i in 1:lengthd[k]){

 y[i,k]<-MCP[2*i+Startdata-2,2*k]}


for(i      in      1:lengthd[k]){x[i,k]<-as.numeric(MCP[2*i+Startdata-
1,2*k])+as.numeric(MCP[Buyblock,2*k])}


for(i in 1:lengthd[k]){
```

```
if(as.numeric(y[i,k])<=GPe[k]){Germand[i,k]<-Germancapu}

if(as.numeric(y[i,k])<GPe[k]){v1<-i+1}


if(as.numeric(y[i,k])>=GPi[k]){Germand[i,k]<-Germancapd}

if(as.numeric(y[i,k])<=GPi[k]){v2<-i+1}

}


for(i in 1:lengthd[k]){

if(as.numeric(y[i,k])<=DPe[k]){Dutchd[i,k]<-Dutchcap}

if(as.numeric(y[i,k])<DPe[k]){v3<-i+1}


if(as.numeric(y[i,k])>=DPi[k]){Dutchd[i,k]<--Dutchcap}

if(as.numeric(y[i,k])<=DPi[k]){v4<-i+1}

}


for(i in 1:lengthd[k]){

if(as.numeric(y[i,k])<=PPe[k]){Polishd[i,k]<-Polishcap}

if(as.numeric(y[i,k])<PPe[k]){v5<-i+1}


if(as.numeric(y[i,k])>=PPi[k]){Polishd[i,k]<--Polishcap}

if(as.numeric(y[i,k])<=PPi[k]){v6<-i+1}
```

```
}




for(i in 1:lengthd[k]){

if(as.numeric(y[i,k])<=BPe[k]){Britishd[i,k]<-Britishcap}

if(as.numeric(y[i,k])<BPe[k]){v7<-i+1}


if(as.numeric(y[i,k])>=BPi[k]){Britishd[i,k]<--Britishcap}

if(as.numeric(y[i,k])<=BPi[k]){v8<-i+1}

}


#Demand at export/import prices

GPed<-
 x[v1,k]+ifelse(GPe[k]<=PPe[k],Polishcap,0)+ifelse(GPe[k]<=DPe[k],Du
 tchcap,0)+ifelse(GPe[k]<=BPe[k],Britishcap,0)+ifelse(GPe[k]>=PPi[k]
 ,-Polishcap,0)+ifelse(GPe[k]>=DPi[k],-
 Dutchcap,0)+ifelse(GPe[k]>=BPi[k],-Britishcap,0)


GPid<-x[v2,k]+ifelse(GPi[k]>=PPi[k],-
 Polishcap,0)+ifelse(GPi[k]>=DPi[k],-
 Dutchcap,0)+ifelse(GPi[k]>=BPi[k],-
 Britishcap,0)+ifelse(GPi[k]<=PPe[k],Polishcap,0)+ifelse(GPi[k]<=DPe
```

```
[k],Dutchcap,0)+ifelse(GPi[k]<=BPe[k],Britishcap,0)


DPed<-
x[v3,k]+ifelse(DPe[k]<=PPe[k],Polishcap,0)+ifelse(DPe[k]<=GPe[k],Ge
rmancapu,0)+ifelse(DPe[k]<=BPe[k],Britishcap,0)+ifelse(DPe[k]>=PPi[
k],-
Polishcap,0)+ifelse(DPe[k]>=GPi[k],Germancapd,0)+ifelse(DPe[k]>=BPi
[k],-Britishcap,0)


DPid<-x[v4,k]+ifelse(DPi[k]>=PPi[k],-
Polishcap,0)+ifelse(DPi[k]>=GPi[k],Germancapd,0)+ifelse(DPi[k]>=BPi
[k],-
Britishcap,0)+ifelse(DPi[k]<=PPe[k],Polishcap,0)+ifelse(DPi[k]<=GPe
[k],Germancapu,0)+ifelse(DPi[k]<=BPe[k],Britishcap,0)



PPed<-
x[v5,k]+ifelse(PPe[k]<=DPe[k],Dutchcap,0)+ifelse(PPe[k]<=GPe[k],Ger
mancapu,0)+ifelse(PPe[k]<=BPe[k],Britishcap,0)+ifelse(PPe[k]>=DPi[k
],-
Dutchcap,0)+ifelse(PPe[k]>=GPi[k],Germancapd,0)+ifelse(PPe[k]>=BPi[
k],-Britishcap,0)


PPid<-x[v6,k]+ifelse(PPi[k]>=DPi[k],-
Dutchcap,0)+ifelse(PPi[k]>=GPi[k],Germancapd,0)+ifelse(PPi[k]>=BPi[
k],-
Britishcap,0)+ifelse(PPi[k]<=DPe[k],Dutchcap,0)+ifelse(PPi[k]<=GPe[
```

```
k],Germancapu,0)+ifelse(PPi[k]<=BPe[k],Britishcap,0)

BPed<-
x[v7,k]+ifelse(BPe[k]<=DPe[k],Dutchcap,0)+ifelse(BPe[k]<=GPe[k],Ger
mancapu,0)+ifelse(BPe[k]<=PPe[k],Polishcap,0)+ifelse(BPe[k]>=DPi[k]
,-
Dutchcap,0)+ifelse(BPe[k]>=GPi[k],Germancapd,0)+ifelse(BPe[k]>=PPi[
k],-Polishcap,0)

BPid<-x[v8,k]+ifelse(BPi[k]>=DPi[k],-
Dutchcap,0)+ifelse(BPi[k]>=GPi[k],Germancapd,0)+ifelse(BPi[k]>=PPi[
k],-
Polishcap,0)+ifelse(BPi[k]<=DPe[k],Dutchcap,0)+ifelse(BPi[k]<=GPe[k
],Germancapu,0)+ifelse(BPi[k]<=PPe[k],Polishcap,0)

zpv<-matrix(nrow=lengthd[k], ncol=2)

zpv[,2]<-as.numeric(y[1:lengthd[k],k])

zpv[,1]<-
as.numeric(x[1:lengthd[k],k])+as.numeric(Dutchd[1:lengthd[k],k])+as
.numeric(Germand[1:lengthd[k],k])+as.numeric(Polishd[1:lengthd[k],k
])+as.numeric(Britishd[1:lengthd[k],k])

new<-matrix(nrow=(partners*4),ncol=2)
```

```
new[1,2]<-GPe[k]

new[1,1]<-Germancapu+GPed

new[2,2]<-GPi[k]

new[2,1]<-Germancapd+GPid

new[3,2]<-DPe[k]

new[3,1]<-Dutchcap+DPed

new[4,2]<-DPi[k]

new[4,1]<--Dutchcap+DPid

new[5,2]<-GPe[k]+0.0001

new[5,1]<-GPed

new[6,2]<-GPi[k]-0.0001

new[6,1]<-GPid

new[7,2]<-DPe[k]+0.0001

new[7,1]<-DPed

new[8,2]<-DPi[k]-0.0001

new[8,1]<-DPid

new[9,2]<-PPe[k]

new[9,1]<-Polishcap+PPed

new[10,2]<-PPi[k]

new[10,1]<--Polishcap+PPid

new[11,2]<-PPe[k]+0.0001
```

```
new[11,1]<-PPed

new[12,2]<-PPi[k]-0.0001

new[12,1]<-PPid

new[13,2]<-BPe[k]

new[13,1]<-Britishcap+BPed

new[14,2]<-BPi[k]

new[14,1]<--Britishcap+BPid

new[15,2]<-BPe[k]+0.0001

new[15,1]<-BPed

new[16,2]<-BPi[k]-0.0001

new[16,1]<-BPid



zpv<-rbind(zpv,new)

zpv<-zpv[order(zpv[,2]),]



#original export is included in Demand
```

```
#supply

#NA counter

counter=0

for(l in Startdata:length(MCP[,2*k])){

 if(MCP[l,2*k]=="") counter=counter+1}


lengths[k]<-(length(MCP[,2*k])-2*lengthd[k]-counter-Startdata+1)/2


for(i in 1:lengths[k]){

 ys[i,k]<-MCP[2*i+2*lengthd[k]+Startdata-1,2*k]}


for(i                    in                    1:lengths[k]){xs[i,k]<-
 as.numeric(MCP[2*i+2*lengthd[k]+Startdata,2*k])+as.numeric(MCP[Sell
 block,2*k])}


spv<-matrix(nrow=lengths[k], ncol=2)


spv[,2]<-as.numeric(ys[1:lengths[k],k])

spv[,1]<-as.numeric(xs[1:lengths[k],k])
```

```
#Find Volumes and Prices

P=0

for (i in 1:lengths[k]) {for(j in 1:lengthd[k]){

 if(as.numeric(spv[(lengths[k]-i),1])<=as.numeric(zpv[j,1])){

    if(as.numeric(spv[(lengths[k]-i),2])<=as.numeric(zpv[j,2])){

        i1<-(lengths[k]-i)+1

        z0<-j


        for(z in 1:(lengthd[k]-j)){

            if(as.numeric(spv[i1,2])<as.numeric(zpv[(lengthd[k]-
 z),2])){z1<-lengthd[k]-z}}



        ifelse(as.numeric(zpv[z1,1])>=as.numeric(spv[(lengths[k]-
 i),1]),V<-zpv[z1,1] ,V<-spv[(i1-1),1])


    if(as.numeric(zpv[z0,2])==as.numeric(spv[i1,2])){V=as.numeric(z
 pv[z0,1])}

        ifelse(as.numeric(zpv[z1,1])>=as.numeric(spv[(lengths[k]-
 i),1]),n<-z1, n<-z0)

        ifelse(V==zpv[z1,1], P<-spv[i1,2],P<-zpv[z0,2])           }}}
```

```
        if(P>0){break}}



for(i in 1:lengthd[k]){

 if(as.numeric(y[i,k])<P){VD<-as.numeric(x[(i+1),k])}}






Trade[k]<-V-VD

if(Trade[k]<=Totcapd){Trade[k]<-Totcapd}

if(Trade[k]>=Totcapu){Trade[k]<-Totcapu}


Volumeoriginald[k]<-V

Volumeoriginals[k]<-V


Prices[k]<-P

Priced[k]<-P

if(k<StartBrit){TradeB[k]=0}


if(P>GPi[k]){TradeG[k]<-Germancapd}
```

```
if(P<GPe[k]){TradeG[k]<-Germancapu}

if(GPe[k]<P & P<GPi[k]){TradeG[k]<-0}


if(P>DPi[k]){TradeD[k]<--Dutchcap}

if(P<DPe[k]){TradeD[k]<-Dutchcap}

if(DPe[k]<P & P<DPi[k]){TradeD[k]<-0}


if(P>PPi[k]){TradeP[k]<--Polishcap}

if(P<PPe[k]){TradeP[k]<-Polishcap}

if(PPe[k]<P & P<PPi[k]){TradeP[k]<-0}


if(P>BPi[k]){TradeB[k]<--Britishcap}

if(P<BPe[k]){TradeB[k]<-Britishcap}

if(BPe[k]<P & P<BPi[k]){TradeB[k]<-0}


if(P==GPe[k]){TradeG[k]<-Trade[k]-
 sum(TradeD[k]+TradeP[k]+TradeB[k])}

if(P==GPi[k]-0.0001){TradeG[k]<-Trade[k]-
 sum(TradeD[k]+TradeP[k]+TradeB[k])}
```

```
if(P==DPe[k]){TradeD[k]<-Trade[k]-
 sum(TradeG[k]+TradeP[k]+TradeB[k])}

if(P==DPi[k]-0.0001){TradeD[k]<-Trade[k]-
 sum(TradeG[k]+TradeP[k]+TradeB[k])}


if(P==PPe[k]){TradeP[k]<-Trade[k]-
 sum(TradeG[k]+TradeD[k]+TradeB[k])}

if(P==PPi[k]-0.0001){TradeP[k]<-Trade[k]-
 sum(TradeG[k]+TradeD[k]+TradeB[k])}


if(P==BPe[k]){TradeB[k]<-Trade[k]-
 sum(TradeG[k]+TradeD[k]+TradeP[k])}

if(P==BPi[k]-0.0001){TradeB[k]<-Trade[k]-
 sum(TradeG[k]+TradeD[k]+TradeP[k])}


Trade[k]<-TradeD[k]+TradeG[k]+TradeB[k]+TradeP[k]


IGOD[k]=0

IGOG[k]=0

IGOP[k]=0

IGOB[k]=0
```

```
if(P>=GPi[k]){IGOG[k]<--TradeG[k]*(P-GPi[k])}

if(P<=GPe[k]){IGOG[k]<-TradeG[k]*(GPe[k]-P)}


if(P>=DPi[k]){IGOD[k]<--TradeD[k]*(P-DPi[k])}

if(P<=DPe[k]){IGOD[k]<-TradeD[k]*(DPe[k]-P)}


if(P>=PPi[k]){IGOP[k]<--TradeP[k]*(P-PPi[k])}

if(P<=PPe[k]){IGOP[k]<-TradeP[k]*(PPe[k]-P)}


if(P>=BPi[k]){IGOP[k]<--TradeB[k]*(P-BPi[k])}

if(P<=BPe[k]){IGOP[k]<-TradeB[k]*(BPe[k]-P)}



SPV[1:lengths[k],,k]<-spv

DPV[1:(lengthd[k]+partners*4),,k]<-zpv

}



OriginalTrade<-1:8760

for(i in 1:8760){

 OriginalTrade[i]<-as.numeric(MCP[5,2*i])}
```

```
t=7699

test<-matrix(ncol=2, nrow=lengthd[t])

test[,1]<-x[1:lengthd[t],t]

test[,2]<-y[1:lengthd[t],t]



plot(zpv,type="s",col="red", xlim=c(15000,40000), ylim=c(0,100))

lines(test,type="s",col="green")

lines(spv, type="s", col="red")


gline<-1:1000000

gline[1:100000]=GP2011[t]

pline<-1:1000000

pline[1:100000]=PP[t]

dline<-1:1000000

dline[1:100000]=DP[t]

nline<-1:1000000

nline[1:100000]=Prices[t]

oline<-1:1000000

oline[1:100000]=sys[t]
```

```
lines(gline, type="l", col="red")

lines(dline, type="l", col="orange")

lines(pline, type="l", col="yellow")

lines(oline, type="l", col="green")

lines(nline, type="l", col="blue")


float24sys<-1:(length(sys)-24)

for(i in 24:8760){

   float24sys[(i-23)]<-mean(sys[(i-23):i])}


float24Prices<-1:(length(Prices)-24)

for(i in 24:8760){

   float24Prices[(i-23)]<-mean(Prices[(i-23):i])}


sumTrade<-1:8760
```

```
for(i in 1:8760){

 sumTrade[i]<-sum(na.omit(Trade[1:i]))}


sumOriginalTrade<-1:8760


for(i in 1:8760){

 sumOriginalTrade[i]<-sum(na.omit(OriginalTrade[1:i]))}


extraTrade<-sumTrade+sumOriginalTrade


#consistency check


consistency=0

for(i in 1:k){

 if(Trade[i]!=TradeD[i]+TradeG[i]+TradeP[i]){consistency=consistency
 +1}}


Test=TradeD[700:740]+TradeG[700:740]+TradeP[700:740]


float168Prices<-1:(8760-168)

for(i in 1:8592){
```

```
 float168Prices[i]<-mean(na.omit(Prices[i:(167+i)]))}


float168sys<-1:(8760-168)

for(i in 1:8592){

 float168sys[i]<-mean(na.omit(sys[i:(167+i)]))}


diff<-Prices-sys


mdiff<-1:8592

for(i in 1:8592){

 mdiff[i]<-mean(na.omit(diff[i:(167+i)]))}





save.image(file="/Users/matiaskroghboge/Documents/Master/Modell2.Rd
 a


ta")
```

6.2 APPENDIX II: Producer effects

The calculations presented are not an attempt to produce exact estimations on the benefit for the different producers. They should rather be considered a ballpark estimate and an illustration of the direction of the effects.

When calculating the Hydro production I have used estimates on both real production and modeled production. Real production data are not available from Nord Pool and even though they might be available from TSO databases I have chosen to estimate the production since the modeled production is not possible to separated production in a precise manner. The interesting aspect is the change and not being able to give a precise estimate of realized income for hydro producers. When using estimates the error in the model and the real estimates will suffer from the same simplification and thus make them more comparable.

I have estimated hydro production based on the available weekly thermal data and hourly production at Nord Pool. The estimation has simply been to subtract thermal production times Nord Pool spot share of trade from Nord Pool spot volume – Imports. As the Nord Pool spot share I used the percentage reported by Nord Pool at 73% which is slightly lower than my own estimate. This gives a hydro production close to exactly equal to real production when summing over the year. Hydro production is hydro production at Nord Pool however and not total in the calculations.

I have assumed that thermal production stays constant. For thermal production I have used total production, which is the number available. Therefore thermal production and hydro production numbers are not comparable in size.

Since all thermal stays constant all changes in volume are changes in hydro production.

These hourly production figures are then multiplied by the relevant price for that hour. Summing up these numbers we have the total value of the relevant production. If we divide this number by total production we have the average price received on that production.

6.3 APPENDIX III: Data sets

MCP data downloaded from Nord Pool homepage under historical data, system price curves. They are available on a daily basis and represent the historical bid and ask curves for the Nordic market, trade excluded.

German prices for 2011 are downloaded from the European power exchange the EEX.

Polish prices are downloaded from the Polish power exchange the POLPX.

Daily exchange rates for Polish Zloty vs. Euro are downloaded from the European central bank.

Dutch power prices have been given to me by Vlad Kaltenieks at the APX Endex power exchange.

Real production data for different sources of supply for the Nordic countries are gathered by Nordel but provided to me through Kristina Remec at Nord Pool.

Historical reservoir levels, spot volumes and regulating market volumes are available at the Nord Pool home page

Most datasets can be made available by request. The total amount of datasets amounts to approximately 400MB worth of data material.