Master Thesis

An Analysis of Basis Risk in the Nordic Electricity Market and How it Can Be Hedged

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Abstract

In the Nordic electricity market, electricity producers face the risk of substantial price variations across time and space. The prices across different geographical areas can differ due to transmission congestion. To hedge against the risk of price variations across time and space the market participants can use forward or future contracts and Contracts for Difference (CfDs), which are listed at Nord Pool. CfDs are forward contracts on the spread between a particular area price and the system price. This paper provides an analysis of the basis risk in the Nordic electricity market, how the electricity producers can hedge the risk of locational and time-varying price differences, and how effective the hedging vehicles being used are. My analysis of the spread between the area prices and system price from 2000 to 2008, and the frequency of transmission congestion underlines the need of risk management for market participants. I also analyse the pricing of CfDs and whether these contracts contains risk premia. I find that most CfDs contain a risk premium; however, the sign and magnitude of the risk premium differ substantially between areas and also between delivery periods. In order to illustrate how an electricity producer can hedge the basis risk he is facing, I constructed a case. The case illustrates that an electricity producer during 2007 and 2008 could significantly reduce his risk by taking certain positions in the financial market.

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Chapter I: Introduction

The deregulation of the Norwegian electricity market in 1990 marked the beginning of a new electricity regime in the Nordic countries. Before the deregulation the Norwegian electricity producers provided electricity to consumers at fixed prices set yearly by the local governments. As a result of the deregulation, the electricity producers had to adapt to a changing environment with increasing competition towards the consumers and with more volatile electricity prices. The electricity producers and consumers can sell and purchase electricity at the Nordic electricity exchange, Nord Pool. Nord Pool has developed into an advanced functioning electricity exchange with spot trading and a financial market. According to Marckhoff and Wimschulte (2009), the liquidity in the trading of spot and financial products is still relatively thin compared to well-established commodity markets, such as those for crude oil and gold. Electricity prices are known for being highly volatile, partly due to the fact that electricity is non-storable so that there are limited options to dampen the effects of supply and demand shocks. The volatility of the electricity prices creates a substantial risk for the market participants. The financial market, however, provides the risk managers with tools they can use to hedge the risk their companies are facing.

Forward and futures contracts provide the market participants with an opportunity to hedge positions in the electricity market. However, forward and futures contracts use the system price as a reference price. The actual price for the electricity, which the market participants receives or purchase, is dependent on the current area price. The area prices depend on supply and demand in each market and the transmission capacities between the areas. The area prices can differ from the system price due to transmission congestion between areas. Therefore, the forward and futures contracts do not provide the market participants with the opportunity to construct a perfect hedge. The size of the locational prices spreads can vary substantially across time and space, and they have created the need for an additional hedging vehicle.

In order to manage the risk of locational price spreads Nord Pool constructed what is essentially a forward contract with the spread between an area price and the system price as the reference price. These contracts are termed Contracts for Difference (CfD). The CfDs are cash settled and they cover a specific delivery period. The first CfD contracts were listed on Nord Pool with delivery in 2001. Since then the market participants have had the option to hedge their risks in a better way by using forwards with the combination of CfDs. However, to create liquidity, the CfD market relies on a sufficient number of market participants on both the supply and demand side. If the number of participants on either side has a larger number of participants there is reason to believe that there would be a risk premium in the CfD price. Kristiansen (2004a), Kristiansen (2004b), and Marckhoff and Wimschulte (2009) analyse the pricing of CfDs at Nord Pool. They find evidence of a positive risk premium for most of the CfDs; however, the risk premia vary substantially across areas and delivery period. My hypothesis is that the hydropower producers in Norway are risk-averse economic agents. The electricity producers can hedge with forwards contracts and CfDs in order to protect themselves against the high volatility and basis risk present in the Nordic electricity market. The risk averseness of the electricity producers could be due to the fact that many of the electricity producers are owned by local governments, who base some of their income on dividends from their electricity companies, and that the hydro plants are characterised by high initial investments. Agder Energi, with headquarter in Kristiansand is one example. As a result of the risk-averseness the electricity producers in the Oslo area would have to pay a risk premium to hedge with CfD contracts.

My findings show that there are frequent and often substantial variations between the area prices and the system price. These spreads differ across space and time. Also, I analyse the pricing of CfDs and find that they on average contain risk premia. Because of that, the CfDs cannot be considered to be unbiased predictors of the future price spreads between the area prices and the system price. Lastly, I construct a case to analyse how an electricity producer can hedge the risk that he is facing in the Nordic electricity market. I find that the volatility of the cash-flow and the average cash-flow may vary significantly depending on the chosen hedging strategy.

The remainder of the thesis is organized as follows. In Chapter 2, the Nordic Electricity market, Nord Pool, is closer described. Special attention is given to the price setting in the spot market and in the financial market. Chapter 3 will be devoted to theory about risk management, how to assess the risk in the electricity markets, and possible ways to hedge this risk. In Chapter 4, there is first an overview of the data used in this paper. Then, I will look at the different electricity sources in the Nordic countries and the impact they have on transmission and prices. Also, I will investigate the need for hedging by analyzing the differences between the area prices and system price. At the end of this chapter I analyse the CfD prices and whether there are risk premia in these prices. Chapter 6 demonstrates the need for hedging of an electricity producer, and the possible ways to do that, by creating a case regarding a fictional electricity producer. Chapter 6 and 7 contains conclusion and bibliography, respectively.

Chapter II: The Nordic Electricity Market

2.1 History

The Nordic Electricity market, as we see it today, started with Norway's deregulation of its power market in 1990 through The Energy Act (Nord Pool History, 2009). This formed the basis for deregulation in the other Nordic countries. In 1996, Sweden joined the Nord Pool system; it became the world's first multinational exchange for trade in electricity contracts. Finland joined the electricity exchange in 1998 and the EL-EX power exchange in Helsinki entered into an agreement to represent Nord Pool. The Nordic electricity market became fully integrated when West Denmark and East Denmark joined Nord Pool in 1999 and 2000. Nord Pool has been steadily developing since the creation of its predecessor (Statnett Marked) in 1990. Today, the exchange operates three main markets and offers clearing and consulting services (Nord Pool, 2009). The three main markets of operation are the physical market, derivatives, and emissions. The derivatives and emissions market are both financial markets. The physical markets consist of Elspot, Elbas and Gas. A closer description of the markets will be given below; however, most attention will be given to the Elspot and the financial market since those are the most relevant markets for this thesis.

2.2 The Elspot market

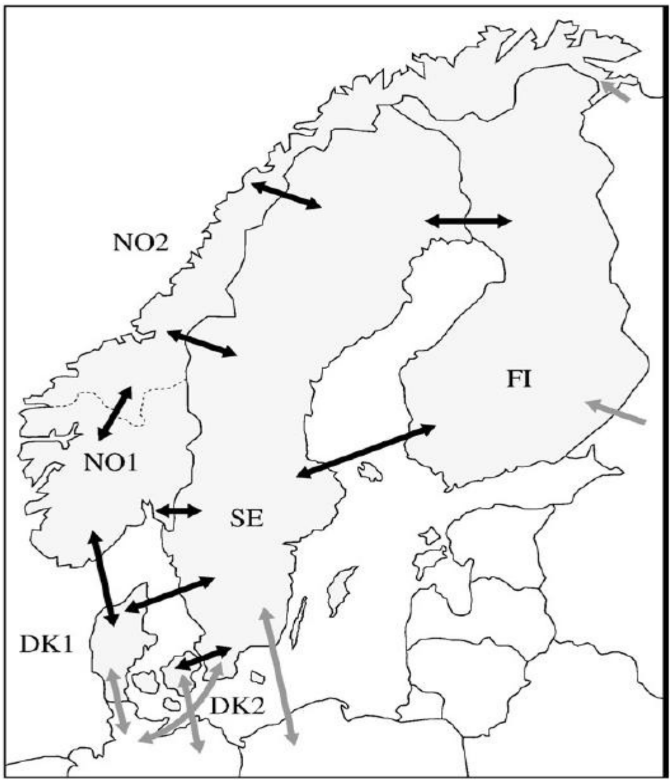
Following Nord Pool Elspot Market (2009), electricity contracts on the Elspot market are traded daily for physical delivery during the next day's 24-hour period. The price calculation is based on the balance between the market's supply and demand curves. There are three different bidding types for hourly contracts: hourly bids, block bids and flexible hourly bids that cover some or all of the 24 hours of the next day. The trading method is auction based with implicit auctions on the interconnections between the bidding areas. At the interconnections between the Nordic countries and within Norway, price mechanisms are used to relieve bottlenecks (congestion management) by creating different Elspot area prices. Within the Elspot areas Sweden, Finland, and Denmark, grid congestion is managed by counter-trade purchases based on bids from generators. The flow of power is adjusted to the available trading capacity given by the Nordic Transmission System Operators (TSOs). All trading capacity between the bidding areas is dedicated to Nord Pool Spot for implicit auction. This is an advantage for the market since the capacity is then available to all participants on equal terms.

The Elspot market is actually a day-ahead market, but is termed the “spot market” by the market participants. The Elbas market is the closest to, what is normally thought of as, a spot market at the Nordic Electricity Exchange. According to Nord Pool’s Annual Report 2008, the Elspot market had a turnover in 2007 and 2008 of 297.6 and 290.6 TWh, respectively. If we compare that to the volume of the Elbas market, 1.8 and 1.6 TWh in 2007 and 2008, we see that the Elspot market is by far the most important market.

2.2.1 Congestion management and bidding areas

In order to handle grid congestions the Nordic exchange area is geographically divided into bidding areas (Nord Pool Bidding, 2009). The participants must place their bids according to where their production or consumption is physically connected in the Nordic grid. Thus the transmission capacity between each bidding area is auctioned implicit in the Elspot price calculation. Grid congestion within a bidding area is managed by the TSO. The bidding areas are: Sweden (SE), Finland (FI), German area KONTEK (KT), West Denmark (DK1), and East Denmark (DK2). In Norway, the Norwegian TSO, Statnett, determines how to split the grid. The grid is usually divided into two bidding areas (NO1 and NO2), but three or more areas are possible depending on the circumstances.

Figure 2.1



Source: Marckhoff and Wimschulte (2009)

Figure 2.1 illustrates the main market areas and interconnections in the Nordic market in 2009. The black arrows and gray arrows indicate the main interconnections between the areas and to countries outside the Nordic area respectively. However, Figure 2.1 does not give the complete picture of the interconnections in the Nordic market. In 2008 an electricity transmission cable between the Netherlands and the South of Norway was completed (Statnett, 2009). The cable has a capacity of 2.1 TWh.

2.2.2 Bid types

In the Elspot Market all volumes are stated in MW per hour (MWh). In bidding, purchases are designated as positive numbers and sales as negative numbers. There are three types of bids available; hourly bid, block bid and flexible hourly bid (Nord Pool Bid Types, 2009).

The **hourly bid** is the basic type of market order. Each participant selects the range of price steps for the bid individually. The simplest bid is a **price independent bid** for all hours. This means that the participant will receive a schedule of deliveries equal to the specified volume for all hours, regardless of the price level within the range. The participants can also submit **price dependent bids**.

The **block bid** is an aggregated bid for several hours (minimum 4 hours), with a fixed price and volume throughout these hours. Inflexible production, consumption, and contracts can be handled efficiently with block contracts. A block bid must be accepted in its entirety. The block bid price is compared with the average Elspot price for the hours to which the bid applies. A block bid is accepted if the bid price of a sales block is lower than the average Elspot area price, or if the bid price of a purchase block is higher than the average Elspot area price. It is also possible to define links between block bids so that the acceptance of one block bid is dependent on the acceptance of another block bid.

The **flexible hourly bid** is a sales bid for a single hour with a fixed price and volume. The hour is not specified so the bid will be accepted in the hour with the highest price in the calculation, given that the price is higher than the limit set in the bid.

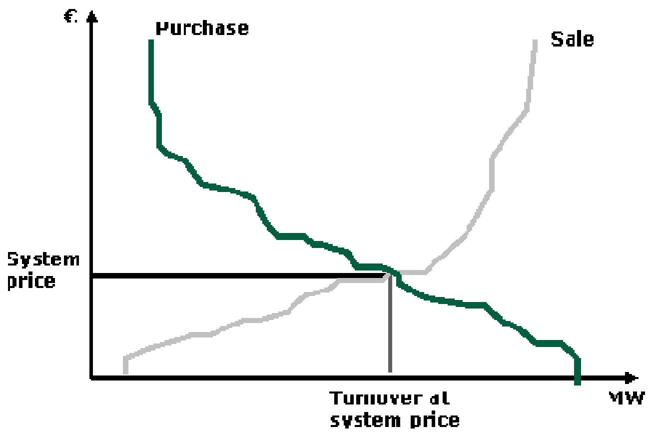
2.2.3 Price Calculation

The Elspot prices are determined through auction trade for each delivery hour. The system price and the area prices for the next day are calculated after the bids from the participants have been received at 12:00 (Nord Pool Bidding, 2009).

System price:

The **system price** can also be called the unconstrained market clearing price because it does not take into account the trading capacities between the bidding areas (Nord Pool System Price, 2009). The system price for each hour is determined by the intersection of the aggregated supply and demand curves which are representing all bids and offers from the entire Nordic region. The influence of the German bidding area KONTEK on the Nordic system price is limited to the available trading capacity to and from the adjoining bidding areas DK1 and DK2. The majority of the standard financial contracts traded in the Nordic region refer to the system price. Figure 2.2 illustrates how the system price is determined in the intersection between supply and demand.

Figure 2.2 – System price

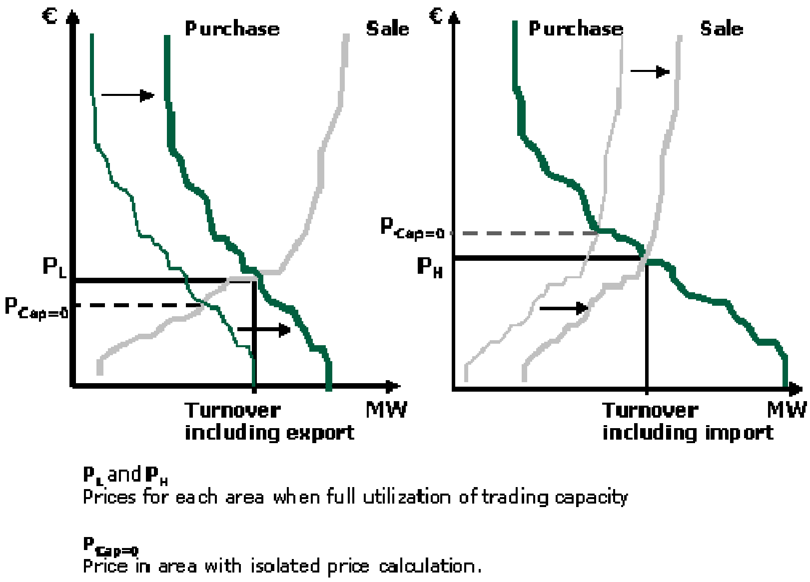


Source: Nord Pool System Price (2009)

Area price:

According to Nord Pool Price Area (2009), **area prices** are calculated if the flow of electricity between the bidding areas exceeds the trading capacity. The participant's bids, in the bidding areas on each side of the congestion, are aggregated into supply and demand curves in the same fashion as in the system price calculation. A volume corresponding to the trading capacity of the constrained connection is added as a price independent purchase in the surplus area and a price independent sale in the deficit area. In the deficit area the sale will give a parallel shift of the supply curve while in the surplus area the additional purchase will give a parallel shift of the demand curve. This will lead to a new equilibrium point in both price areas. In this situation the flow of power will always go from the lower price (surplus) area to the higher price (deficit) area. Figure 2.3 illustrates the price setting in case of congestion.

Figure 2.3 – Area price



Source: Nord Pool Price Area (2009)

2.3 The Elbas Market at Nord Pool

The Elbas Market is there to cover the immediate needs of the market players in the electricity market (Nord Pool Elbas, 2009). The Elbas market is open around the clock everyday of the year and it enables continuous trading 24 hours a day, 7 days a week. The time span between the day's Elspot price-fixing and the actual delivery hour of the concluded contracts can be 36 hours at the most. Because of changing consumption and production situations a market player may need to trade during these 36 hours. This is why the Elbas market exists; it allows the market players to trade one-hour long power contracts up to one hour prior to delivery.

The Elbas market is open in Norway, Finland, Sweden, Denmark, and Germany. The participants are electricity producers, distributors, industries and brokers. An essential point in the Elbas market is managing the trading capacity between the bidding areas. After a cross border trade the capacity between the bidding areas are automatically updated. If bottlenecks occur Automated Market Splitting divide the areas dynamically.

2.4 Gas

Nord Pool Gas was established as an independent company in 2008 with the first trading day on March 4th (Nord Pool Gas, 2009). The gas exchange organizes physical trade of natural gas. The products offered are day contracts and a following-month contract.

Trading at Nord Pool Gas is based on continuous trading and is performed electronically through the internet. This contributes to the development and dynamic of the gas market.

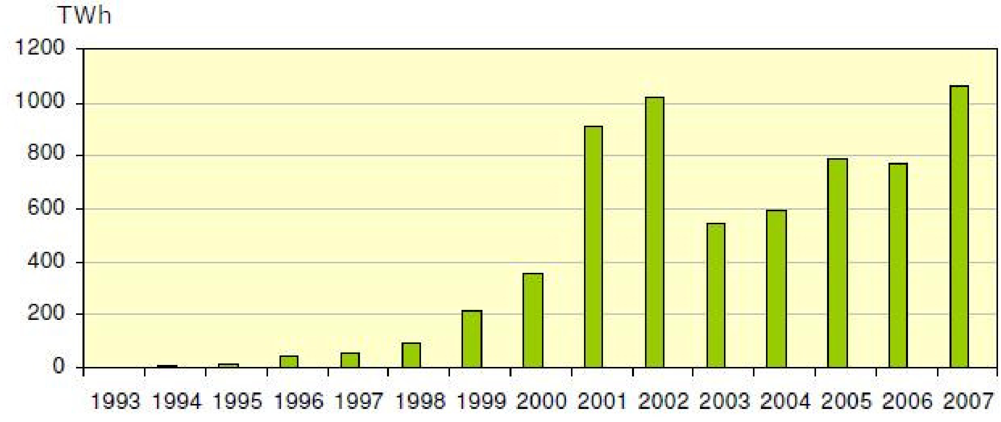
2.5 The Financial Market

The source of the background information regarding the financial market is Trade at Nord Pool ASA's Financial Market (2008).

There is no physical delivery of financial electricity contracts at Nord Pool, only cash settlement. The financial contracts have been designed to satisfy the needs of participants like the producers and retailers, who use the products as risk management tools, and traders who profit from volatility in the electricity market. The exchange members can trade the financial products electronically or via telephone to the financial desk at Nord Pool. The financial products are sometimes adjusted to the needs of the market participants in order to increase the liquidity of the market.

Figure 2.4 describes the total volume of financial contracts traded at Nord Pool from 1993 to 2007. We can see that the volume has increased significantly since 1994. The volume more than doubled from 2000 to 2001, but then shrank from 2002 to 2003. According to Nord Pool's Annual Report 2008 the volume increased 36% from 2007 to 2008 resulting in a turnover for the financial market of over 1400 TWh in 2008. In October 2008, NASDAQ OMX acquired Nord Pool's international power derivatives, the carbon products, the clearing business and the consultancy services from Nord Pool ASA. The acquisition is expected to increase the liquidity and efficiency of the exchange, and introduce new products to the exchange.

Figure 2.4 – Volume financial contracts at Nord Pool



Source: Trade at Nord Pool ASA's Financial Market (2008) page 23.

2.5.1 Futures contracts

Nord Pool has listed both base load day and week **future contracts** for trading. The day contract has a period of 24 hours and the week contract a period of 7 days. The Nordic week contracts are listed with 6 consecutive contracts in a continuous rolling cycle. Nord Pool also lists futures peak contracts for the 5 nearest weeks in the Nordic market and for the 4 nearest weeks for trade in Germany and The Netherlands. Settlement of futures contracts involves both a daily mark-to-market settlement and a final spot reference cash settlement, after the contract reaches its due date.

2.5.2 Forward contracts

The previous **forward contract** structure at Nord Pool listed the contracts for three seasons: Winter 1, Summer, and Winter 2; and Year forward contracts. The new product structure lists base load contracts for each cale0ndar Month, Quarter and Year contracts. Nordic month contracts are listed on a 6 month continuous rolling basis, and they are not subject to splitting. Quarter contracts are split into month contracts and Year contracts are split into quarter contracts in accordance with product specification rules. Year contracts are listed five years ahead.

Nordic Peak products, which cover the time period 08:00 to 20:00 from Monday to Friday (including national holidays), are listed for the nearest 5 weeks, 2 months, 3 quarters, and 1 year.

In the trading period prior to the due date for all these forward products, there is no mark-to-market settlement. Throughout the delivery period, settlement is carried out in the same way as for futures. Both futures and forward contracts are settled with cash. In this paper I consider futures and forward contracts to be indistinguishable.

2.5.3 Contracts for Difference (CfD)

The reference price for the Nordic forward and futures contracts at Nord Pool is the system price. As mentioned above the actual cost of buying or selling energy can differ from the system price due to different area prices. It is only possible to get a perfect hedge by using forwards and futures when there is no grid congestion, i.e. the area price equals the system price. In the analysis, the occurrence of grid congestion will be investigated. Hedging in futures or forward contracts implies a **basis risk** equal to the difference between the area price at the member's physical location and the system price. In this paper I use the difference between the area price and the system price as a proxy for the basis risk.

Contracts for Difference are essentially forward contracts which refer to the difference between an area price P_t^A and the system spot price P_t^S over the delivery period. CfDs could be replicated by a system price forward and an area price forward. However, the idea of an area price forward was rejected by Nord Pool because it would split the total liquidity among several products. Instead of introducing area forwards Nord Pool introduced CfDs. I follow Marckhoff and Wimschulte's (2009) definition of a CfD's payoff; however, I modify it to take into account the price of the CfD contract (C^{CfD}). Also, I include P^S in the function argument.

$$CfD\left(P^A, P^S, T_1, T_2\right) = \frac{1}{T_2 - T_1} \sum_{t=T_1}^{T_2} \left(P_t^A - P_t^S\right) - C^{CfD} \tag{1}$$

Where T_1 and T_2 denote the start and end dates of the delivery period. Being long in a CfD contract during the delivery period gives you the same payoff as receiving the area spot price while paying the system price and the CfD price, everyday. A CfD contract can be negative, positive, or zero since they refer to the expectations of the future area and system price. Generally the electricity producers take short positions in CfDs while retailers take long positions. The market price of a CfD during the trading period reflects the market's prediction of the price spread during the delivery period. CfDs trade at positive (negative) prices when the market expects a specific area price to be higher (lower) than the System Price.

CfDs were introduced to provide the possibility of a perfect hedge even when the markets are divided into two or more price areas. To create a perfect hedge using CfDs the following three steps must be followed (Kristiansen, 2004b):

1. Hedge the required volume using forward contracts.
2. Hedge any price difference, for the same period and volume, using CfDs.
3. Complete the hedge by buying or selling energy in the area where the member is located.

Nord Pool provides trading in CfDs for the following areas:

CfD name and reference area	CfD definition
Norway	CfD^{NO1} = Oslo area price minus system price
Sweden	CfD^{SE} = Stockholm area price minus system price
Finland	CfD^{FI} = Helsinki area price minus system price
Denmark West	CfD^{DK1} = Aarhus area price minus system price
Denmark East	CfD^{DK2} = Copenhagen area price minus system price
SYGER	CfD^{SYGER} = Phelix Price Germany area price minus system price

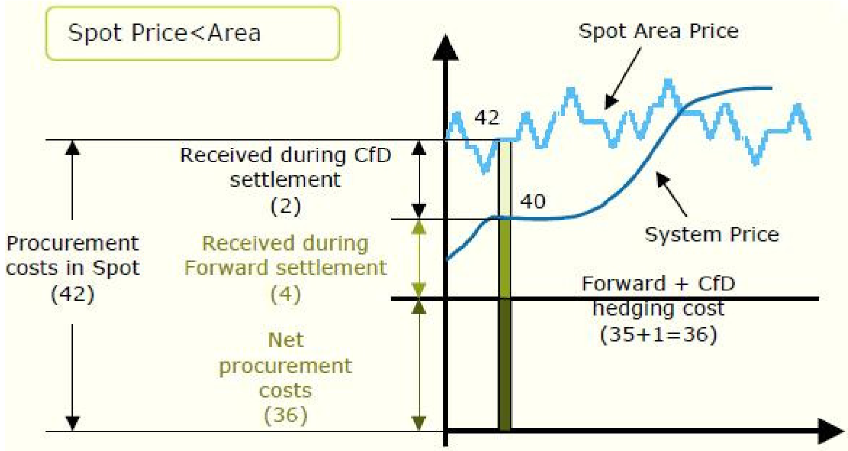
The following example illustrates a perfect hedge for an electricity purchaser in the NO1 area during one specific hour. The hedger followed the three step procedure mentioned above. As illustrated in Figure 2.1, the market participant has purchased a forward contract at a price of 35 EUR/MWh and a NO1 CfD at a cost of 1 EUR/MWh. The forward contract and CfD is used to hedge the system price and the CfD^{NO1} spread respectively. The total hedge procurement cost is therefore 36 EUR/MWh. If the electricity purchaser has to pay a higher (lower) price than 36 EUR/MWh for 1 MWh of electricity, the forward and CfD will ensure that he gets compensated with (have to pay) the difference. Therefore, the procurement cost will always be 36 EUR/MWh for the duration of the contracts.

During the selected hour the system price is 40 EUR/MWh and the area price is 42 EUR/MWh. For our electricity purchaser the procurement cost in the spot market is therefore 42 EUR/MWh. Table 2.1 shows how the hedging positions compensates the purchaser for the high NO1 area price.

Table 2.1 – Overview hedging example

Total cost per 1 MWh during the selected hour:		
Purchase 1 MWh at the NO1 area price:		-42EUR/MWh
Payoff forward contract:	40-35	5EUR/MWh
Payoff NO1 CfD:	42-40-1	1EUR/MWh
Total cost per 1 MWh during the selected hour:		-36EUR/MWh

Figure 2.5 – Illustration hedging example



Source: Trade at Nord Pool ASA's Financial Market (2008) page 13.

Nord Pool introduced the first CfDs in November 2000 with the first trading day on the 17th in the same month. The minimum contract size for a CfD is 1 MW. The first CfDs were season contracts for the areas of Aarhus (DK1), Oslo (NO1), Helsinki (FI), and Stockholm (SE). Season contracts for Copenhagen (DK2) and year contracts for all areas were introduced in 2001 and 2002. The delivery period for the season CfDs are January-April (Winter 1), May-September (Summer), and October-December (Winter 2). In order to meet international standards, Nord Pool switched from seasonal to quarterly contracts in 2006. According to data provided by Nord Pool, CfDs for the next two months, three quarters, and one year are tradable. From 2006, CfDs with one year delivery period could be traded three years ahead. When it comes to settlement, only month CfDs are cash settled while Quarter and Year contracts are replaced by a corresponding position in Month or Quarter CfDs. Trading is not allowed during the delivery period. Market participants can also enter into CfDs in the Over the Counter market; here the product specifications can differ from those listed at Nord Pool. Month CfDs were introduced in 2004 for all areas except DK1.

2.5.4 Option contracts

An option is the right to buy or sell an underlying contract at a predetermined price at a predefined date in the future. The option contracts at Nord Pool can only be exercised at the exercise date (European style option). Option contracts to buy are termed **call options**, and option contracts to sell are termed **put options**.

2.5.5 European Union allowances (EUA) and Certified Emission Reduction (CER)

The EU Emission Trading Scheme is introduced across Europe to handle emissions of carbon dioxide and other greenhouse gases, in order to counter the threat of climate change. Nord Pool offers forward contracts and a spot market for EUA products. The minimum contract size is 1000 ton CO_2.

A CER contract is the name for an emission credit obtained through the clean development mechanism (CDM), which is implemented by the United Nations. The recipient has achieved a reduction corresponding to one tonne of CO_2 or carbon equivalent greenhouse gas in a developing country. The contract enables European companies to comply with the purposes under the EU ETS and governments to fulfil their obligations under the Kyoto protocol.

2.6 Factors affecting the Nordic electricity price

The price of electricity is, as we know, dependent on supply and demand. But, the price is also dependent on the expectations the different participants have towards factors that will affect the price. According to Statkraft (2009), it is expected that the electricity consumption in Norway will increase with 1 – 1.5 TWh per year. Over the last 10 years the consumption of electricity has increased five times more than the production capacity.

The following factors can have an impact on the electricity price (Statkraft, 2009). The level of precipitation and melting water has a significant impact on the electricity prices in the Nordic market because a big part of it is served by hydro-power. Houses in the Nordic countries are often heated with electricity. As a result, the weather (temperature) impacts the price of electricity. Also, the general economic development in the region and in the world will impact the demand and supply of electricity. If the price of coal increases, the cost of producing electricity at the coal-plants will increase. This could reduce the supply of energy and increase the price of electricity. The price of CO_2 emission contracts can also impact the profitability of the coal plants. In the same way as with coal, the price of gas can impact the electricity price. The Nordic market is linked with Russia, the Netherlands, Germany and Poland. Depending on the prices in the different areas electricity will flow over the border and make an impact on the electricity price. In years with a high (low) level of precipitation and melting water electricity is flowing out (in) of the Nordic market in most hours of the year. The development of nuclear power-plants in Sweden and Finland, as well as the general expansion of energy production capacity, will impact the future electricity price.

Chapter III: Managing Risk in the Nordic Electricity Market

3.1 Why do firms manage their risk exposures?

Firms throughout the world spend time and resources on risk management. Risk management is about assessing the corporation's exposure to various sources of risk. These risks can be managed with the use of financial derivatives, insurance, and/or other activities. A firm's risk profile consists of the kind of risks that they are exposed to. This could for example be currency risk or interest rate risk. According to Hiller et al. (2008), the idea that corporations should manage their exposure to different sources of risk is becoming increasingly important. The increased focus on risk management can be due to a number of factors: increased volatility of interest rates and exchange rates, the increased importance of multinational corporations, and the development and availability of various derivative products.

In their ground breaking article "The Cost of Capital, Corporation Finance and Theory of Investment" Modigliani and Miller (1958) proposed what is know as the M&M theorem. The M&M theorem states that, under the perfect capital markets assumption, that the value of an equity financed firm and a leveraged firm are the same. Under this assumption there should be no need for corporations to hedge their risks. However, in the real world, there are some benefits of hedging.

The risks a firm is facing can be divided into market risk and firm-specific risk. Market risk is generally not diversifiable; however, it can often be hedged by taking offsetting positions in financial derivatives such as options, forward contracts, swap contracts, and futures (Hiller et al., 2008). One example of market risk could be the price of crude oil. When the price of crude oil was above USD100 per barrel, an oil producer who was dependent on an oil price of USD75 per barrel to realize a project, could use hedging instruments to insure himself against a fall in the oil price below USD75 per barrel. Firm-specific risk is generally diversifiable, but cannot be hedged with derivative contracts. However, it can be possible to hedge firm-specific risk with insurance contracts.

The value of a corporation has not increased if only the variability of the future cash flow is decreased. To improve a firm's value, hedging must also increase the expected cash flow. According to Hiller et al. (2008), a firm that is hurt more by a negative realisation of an economic variable, than it is helped by a positive realisation, can increase its value by hedging. The same authors list the main benefits of hedging to be:

1. Hedging can decrease a firm's expected tax payments due to different tax treatment of gains and losses.

2. Financial distress costs could be arising from conflicts between debt holders and equity holders, and reluctance among the customers and suppliers to do business with a firm that is experiencing financial difficulties. Therefore, by hedging their uncertainties, corporations can increase their value by reducing the probability of facing financial distress. Reducing financial distress could also increase the productivity of the employees because the probability of unemployment will decrease.

3. Hedging allow firms to better plan their future capital needs and reduce their need to gain access to outside capital markets. This is because the variability of the cash flows can be reduced and therefore make planning easier.

4. Hedging can be used to improve the design of management compensation contracts since the performance of the firm will be less dependent on market risk factors, therefore it can allow the firms to evaluate their top executives more accurately.

5. Hedging can improve the quality of the investment and operating decisions. This could be done by reducing the profit volatility of individual business units. Less volatility can provide the upper management with better information about where to allocate capital and which managers that deserve promotions.

In developing their risk management strategies, firms should consider each of the above reasons for hedging. They should focus their strategy around the factors which are the most important for their firm. Following Hiller et al. (2008), risk managers should concentrate about hedging risk in the best possible way, according to their mandate, and not gamble by taking speculative positions in the derivative markets.

3.2 Why should a power producer hedge the risk he is facing?

According to Bessembinder and Lemmon (2002) the extreme volatility of electricity prices implies that even well-capitalised power firms may have sufficiently large exposure to the price of electricity for a major price change to lead to a default of the firm or bankruptcy. According to the same authors two major California power retailers, Southern California Edison and Pacific Gas and Electric, defaulted on scheduled payments to creditors and suppliers during January 2001. The companies blamed the defaults on high costs of purchasing electricity in the wholesale markets. Also, due to the high capital intensity of building power plants, maintaining the energy production, and distribution of the electricity, there is a need for the investors to secure their investment by managing the risk in the best possible way. Following Bessembinder and Lemmon (2002) power producers have used bilateral forward contracts for decades to manage the risk they are facing. The liberalisation of the power markets and the development of the electricity exchanges have contributed to the "hedging-toolbox" of the electricity producers.

LaGattuta et al. (2000) find that the cash flow volatility of electricity producers in the United States have become significantly more volatile for the period 1996 – 1999 than earlier in the decade. This means that, if the risk managers were to base their risk management strategies on experience from the last decade he would be underestimating his risk exposure. With increasing volatility of electricity prices the need for more accurate and precise hedging vehicles increases in order to reduce the cost of financial distress. If market participants do not protect themselves against the increased cash flow volatility they may take riskier positions than necessary.

In order for an energy firm to maximise its value it is likely to pay attention to both expected profits and the volatility of profits. Higher expected profits will increase the firm value, while higher volatility can impose costs due to an increase in the likelihood of financial distress and make an impact on future investment decisions. The next section of the paper will look at different hedging theories. The section after that will analyse the factors separating electricity from other commodities and the implications these factors have on hedging.

3.3 Hedging theory

In the real world, when hedging with forward and futures, the hedger rarely manages to hedge away all the risk he is facing. This can be due to many reasons. Hull (2008) mentions three factors which could impact the quality of the hedge:

1. The asset whose price is to be hedged may not be exactly the same as the asset underlying the futures contract.
2. The hedger may be uncertain as to the exact date when the asset will be bought or sold.
3. The hedge may require the futures contract to be closed out before its delivery month.

These factors are also highly relevant for the market participants at Nord Pool and they should take them into consideration when assessing the quality of their hedge. If the market participant uses a forward contract as the only hedging vehicle he will not have hedged away all the risk. This is because he must buy or sell in his respective area price while the forward contract is denominated in the system price. Thereby, he is exposed to basis risk. Also, the timeframe of the hedging vehicles may not fully cover his needs in the spot market.

As noted by Ederington (1979), hedging theory consists of three main theories which take the above factors into consideration in different ways: **the traditional theory**, **the theories of Holbrook Working**, and **the portfolio theory**. The portfolio theory, which is applied most in practice, suggests a method for measuring the hedging effectiveness of a portfolio consisting of futures contracts and a commodity. The portfolio theory will be used to assess the hedging opportunities available to an electricity producer later in the paper.

There is also a discussion whether the corporations should spend their resources on hedging their risks or whether the investors can do this cheaper on their own by investing in a portfolio which resembles the market. However, the arguments proposed under 3.1 and 3.2 suggest that the owners of the electricity plants can benefit if the electricity producers are trying to reduce their risk by hedging.

3.3.1 Traditional hedging theory

According to Ederington (1979), traditional hedging theory emphasizes the potential of the futures market to hedge risk. Following the traditional theory the hedgers should take a futures market position equal to their initial position, but with opposite sign. For example, an oil producer with X barrels of oil could protect himself against a loss by selling X futures of the same commodity. If the spot and futures price at times t_1 and t_2 are S_1, S_2, F_1, and F_2, then the gain or loss on an unhedged position (U) of X units is $X[S_2 - S_1]$. The gain or a loss of a hedged position (H) is $X\{[S_2 - S_1] - [F_2 - F_1]\}$. Traditional theory argues that spot and futures prices generally move together so that the absolute value of H is less than U or that the variance of H is less than the variance of U, $Var(H) < Var(U)$. As noted earlier there are many factors which could have an impact on the quality of the hedge. Whether the spot and futures prices generally move together or not can be determined by investigating the basis.

3.3.2 The basis

There are two ways to define the basis. Hull (2008) defines the basis as the spot price of the asset to be hedged minus the futures price of the contract used. Ederington (1979), on the other hand, defines the basis as the difference between the futures and spot prices. The change in the basis between time t_1 and t_2 is $\{(F_2 - S_2) - (F_1 - S_1)\}$ or $-\{(S_2 - S_1) - (F_2 - F_1)\}$. If the change in the basis over time is zero the hedge is viewed as perfect. It is commonly argued that the basis and changes in the basis are small because of the possibility of making or taking delivery. The basis risk is the uncertainty associated with the basis. For most storable commodities the spot price and the futures price will converge towards maturity. However, this is different for non-storable commodities like electricity.

Castelino et al. (1991) regards the basis as an important measure of the cost of using forward and futures contracts to hedge. They also determine three dimensions to the basis risk for a hedge without full convergence of the price between the hedging vehicle and the underlying commodity (cross-hedge). The first is the level of predictability of the price spread between the commodity being hedged and the one underlying the futures contract. The second is the level of predictability of convergence between the prices of the futures contract and its underlying commodity. The third dimension is the time dimension, the timing of the hedge.

3.3.3 Working's Hypothesis

In Working's (1953) view, hedgers functioned very much like speculators. However, since they held positions in the cash market as well, they were concerned with relative and not absolute price changes. Working did not expect cash and futures prices to move together and he argued that most hedging is done in expectation of a change in spot-futures price relations. For example, holders of a long position in the cash market would hedge if the basis was expected to fall and would not hedge if the basis was expected to rise. The hedgers would in that case not act as pure risk minimisers but maximise expected profit.

3.3.4 Portfolio hedging theory

Johnson (1960) and Stein (1961) sought to further develop the traditional hedging theory and Workings theory. By viewing hedging as an application of basic portfolio theory they were able to integrate the risk avoidance of traditional theory with Working's hypothesis of expected profit maximisation. Johnson (1960) concludes in his article on page 150 that:

"There is no distinction between the hedger and the "ordinary" speculator insofar as both are motivated by a desire to obtain a for-them optimum combination of $E(R)$ *and* $V(R)$ *as determined by their respective utility functions."*

By adapting this holistic view Stein argues that corporations who hedge strive to maximise their expected return while minimising their variance based on their respective utility functions. Both Johnson and Stein argued that a market participant buys or sells futures for the same risk-return reasons that one buys any other security. Johnson (1960) empirically observed that traders could assume market positions that represented a mixture of hedging and speculative activity. By applying portfolio theory Johnson and Stein could explain why hedgers would hold both hedged and unhedged commodities.

According to Ederington (1979), one difference between the portfolio model of hedging and the financial portfolio model is that cash and futures market holdings are not viewed as substitutes. Instead, the spot market holdings, X_s, are viewed as fixed and the decision is how much of this position to hedge. To draw the parallel from a regular commodity to electricity, the spot market holding X_s is the expected electricity production during that period. To simplify the model according to Johnson and Stein I will focus on the case were the hedger holds only one spot market commodity or security.

Following Ederington (1979) the expected return and variance on an unhedged portfolio can be written as:

$$E(U) = X_s E[S_2 - S_1] \qquad (2)$$

$$Var(U) = X_s^2 \sigma_s^2 \qquad (3)$$

The expected return and variance on a hedged portfolio containing both X_s and X_f are given by:

$$E(R) = X_s E[S_2 - S_1] + X_f E[F_2 - F_1] - K(X_f) \qquad (4)$$

$$Var(R) = X_s^2 \sigma_s^2 + X_f^2 \sigma_f^2 + 2 X_s X_f \sigma_{sf}^2 \qquad (5)$$

Where, X_s and X_f represent the spot and futures market position.

$K(X_f)$ encompasses the brokerage fees and other costs from the futures transaction including the cost of providing margin. $\sigma_s^2, \sigma_f^2, \sigma_{sf}^2$ represent the variances and the covariance of the possible price changes from time 1 to time 2.

The hedged portfolio may be either fully hedged or partially hedged. According to Ederington (1979), traditional theory would assume that $X_f = -X_s$, this is not necessary in portfolio theory. In portfolio theory cash and futures holdings can even have the same sign. I let $b = {-X_f}/{X_s}$ represent the proportion of the spot position which is hedged. In a hedge X_s and X_f usually have opposite sign, so b is usually positive. By multiplying equation (3) with $\frac{X_s^2}{X_s^2}$ we get equation (5).

$$\mathrm{Var}(\mathrm{R}) = \left(\mathrm{X_s^2\sigma_s^2 + X_f^2\sigma_f^2 + 2X_sX_f\sigma_{sf}^2}\right) * \frac{\mathrm{X_s^2}}{\mathrm{X_s^2}}$$

$$\mathrm{Var}(\mathrm{R}) = \mathrm{X_s^2\sigma_s^2 + X_s^2}\left(\left(-\frac{\mathrm{X_f}}{\mathrm{X_s}}\right)^2\right)\sigma_f^2 + 2\left(-\mathrm{X_s^2}\left(-\frac{\mathrm{X_f}}{\mathrm{X_s}}\right)\sigma_{sf}^2\right)$$

$$\mathrm{Var}(\mathrm{R}) = \mathrm{X_s^2\sigma_s^2 + X_s^2}\left((\mathrm{b})^2\right)\sigma_f^2 + 2\left(-\mathrm{X_s^2}(\mathrm{b})\sigma_{sf}^2\right)$$

$$\mathrm{Var}(\mathrm{R}) = \mathrm{X_s^2\sigma_s^2 + X_s^2b^2\sigma_f^2 - 2X_s^2b\sigma_{sf}^2}$$

$$Var(R) = X_s^2 \left\{ \sigma_s^2 + b^2 \sigma_f^2 - 2b\sigma_{sf} \right\} \qquad (6)$$

$$E(R) = X_s E[S_2 - S_1] + X_f E[F_2 - F_1] - K(X_f)$$

$$E(R) = X_s \left\{ E(S_2 - S_1) - bE(F_2 - F_1) \right\} - K(X_s, b)$$

$$E(R)=X_s\{(1-b)E(S_2-S_1)-bE(S_2-S_1)-bE(F_2-F_1)\}-K(X_s,b) \quad (7)$$

Following Ederington (1979) we could also let $E(\Delta B)=E\{(F_2-S_2)-(F_1-S_1)\}$ be an expression for the expected change in the basis,

$$E(R)=X_s[(1-b)E(S)-bE(\Delta B)]-K(X_s,b) \quad (8)$$

where $E(S)=E(S_2-S_1)$ is the expected price change on one unit of spot commodity. If the expected change in the basis is zero, then the expected gain or loss is reduced as b goes towards 1. The expected changes in the basis could add to or subtract from the gain or loss which would have been expected on an unhedged portfolio.

In order to consider the effect of a change in b on the expected return and variance of the portfolio R I will hold X_s constant. By deriving equation (5) with respect to b we get:

$$\frac{\partial Var(R)}{\partial b}=X_s\{2b\sigma_f^2-2\sigma_{sf}\} \quad (9)$$

The risk minimising b (b^*) is found by setting equation (8) equal to zero and solving for b.

$$X_s\{2b\sigma_f^2-2\sigma_{sf}\}=0$$
$$X_s(2b\sigma_f^2)=X_s 2\sigma_{sf}$$
$$2b\sigma_f^2=2\sigma_{sf}$$

$$b^*=\frac{\sigma_{sf}}{\sigma_f^2} \quad (10)$$

3.3.5 How to measure the effectiveness of the hedge

The goal of this section is to provide a way to estimate the effectiveness of the forward contracts ability to reduce the risk that the power producers are facing. Portfolio theory provides a measure of hedging effectiveness according to Ederington (1979). The risk reduction of a hedge depends on the chosen b. The potential for the forward market to reduce the risk can be measured by comparing the risk of an unhedged portfolio with a hedged portfolio. As Ederingtion we will also use the percent reduction in the variance as a measure of the hedging effectiveness:

$$\mathrm{e}=1-\frac{\mathrm{Var(R^*)}}{\mathrm{Var(U)}} \quad (11)$$

where $\mathrm{Var(R^*)}$ represent the variance on a hedged portfolio, preferably from the minimum variance portfolio.

By substituting $b^* = \frac{\sigma_{sf}}{\sigma_f^2}$ into $Var(R) = X_s^2\left\{\sigma_s^2 + b^2\sigma_f^2 - 2b\sigma_{sf}\right\}$ we get

$$\mathrm{Var}(\mathrm{R}^*) = \mathrm{X}_s^2\left\{\sigma_s^2 + \left(\frac{\sigma_{sf}}{\sigma_f^2}\right)^2\sigma_f^2 - 2\left(\frac{\sigma_{sf}}{\sigma_f^2}\right)\sigma_{sf}\right\}$$

$$\mathrm{Var}(\mathrm{R}^*) = \mathrm{X}_s^2\left\{\sigma_s^2 + \frac{\sigma_{sf}^2}{\sigma_f^2} - 2\frac{\sigma_{sf}^2}{\sigma_f^2}\right\}$$

$$\mathrm{Var}(\mathrm{R}^*) = \mathrm{X}_s^2\left\{\sigma_s^2 - \frac{\sigma_{sf}^2}{\sigma_f^2}\right\}$$

Then we solve for e by using $Var(U) = X_s^2\sigma_s^2$ and $\mathrm{Var(R^*)}$:

$$e = 1 - \frac{\sigma_s^2 + \frac{\sigma_{sf}^2}{\sigma_f^2}}{\sigma_s^2}$$

$$e = 1 - \frac{\sigma_s^2 + \frac{\sigma_{sf}^2}{\sigma_f^2}}{\sigma_s^2}$$

$$e = 1 - \frac{\sigma_s^2}{\sigma_s^2} + \frac{\sigma_{sf}^2\sigma_f^{-2}}{\sigma_s^2}$$

$$e = 1 - 1 + \frac{\sigma_{sf}^2\sigma_f^{-2}}{\sigma_s^2}$$

$$e = \frac{\sigma_{sf}^2}{\sigma_s^2\sigma_f^2} = \rho^2 \tag{12}$$

3.3.6 How to determine the optimal Forward Position

Bessembinder and Lemmon (2002) determine the optimal forward position, when the objective function is linear in expected profit and the variance of profit is known, to be:

$$\mathrm{Q}_{\{P,R\}i}^{F} = \frac{\mathrm{P_F} - \mathrm{E}(\mathrm{P_W})}{\mathrm{A} * \mathrm{Var}(\mathrm{P_W})} + \frac{\mathrm{Cov}\left(\rho_{\{P,R\}i}, \mathrm{P_W}\right)}{\mathrm{Var}(\mathrm{P_W})} \tag{13}$$

As we see from equation (13) the optimal forward position contains two elements. The first term on the right side reflects the position taken in response to the bias in the forward price as compared to the expected spot price. The second term is the quantity of electricity sold forward to minimise the variance of the profits. Forward hedging can reduce the risk associated with our initial position because the covariance between the initial position and the forward contract is non-zero. I will not apply Bessembinder and Lemmon's optimal forward position equation (13) in this paper. However, in future research, their optimal forward position could be analysed through a case similar to the one in Chapter 5. In the case I apply the minimum variance portfolios which also take into account the covariance between the assets.

3.4 Hedging in the Electricity Market

3.4.1 What is special about the electricity market?

Electricity is a commodity with many characteristics that makes it different from other commodities, such as oil. In their paper, Marckhoff and Whimschulte (2009) points out some of the unique characteristics of electricity:

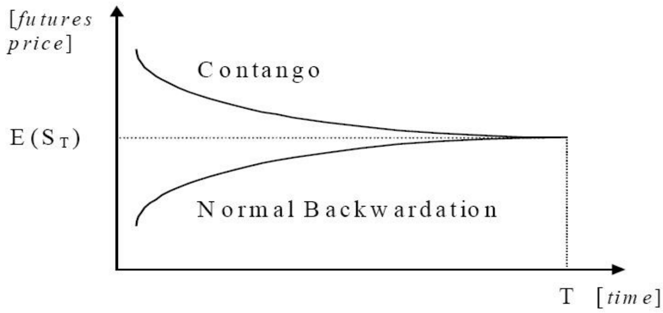
"The transportation and distribution of electricity require a special power grid. Power losses on the grid over large distances, fees for third-party access to the grid and especially congestion of transmission lines restrict regional electricity exchange and thus hamper the alignment of prices."

What sets electricity the most apart from other commodities is the fact that it cannot be economically stored. Botterud et al. (2002) says that it can be argued that electricity producers can "store" the commodity, for example in water reservoirs for hydro plants or as coal for thermal power plants. However, it is not possible to buy substantial amounts of electricity today and store it for future sales. According to Bessembinder and Lemmon (2002) the spot prices for electricity are volatile because inventories cannot be used to smooth supply and demand shocks. As a result, electricity prices experiences, in general, temporary upward spikes. Evidence of these spikes can be seen in the data from Nord Pool illustrated in Appendix A. The characteristics of electricity and the resulting volatility of spot prices impact the pricing of the available hedging vehicles.

3.4.2 Convergence of electricity forwards

According to Botterud et al. (2002) there are two main theories trying to explain the relationship between commodity spot and futures prices, and the convergence of future prices. The first theory is the theory of storage and the second theory tries to explain the futures price in terms of the expected future spot price and a corresponding risk premium. Futures prices for storable commodities like oil and gold, converges toward the spot price towards maturity as illustrated in Figure 3.1. If the futures price is higher (lower) than the spot price the futures price is said to be in contango (backwardation).

Figure 3.1 – Futures convergence



Source: Botterud et al. (2002) page 5.

The theory of storage tries to explain the difference between the spot price and futures price for a storable commodity as a result of warehousing costs, forgone interest in storing a commodity, and a convenience yield on the commodity. The theory of storage rests on the assumption of no-arbitrage. For a no-arbitrage condition to apply, a cost-of-carry relationship must link the spot and forward prices (Bessembinder and Lemmon, 2002). The arbitrage strategies required to enforce the cost of carry relationship consists of purchasing the asset at the spot price and storing it for sale at the forward price. The possibility of making arbitrage profits ensures the convergence, seen in graph 3.1, of futures and forward prices for commodities like oil and gold. This strategy cannot be executed with electricity as the underlying due to the nature of the commodity.

The second theory tries to explain the price of a futures contract in terms of the expected future spot price and a risk premium. The size of the risk premium depends on the discount rate applied by the market participants. According to Botterud et al. (2002) a risk premium could arise if either the number of participants on the supply side differs substantially from the number on the demand side, or if the degree of risk aversion varies considerably between the two sides. An overweight of risk-averse producers (purchasers) wanting to hedge their positions with futures contracts would probably result in futures prices being lower (higher) than the expected futures spot price. If a risk premia exist, the futures prices cannot be considered to be an unbiased predictor of future spot prices, Marckhoff and Wimschulte (2009). The same authors argue that:

"The understanding of risk premia, when pricing electricity futures, is therefore important for economic agents in the electricity market. Producers rely on price forecasts, for example for planning and budgeting purposes, while consumers use them to make their investment and consumption decisions. An assumption of unbiased futures prices would result in incorrect estimates of future spot prices and thus inefficient decisions of market participants."

Following Marckhoff and Wimschulte's argument it is crucial to determine whether there are risk premia present in the electricity forwards. The next section is devoted to risk premia in the electricity markets.

3.4.3 Analysing CfDs with a risk premium approach

The following discussion is based on Marckhoff and Wimschulte (2009). The fact that CfDs could be replicated with a position in an area and system forward allow us to apply existing electricity forward pricing models when analysing CfDs. As emphasised in the previous section, the theory of storage is not directly applicable to the electricity market. In the electricity market it is the expectations and risk preferences of market participants that determine the futures prices. Cootner (1960) and Dusak (1973) where among the first to introduce the theory that a futures price at time t with maturity in T ($F_{t,T}$) could be split into the **expected future spot price** ($E\left(S_T \mid \Omega_t\right)$) and a **risk premium** (π_t^F). The risk premia represents a premia (discount) that buyers (sellers) of futures contracts are willing to pay (accept) in addition to the expected future spot price in order to reduce the risk of unfavourable future spot price movements. According to this theory the futures price can be calculated as

$$F_{t,T} = E\left(S_T \mid \Omega_t\right) + \pi_t^F \qquad (14)$$

where Ω_t is the information set available at time t.

According to Lucia and Torró (2008) we distinguish between the **ex-ante premium** and the **ex-post premium**. The ex ante approach, given in equation (15), is to determine the future price consisting of the expected future spot price plus an expected risk premium. The premium in equation (15), $\pi_{t,T}^F$, is the ex ante or expected premium. The ex ante premia should be distinguished from the ex post premia.

$$F_{t,T} = E\left(S_T \mid \Omega_t\right) + \pi^F_{t,T} \qquad (15)$$

The ex post risk premia is defined as the difference between the futures price and the spot price at maturity:

$$\pi^F_t = F_{t,T} - S_T \qquad (16)$$

Lucia and Torró also show that the ex ante and ex post risk premium can be related to each other by definition:

$$F_{t,T} - S_T = \pi^F_{t,T} + E\left(S_T \mid \Omega_t\right) - S_T \qquad (17)$$

Equation (17) says that the ex post premium equals the ex ante premium plus the expected future spot price minus the future spot price.

In order to analyse whether there is ex post risk premia in the CfDs listed at Nord Pool from 2001 to 2008 I will use equation (18) which is based on equation (16).

$$\pi^{CfD}_t = \frac{\sum_{i=1}^{n} CfD_i}{n} - \frac{\sum_{i=1}^{N}\left(P^A_i - P^S_i\right)}{N} \qquad (18)$$

Where n is the number of traded days for the CfD contract and N is the number of delivery days for the CfD contract. I calculate the ex post risk premium (π^{CfD}_t) of a CfD at time t by:

1. Estimate the average, $\frac{\sum_{i=1}^{n} CfD_i}{n}$, of the prices for each CfD during the trading period.
2. Estimate the average of the spread between the area price, corresponding to the CfD, and the system price during the delivery period, $\frac{\sum_{i=1}^{N}\left(P^A_i - P^{SYS}_i\right)}{N}$. P^A_i and P^S_i is the daily average of the area and system price for each delivery day.
3. Then I take the average of the CfD price during the trading period minus the average of the spread between the area price, corresponding to the CfD, and the system price.

By following these three steps I analyse whether there are ex-post risk premia in the CfD prices.

3.4.4 Evidence of risk premia in futures and CfD prices

The existence of risk premia in electricity futures are addressed in several papers. Longstaff and Wang (2004) conducted an empirical analysis of forward prices in the Pennsylvania, New Jersey, and Maryland electricity market. With their dataset of hourly spot and day-ahead forward prices they found significant risk premia in the electricity forward prices. They also found that the risk premia vary systematically throughout the day and are directly related to economic risk factors, such as the volatility of unexpected changes in demand, spot prices, and total revenues. Hadsell (2006) find positive forward premiums in the electric market operated by the New York State Independent Systems Operator. He also find that the average premium levels across zones are inversely related to the levels of congestion in these zones. Lucia and Torró (2008) analyse week futures traded at Nord Pool between 1998 and 2007. They find that, on average, there are significant positive risk premia in short term electricity futures prices. However, the size and significance of the premia varies, it is greatest during winter and zero during summer. Botterud et al. (2002) investigates futures prices from Nord Pool between 1995 and 2001. They find that the futures price on average exceed the actual spot price at delivery, which results in a significant positive risk premia.

Kristiansen (2004a) and Kristiansen (2004b) investigate the existence of a risk premium in the CfDs listed at Nord Pool between 2001 and 2003. Kristiansen identifies differences between the average CfD prices and the ex-post delivery prices. This indicates risk premia in the CfDs. Marckhoff and Wimschulte (2009) investigate the pricing of the CfD contracts listed at Nord Pool between 2001 and 2006. They find that CfD prices contain significant risk premia. However, their sign and size differ substantially between areas and delivery periods, because areas are subject to transmission congestion to a varying extent.

Chapter IV: Empirical Analysis of basis risk at Nord Pool

4.1 Data

All the data used in working with this paper were retrieved directly from Nord Pool's database with the assistance of Agder Energi unless stated otherwise. My dataset consists of all system and area prices with the corresponding CfDs and forward contracts from the 1st of January 2000 to the 31st of December 2008. The minimum contract size is 1 MW. The contracts are denominated in NOK/MWh with two decimals until the end of 2005 and in EUR/MWh thereafter. If data were not available in both NOK and EUR, I converted the prices at official exchange rates given by Nord Pool. As a proxy for the daily system and area spot price I used the average of each days 24 hour day-ahead traded prices. For the financial products I used each day's closing price. In case of no transactions on a certain trading day, Nord Pool employs several procedures for estimating closing prices (Marckhoff and Wimschulte, 2009).

The first CfDs were introduced on November 17th 2000 with delivery in 2001. The first CfDs were season contracts with delivery in January-April (Winter 1), March-September (Summer), and October-December (Winter 2). Year contracts were introduced in 2002 and month contracts were introduced in 2004. Nord Pool switched from seasonal contracts to quarterly contracts in 2006 in order to conform to international standards. My data base consists of all CfD prices from November 17th, 2000 to December 31th, 2008 and the corresponding spot and system forward prices. In total, there are 35 year, 60 quarter, 74 season, and 241 month CfDs with delivery in that period. For each area, CfDs are tradable for the next two months, three quarter and three years. Trading is not possible during the delivery period. According to Marckhoff and Wimschulte (2009) active exchange trading only takes place in CfDs for the two Danish areas. However, Marckhoff and Wimschulte states that:

"Given that market makers quote binding bid and ask prices for all CfDs virtually every trading day from 13:00 until the end of trading at 15:30 and over-the-counter transactions in CfDs are regularly submitted to Nord Pool for clearing, closing prices for CfDs can be regarded as realistic market prices."

From 2001 to 2006 the CfD contracts for the DK1 and DK2 area accounted for 68% of the total traded volume. However, according to the same authors, the total over-the-counter traded volume for all areas was about twice as large as the traded volume at Nord Pool's financial market during the same period.

When working with the data I used Microsoft Excel 2007 and MatLab. My Table 4.2, 4.3, 4.4, and 4.5 are constructed much in the same way as done by Marckhoff and Wimschulte (2009) in their Table 1, 2, 4, and 5. Their Tables can be found on page 259, 260, 263, and 264 in their article, which I have listed in the bibliography.

4.2 Electricity production in the Nordic countries and its impact on prices

4.2.1 Different electricity sources and its impact on prices and transmission

The transfer of electricity from one area to another is driven by the supply and demand in each area. The supply of electricity in the Nordic areas is driven by the considerably different generation mix and the resulting cost structures among the Nordic electricity producers. The generation mix of the countries bordering to the Nordic countries does also have an impact on the transfer of electricity to and from the Nordic market. In Table 4.1 we see the rough generation mix of the Nord Pool countries and their net imports from 2004 to 2007.

Table 4.1 – Electricity generation Nordic countries

Total electricity generation by energy source and net exchange of electricity, TWh

	Denmark				Finland				Norway				Sweden			
	2007	2006	2005	2004	2007	2006	2005	2004	2007	2006	2005	2004	2007	2006	2005	2004
Total generation[3)]	37,2	43,2	34,4	38,4	77,8	78,6	67,9	82,1	137,4	121,7	138,0	110,5	145,1	140,3	154,7	148,8
Total thermal power	27,7	34,6	23,6	29,0	53,6	55,9	44,2	56,0	0,7	0,4	0,4	0,4	68,2	68,8	73,4	80,2
- Nuclear power	-	-			22,5	22,0	22,3	21,8	-	-			64,3	65,0	69,5	75,0
- Other thermal power [1)]	27,7	34,6	23,6	29,0	31,1	33,9	21,9	34,2	0,7	0,4	0,4	0,4	3,9	3,8	3,9	5,2
- Coal	20,3	25,8	14,5	17,8	13,6	16,1	7,0	15,8	-	-			0,9	1,0	1,1	1,5
- Oil	0,3	0,1	0,3	1,1	0,4	1,8	1,5	1,8	-	-			0,8	1,2	1,4	2,2
- Peat	0,0	0,0			7,0	6,2	4,5	6,5	-	-			0,1	0,1	0,1	0,1
- Natural gas	6,8	8,5	8,6	10,0	10,1	9,8	8,9	10,1	0,7	0,4	0,4	0,4	1,2	0,9	0,7	0,8
- Others [2)]	0,3	0,2	0,2	0,1	-	-			-	-			0,9	0,6	0,6	0,6
Total renewable power	9,6	8,6	10,8	9,4	24,2	22,7	23,7	26,1	136,7	121,3	137,6	110,1	76,9	71,5	81,3	68,6
- Hydro power	0,0	0,0	0,0	0,0	14,0	11,3	13,6	14,9	135,0	119,9	136,5	109,2	65,5	61,2	72,1	60,1
- Other renewable power	9,5	8,6	10,8	9,4	10,2	11,4	10,1	11,2	1,7	1,4	1,1	0,9	11,4	10,3	9,2	8,5
- Wind power	7,2	6,1	6,6	6,6	0,2	0,2	0,2	0,1	0,9	0,7	0,5	0,3	1,4	1,0	0,9	0,9
- Bio fuel	0,3	0,8	2,9	1,4	9,4	10,1	8,9	10,1	0,0	0,4	0,3	0,3	8,7	8,2	7,4	6,8
- Waste	1,6	1,7	1,3	1,4	0,6	1,1	1,0	1,0	0,8	0,3	0,3	0,3	1,3	1,1	0,9	0,8
Net imports	-1,0	-6,9	1,4	-2,9	12,9	11,5	17,1	5,0	-10,0	0,9	-12,0	11,5	1,3	6,1	-7,4	-2,0

1) Fossil fuels

2) DK West includes refinery gas

3) In Norway: Gross electricity production

Source: Nordel (2007) and (2005)

From Table 4.1 we see that Denmark relies mainly on coal- and gas-fired power plants, but also wind power contributes a substantial part to the energy mix. On average Denmark exported some electricity between 2004 and 2007. Finland, on the other hand, was in a net import situation during the same years with most of the electricity imported from Russia. The domestic electricity production came mainly from a mix of nuclear, coal, natural gas, hydro power, and bio fuel driven electricity plants. In Norway, the electricity production comes almost entirely from hydropower. Since the electricity production from hydro plants are dependent on the level of precipitation and melting water, the Norwegian electricity production will vary from season to season and from year to year depending on the inflow of water to the reservoirs. We can see from the Table that Norway generated less electricity in 2004 and 2006 compared to 2005 and 2007. In 2004 and 2006 we were also net importers of electricity. Sweden’s energy mix consists largely of hydropower and nuclear power. The volatile nature of wind power, the seasonality of hydropower, and the fact that nuclear plants often run at limited capacity during the summer; impacts the flow of electricity between areas over time. As a consequence, the area prices and the level of transmission congestion will vary across space and time. The frequency of transmission congestion will be analysed in section 4.3.1.

4.2.2 Hydropower and its impact on prices

From Table 4.1 we see that hydropower constitutes a major share of the electricity generation in the Nordic market. According to Marckhoff and Wimschulte (2009) hydropower generators determine their electricity supply based on the current hydro balance in relation to the normal situation. As a result, variations in the reservoir levels typically have an impact on the supply immediately. The water reservoirs are only refilled naturally via precipitation or melting water. Bühler and Müller-Merbach (2007) show that an increased (decreased) availability of hydropower leads to a right (left) shift in the supply curve and therefore generally to lower (higher) system prices. The effect of hydropower is more pronounced for the area price than for the system price in the case of congestion management. The influence of hydropower on the area prices depends on the transmission capacities.

Marckhoff and Wimschulte (2009) use the difference between the current water reservoirs levels, measured in percent of their capacity, and their historic median as a proxy for hydropower generation capacity to test for the relation between hydropower and area price spreads in the Nordic market. They find that there exist a significant relation between area price spreads and relative water reservoir level deviations for all areas except Trondheim. Because of transmission congestion a high availability of hydropower in Norway results in a negative area price spread for Oslo and a positive spread for the other areas. An example of such a situation will be given in the form of a case and a discussion of the price differences of the NO1 and system price during 2007 and 2008 in the next chapter.

4.3 Analysis of the basis risk and its impact on hedging

4.3.1 Frequency of differences

As discussed earlier in this paper, price variations across space and time is dependent on the supply and demand of electricity in the different price areas and the transmission capacity between these areas. If the transmission capacity of the power grid is too small to equalise the differences in prices between the areas we will have a deviation in one or more of the area prices compared to the system price. In order to analyse how often the area prices deviates from the system price I compared the area prices of DK1, DK2, NO1, NO2, FI, and SE to the system price for each calendar day from 2000 to 2008. For the Copenhagen area there was no data available from 2000. Table 4.2 shows the frequency of the differences between the daily area prices and the system price in percentage, of all calendar days.

Until the end of 2005 the Norwegian Krone (NOK) was the primary currency, since then the Euro (EUR) has played this part. All four Nordic currencies are accepted, but they are converted to the primary currency, at an official rate set by Nord Pool, for each day. In order to ensure consistency I converted all prices into Euro before I compared the area prices with the system price. The influence of the German Kontek area, which was introduced in October 2005, on the system price calculation is limited to the available transmission capacity. The two Danish areas, DK1 and DK2, were treated the same way until 2006 when they became fully included in the system price calculation.

Table 4.2 – Frequency of differences

How often the daily area prices and the system price differ in percentage of all calendar days.

Area	2000	2001	2002	2003	2004	2005	2006	2007	2008
Aarhus (DK1)	99,7	91,2	96,4	98,9	98,9	96,2	98,9	98,4	99,5
Copenhagen (DK2)	n/a	78,4	71,8	83,6	96,7	83,0	99,2	94,5	100,0
Oslo (NO1)	82,5	69,6	66,6	82,5	95,4	71,0	98,9	94,0	99,5
Trondheim (NO2)	85,8	72,9	71,2	81,9	96,2	74,0	98,1	93,7	99,7
Helsinki (FI)	82,8	70,4	67,1	84,7	97,5	74,0	97,8	94,0	99,5
Stockholm (SE)	82,5	70,1	66,6	82,7	95,1	72,1	97,8	93,2	99,7

This Table presents information regarding the frequency of the differences between the daily area prices and the system price as a percentage of all calendar days.

From Table 4.2 we see that the inclusion of the DK1 and DK2 area in the system price calculation increased the frequency of the differences compared to the previous years. For the DK1 area the price differs from the system price for almost all days, and for the other areas it differs above 70 percent of all calendar days. From 2006 to 2008 the area prices differed from the system price over 90 percent of the time. This trend is likely to continue if the transmission capacity remains constant. However, the TSOs are investing in new transmission capacities, over time this could equalise some of the prices variations across space (Nordel, 2007). Then again, the increase in transmission capacities is most likely to be countered by the increasing electricity consumption in the different areas, so that the relative transmission capacity remains the same. Furthermore, it might not be economically efficient for the community as a whole to try to equalise all the price variations. That would require substantial investment in new transmission capacity.

The findings in Table 4.2 should catch the attention of every market participant at Nord Pool. The frequency of the differences, especially after 2006, is astounding. However, if the area and system prices had been compared on an hourly basis, the frequency of the differences would have been somewhat lower. This is because during low consumption hours (as during most nights) the transmission capacities between the areas are usually large enough to equalize the supply and demand over the entire grid. Nevertheless, every risk manager should carefully consider the implications posed by Table 4.2. Also, it is necessary for the risk managers to assess the risk of how large the spreads are when the area prices deviates from the system price. The spreads between the area and system prices are analysed in the next section, and the results displayed in Table 4.3.

4.3.2 Descriptive statistics

In addition to looking at the frequency of the price differences it is important to look at their sign and magnitude. The size and sign of the spread could have a great impact on the electricity producers decision of whether to hedge the risk they are facing or not. It is also relevant for how the market participants hedge their risk exposure. Table 4.3 presents the descriptive statistics of the differences between the area prices and the system price in absolute terms and in percentage terms relative to the system price. As in Table 4.2 the spot prices used are denominated in Euros. In Table 4.3 A the mean absolute and percentage difference between the area prices and the system price are calculated for the years 2000 to 2008. The exception is the DK2 area where data is only available from 2001 to 2008. The descriptive statistics in Table 4.3 B are calculated on the aggregate data for all areas during the same time frame (2000-2008). The exception here is also DK1 where the time frame is 2001 to 2008.

Table 4.3 – Descriptive statistics of differences

Descriptive statistics for differences between daily prices and the system price. **All values under MA and A are in EUR**

A. Mean absolute (MA) and percentage differences (PD) between the area and system price.

Area	2000		2001		2002		2003		2004		2005		2006		2007		2008	
	MA	PD	MA	PD	MA	PD	MA	PD	MA	PD	MA	PD	MA	PD	MA	PD	MA	PD
DK1	3,66	0,29	0,59	0,03	-1,44	0,03	-3,01	-0,08	-0,12	0,00	7,90	0,27	-4,41	-0,09	4,47	0,16	11,70	0,26
DK2	n/a	n/a	0,40	0,02	1,67	0,02	0,11	0,00	-0,57	-0,02	4,47	0,15	-0,06	0,00	5,08	0,18	11,91	0,27
NO1	-0,69	-0,05	-0,07	0,00	-0,34	0,00	0,42	0,01	0,48	0,02	-0,21	-0,01	0,63	0,01	-2,19	-0,08	-5,57	-0,12
NO2	-0,24	-0,02	0,31	0,01	-0,11	0,01	-0,03	0,00	0,21	0,01	0,06	0,00	0,38	0,01	1,66	0,06	6,45	0,14
FI	2,13	0,17	-0,31	-0,01	0,36	-0,01	-1,39	-0,04	-1,24	-0,04	1,19	0,04	-0,03	0,00	2,08	0,07	6,29	0,14
SE	1,49	0,12	-0,29	-0,01	0,70	-0,01	-0,21	-0,01	-0,84	-0,03	0,43	0,01	-0,48	-0,01	2,33	0,08	6,39	0,14

B. Statistics for absolute (A) and percentage differences (PD) between the area and system price 2000-2008 (2001-2008 for DK2)

Area	Mean		Median		Minimum		Maximum		Std.dev		Skewness		Kurtosis	
	A	PD	A	PD	A	PD	A	PD	A	PD	A	PD	A	PD
DK1	2,15	0,12	0,25	0,01	-93,04	-0,91	129,69	4,38	10,95	0,35	1,04	2,92	22,58	18,98
DK2	3,49	0,11	0,14	0,00	-33,43	-0,57	200,57	5,71	10,01	0,31	5,18	5,08	74,12	57,98
NO1	-0,84	-0,03	0,00	0,00	-32,94	-0,83	11,90	0,71	3,27	0,12	-3,91	-3,58	22,73	17,71
NO2	0,96	0,03	0,01	0,00	-17,98	-0,48	39,18	1,37	3,36	0,13	3,52	3,84	18,88	25,95
FI	1,01	0,05	0,00	0,00	-32,87	-0,54	74,84	1,55	4,62	0,18	3,31	3,04	34,92	13,44
SE	1,06	0,04	0,01	0,00	-15,18	-0,54	74,84	1,55	3,91	0,15	4,39	3,56	47,36	19,08

In Table 4.3 A, we have the mean absolute differences[1] in the first column and the percentage differences between the area and the system price[2] in the second column, for each year. The first column under each year reveals that the annual mean differences vary both between and within areas in size and sign. As noted earlier in the paper there are many factors which could impact the regional supply and demand of electricity through time. Changes in water reservoir levels for hydropower or weather conditions are two important factors. The mean differences are rather small for most areas most of the time; however, there are some significant exceptions. In the DK1 area both the mean absolute and percentage differences are more pronounced than in the other areas. In 2000, 2005, and 2008 the percentage difference for DK1 was 29%, 27%, and 26%, which is a remarkable difference. For the DK2 and FI area there are some larger differences compared to the NO1, NO2, and SE area. From 2006 to 2007 and 2007 to 2008 there was a large increase in the daily differences between the area

[1] (Area price – System price)
[2] ((Area price – System price)/System price)

and the system price. Especially in 2008 there were large differences, ranging from 12% to 26%, compared to the system price for all areas. The increase in the differences from 2006 to 2008 is most likely due the fact that the Danish areas were also included in the system price from 2006. However, in 2006 the mean and percentage differences were not that large.

The large spreads that we saw for all areas compared to the system price during 2008 could partially be due to two events that occurred in the South of Norway during 2008. First, according to a newsarticle in Teknisk Ukeblad (2008), during early spring there was a disruption in two electricity cables which are important for the transmission of electricity from South-Norway to Sweden. The first cable was repaired by the 25th of October and the second cable could transfer electricity at 50 percent rate from the 1st of November 2008. Second, the disruptions occurred during a period with much precipitation, melting water, and with a high level of water in the reservoirs. The hydro plants had to produce substantial amounts of electricity of which not as much as wanted was transferred to other areas. This lead to significantly lower prices in the NO1 area compared to the other areas and the system price between late March and August 2008 (Appendix A). The electricity producers in the South of Norway lost substantial amounts in forgone income due to these events. On the other hand, the electricity consumers in the NO1 area could purchase electricity at low prices. Events like these can lead to extreme price variations and underlines the need for appropriate hedging vehicles. The case in the next chapter will focus on what happened in the NO1 area during 2008 and the consequences it could have for electricity producers.

Part B of Table 4.3 follow the same setup as part A with the absolute and percentage differences in the first and second column under each column header. The difference is that here I have estimated the mean, median, minimum, maximum, standard deviation, skewness and kurtosis from the aggregated data for the areas DK1, NO1, NO2, FI and SE in the period 2000 to 2008. The DK2 area data is aggregated for the years 2001 to 2008.

From Table 4.3 B we can see some general trends in the dataset, for example, that the mean price for the NO1 area is lower than the system price while the other areas have a higher price during the time period. The extreme events that occurred in the NO1 area during 2008 made an impact on the aggregated data. The two Danish areas have a mean and a median that are larger than the other areas. The data indicates that local supply and demand shocks occur frequently. This is reflected in the extreme values of the price differences in Table 4.3 B. The maximum and minimum values that have occurred during the time period indicate substantial variations in the 'area minus system price' relationship.

If the data were normally distributed (mesokurtic) the moment coefficient of the kurtosis would be 3. We see from Table 4.3 B that all the values for the kurtosis are much larger than 3, this is a sign of a leptokurtic distribution. Compared with a mesokurtic distribution a leptokurtic distribution has a much higher peak around the mean and fatter tails. A leptokurtic distribution places more probability on the occurrences of extreme values than a mesokurtic distribution. If the distribution of the returns were symmetrical around the mean, the coefficient of skewness would be zero. The NO1 area is negatively skewed which means that the mean and median is found to the left of the mode in the distribution. This means that most of the supply-demand shocks result in a negative spread between the area and system price. The NO1 area is the only area where the absolute minimum is larger than the maximum spread between the area and system price. The aggregated prices for the other areas are positively skewed so here the mean and median is found to the right of the mode. Most of the shocks in these areas results in a positive spread between the area and system price.

Figure 4.1 – Area prices minus system price 2001 to 2008

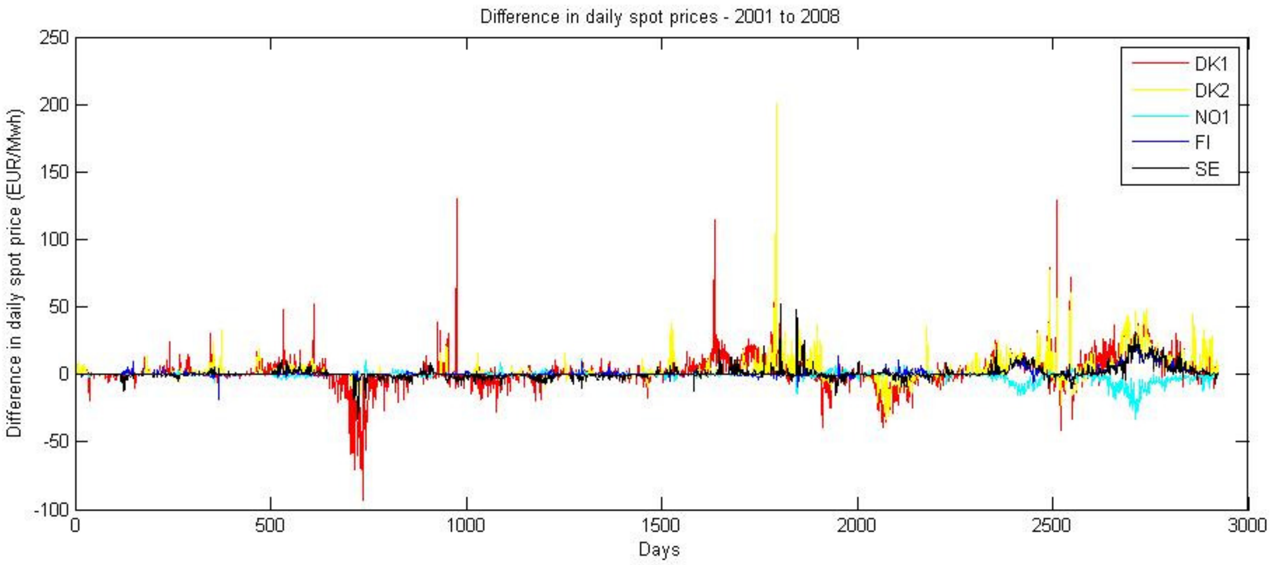


Figure 4.1 illustrates the daily spread between the DK1, DK2, NO1, FI, and SE area; and the system price from 2001 to 2008. On the left axis we have the daily difference in EUR/MWh and on the right axis we have the number of days. The graph shows clearly the supply and demand shocks that occurred during these years and the resulting basis risk present in the Nordic electricity market. Especially the Danish areas experience large variations over time. Also, we see the large spreads between the NO1 and the system price in 2008. However, the NO1 price didn't vary much from the system price before 2007 and 2008.

So by hedging with a forward hedge the electricity producers in the NO1 area most likely would have had an accepTable risk profile. But, if they went into 2008 with the same risk management strategy as in previous years, they would not have been as successful in reducing their risks. This is further illustrated with a case in the next chapter.

Based on the above analysis illustrated with Figure 4.1, Table 4.2, and Table 4.3 the need to manage the risk of locational price differences in the Nordic market should be of great concern to the risk managers employed by the electricity producers. In order to protect themselves against the risk of locational price spreads the electricity producers can hedge with CfDs. The use of CfDs makes it possible to create a perfect hedge. However, it is reasonable to expect that an electricity producer should have to pay a risk premium associated with hedging his risk. The next part of this analysis will discuss the pricing of CfDs and whether there is a risk premium in the CfD contracts.

4.3.3 Average traded prices CfD

In order to analyse the pricing of CfDs I constructed Table 4.4 which presents the average traded prices of the CfDs by delivery period. Depending on the year of maturity I aggregated the daily CfD prices for each area with the same delivery period. Then I calculated the mean and standard deviation of the aggregated CfD prices. The prices are given in NOK from 2001 to 2005 and in EUR from 2006 to 2008. We see from the Table below that the CfD prices are mainly positive and that there are large differences between the areas in terms of average price and standard deviation. Oslo (NO1) is the area that experiences negative CfD prices the most, with a little less than half of the prices. The other areas have almost entirely positive prices. The CfD of an area will trade at positive prices if the market expects the specific area price to be higher than the system price. That area would then be in a net import situation. For example, we see from Table 4.1 that Denmark was a net importer in 2005. The CfD prices for both the Danish areas were notably higher than for the other areas that year. If we look at the daily traded spot prices for 2005 we see that the DK1 and DK2 area prices were higher and varied more than the system price. We see from Table 4.3 that the DK1 area price varied the most from 2000 to 2008, this also reflected in the higher average traded prices for the DK1 area.

Table 4.4 – Average traded price CfDs

Average traded prices of Contracts for Difference by delivery period.

			VALUES IN NOK										VALUES IN EUR					
Contract	Delivery*	Listed**	2001		2002		2003		2004		2005		2006		2007		2008	
			Mean	STD	Mean	STD	Mean	STD	Mean	STD	Mean	STD	Mean	STD	Mean	STD	Mean	STD
DK1	Month	2	-	-	-	-	-	-	-	-	-	-	-	-	4,77	1,98	13,85	3,15
(SYARH)	Quarter	3	-	-	-	-	-	-	-	-	-	-	4,70	3,69	2,43	3,17	6,23	3,21
	Season	2	9,64	6,86	7,05	3,19	-12,61	23,95	1,06	7,43	31,18	9,55	-	-	-	-	-	-
	Year	1 (3)***	-	-	4,11	2,34	3,00	16,72	-3,16	4,05	19,63	4,89	5,40	1,52	3,87	3,33	4,54	0,52
DK2	Month	2	-	-	-	-	-	-	3,38	1,28	28,77	6,51	4,37	1,78	5,07	1,13	13,57	2,39
(SYCPH)	Quarter	3	-	-	-	-	-	-	-	-	-	-	6,77	3,08	4,43	2,26	7,33	2,17
	Season	2	2,51	1,46	12,61	3,95	6,53	4,83	8,07	2,70	20,35	7,36	-	-	-	-	-	-
	Year	1 (3)***	-	-	6,28	3,57	11,16	3,73	7,97	3,00	11,45	0,68	5,15	1,85	6,25	3,89	5,20	0,91
NO1	Month	2	-	-	-	-	-	-	2,58	0,33	-1,55	0,81	0,67	0,23	-0,86	0,63	-4,42	1,26
(SYOSL)	Quarter	3	-	-	-	-	-	-	-	-	-	-	0,14	0,39	0,11	0,68	-1,02	0,96
	Season	2	-2,40	1,05	-0,95	0,76	2,23	2,42	2,18	0,70	-0,14	1,60	-	-	-	-	-	-
	Year	1 (3)***	-	-	-0,33	0,48	-0,47	1,71	1,90	0,61	1,99	0,56	-0,13	0,11	0,43	0,36	-0,26	0,51
FI	Month	2	-	-	-	-	-	-	-3,42	1,04	8,09	2,04	0,66	0,37	1,46	0,57	5,75	1,07
(SYHEL)	Quarter	3	-	-	-	-	-	-	-	-	-	-	1,01	0,50	0,76	0,40	1,74	1,01
	Season	2	6,37	2,41	4,47	1,35	2,91	2,80	0,47	2,93	4,37	2,79	-	-	-	-	-	-
	Year	1 (3)***	-	-	3,53	1,12	5,33	0,65	2,50	1,12	1,91	1,76	1,03	0,37	0,73	0,28	0,89	0,29
SE	Month	2	-	-	-	-	-	-	0,22	1,46	6,21	1,37	0,61	0,31	1,05	0,59	5,48	1,15
(SYSTO)	Quarter	3	-	-	-	-	-	-	-	-	-	-	0,73	0,34	0,49	0,32	1,32	1,03
	Season	2	4,52	2,04	3,20	1,31	3,32	1,24	3,33	1,43	4,53	1,54	-	-	-	-	-	-
	Year	1 (3)***	-	-	2,22	1,26	3,93	0,52	3,80	0,97	2,94	0,67	0,74	0,17	0,44	0,21	0,46	0,14

*Delivery period of the contracts

**Number of contracts listed at the same time

*** 1 contract listed from 2002 to 2006 and 3 contracts listed from 2006

As stated earlier, positive CfD prices indicate that the market expects the different area prices to be higher than the system price on average. However, all of the area prices cannot be larger than the system price since it is the area prices that make up the system price. Therefore, the data in Table 4.4 indicates that the market participants at Nord Pool use CfDs to protect themselves against upward price spikes. It is the electricity purchasers who have the most to gain from a hedge against upward price spikes. The theory about futures prices and the data indicates that there is a significant risk premium in the CfD prices. In the next section I will analyse the existence of risk premia in the CfDs listed at Nord Pool.

4.3.4 Risk premia in CfD prices

As noted earlier in this paper, supply and demand across areas varies in sensitivity to weather conditions, therefore I expect the risk premia to differ in size and sign on a seasonal and geographical basis (Bühler and Müller-Merbach, 2007). I examine all CfDs with delivery between 2001 and 2008 to analyse whether there are risk premia in the prices. In order to test for risk premia I follow the method used by Marckhoff and Wimschulte (2009) and I calculate the risk premium according to equation (18). The mean of the ex-post CfD risk premia for each delivery period are given in Table 4.5. Season contracts are not aggregated because of the different delivery periods. The mean and standard deviation are given in NOK/MWh from 2001 to 2005 and in EUR/MWh from 2006 to 2008.

Table 4.5 – Ex-post risk premia CfD

Ex-post risk premia of CfDs listed at Nord Pool between 2001 and 2008.

		VALUES IN NOK					VALUES IN EUR		
Contract	Delivery Period	2001	2002	2003	2004	2005	2006	2007	2008
DK1	Month	-	-	-	-	-	-	0,30	2,15
(SYARH)	Quarter	-	-	-	-	-	9,11	-2,04	-5,47
	Winter 1	19,94	-10,16	46,57	-8,97	-3,67	-	-	-
	Summer	6,04	-10,12	-19,50	10,54	-41,37	-	-	-
	Winter 2	-11,03	104,44	14,54	9,30	-43,24	-	-	-
	Year	-	14,39	25,28	-2,10	-42,79	9,81	-0,60	-7,25
DK2	Month	-	-	-	8,08	-6,76	4,43	-0,01	1,66
(SYCPH)	Quarter	-	-	-	-	-	6,83	-0,65	-4,58
	Winter 1	-	-10,55	14,30	11,18	-17,51	-	-	-
	Summer	6,26	-3,44	-1,29	16,32	17,55	-	-	-
	Winter 2	-9,74	20,43	5,80	11,31	-65,65	-	-	-
	Year	-	-6,37	10,11	12,67	-24,08	5,21	1,17	-6,71
NO1	Month	-	-	-	-1,44	0,13	0,04	1,33	1,15
(SYOSL)	Quarter	-	-	-	-	-	-0,49	2,30	4,55
	Winter 1	-4,40	0,39	-6,81	-1,95	5,11	-	-	-
	Summer	-2,23	5,24	4,27	-2,86	0,23	-	-	-
	Winter 2	1,68	-2,92	-2,17	-0,13	-0,81	-	-	-
	Year	-	2,21	-3,79	-2,12	3,67	-0,76	2,62	5,31
FI	Month	-	-	-	6,96	-1,39	0,69	-0,62	-0,72
(SYHEL)	Quarter	-	-	-	-	-	1,04	-1,32	-4,55
	Winter 1	11,21	1,85	17,61	13,03	-4,43	-	-	-
	Summer	13,69	-9,62	8,79	12,54	-1,85	-	-	-
	Winter 2	-0,78	20,71	18,11	6,44	-10,50	-	-	-
	Year	-	0,74	16,39	12,88	-7,57	1,06	-1,35	-5,40
SE	Month	-	-	-	7,20	2,77	1,09	-1,28	-0,91
(SYSTO)	Quarter	-	-	-	-	-	1,21	-1,84	-5,07
	Winter 1	9,01	1,19	11,56	10,67	-1,58	-	-	-
	Summer	10,73	-9,32	-1,96	10,31	2,93	-	-	-
	Winter 2	-1,71	5,72	7,33	10,19	1,48	-	-	-
	Year	-	-3,02	5,44	10,78	-0,50	1,22	-1,89	-5,93

Table 4.5 strongly indicates that the CfD prices contain a risk premia. The risk premia differs in sign and size across the areas and delivery periods. The NO1 CfD risk premia have, in most cases, the opposite sign of the other areas. The reason for that could be the high share of hydro power in Norway and the limited transmission capacities to other areas that sometimes results in a lower area price for the Oslo area compared to the system price. In periods with a high level of precipitation and snow melting, Norway is a large exporter of cheap electricity, which results in the NO1 price being lower than the system price. This leads to an increased hedging demand from electricity producers in Norway order to protect themselves against this spread (Marckhoff and Wimschulte, 2009). The electricity produced in the other Nordic countries comes mainly from thermal units (Table 4.1). Finland, Denmark, and to some extent Sweden, will be net importers of electricity in wet periods. These factors result in a positive spread between the area price and system price for the other Nordic areas. The positive risk premia for most of the CfDs are attributed to the overweight of risk-averse consumers being willing to pay a risk premium to receive the future price spread (Marckhoff and Wimschulte, 2009). Karakstani and Bunn (2008) finds that different technical plant characteristics in the UK lead to changing hedging needs and thus a risk premia that varies with time. They also find that the CfD risk premia varies across delivery periods, but that there is no significant relation between the risk premia and the length of the respective delivery period.

From Table 4.5 we see that the DK1 and DK2 CfD prices contain a higher risk premia than the CfDs for the other areas. This is most likely related to the higher volatility of the Danish area prices and therefore a corresponding higher risk premia. We can also see from Table 4.5 that the risk premia of Summer contracts usually differs from the risk premia of Winter 1 and Winter 2 contracts. However, the size and sign of the risk premia differs greatly across areas and time.

In this chapter I have analysed the spread between the area prices and system price at Nord Pool. My analysis shows a significant amount of basis risk in the Nordic electricity market. I have also analysed a hedging vehicle, Contracts for Difference, which may be used to hedge away the basis risk. CfDs provide the market participants with the opportunity to create a perfect hedge. In the next chapter I will analyse through a case how an electricity producer can hedge against the basis risk present in the Nordic market and demonstrate how CfDs can be used.

Chapter V: Case study – Real Power AS

5.1 Case overview

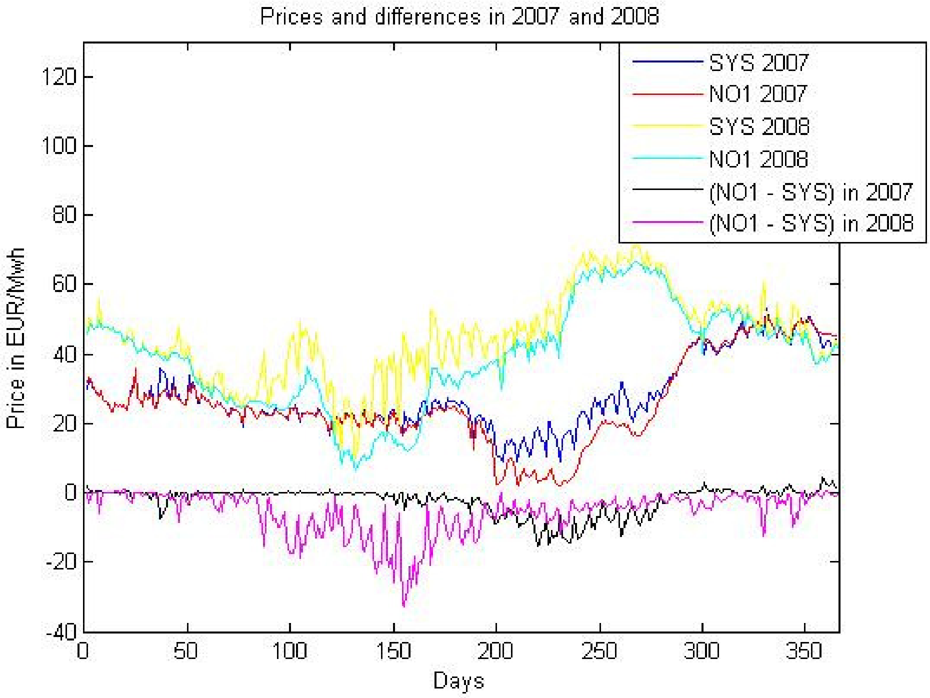
In order to illustrate the effect that price variations, in the area- and system-price, can have on an electricity producer I have constructed a case. The company, Real Power AS (also called 'Real Power' or 'the company') is a fictional electricity producer located in the South of Norway (NO1 area). Real Power owns and operates a run-of-the-river hydro power plant. The flow rate of the river will always be so strong that the turbines will run at maximum capacity. The river is not regulated in any way upstream. I assume that the company will produce at maximum capacity at any point in time with no disruptions. The maximum capacity for Real Power is 50 MW.

The case illustrates five hedging/no hedging Alternatives available to Real Power during two specific points in time with certain assumptions. The first period will be 2007, and 2008 the second period. All the prices in the case are denominated in EUR. I will describe the data being used before I go into details regarding the hedging Alternatives.

5.2 Description of the data

As noted earlier, the relevant time periods for the case are 2007 and 2008. Since Real Power is located in the Oslo area the relevant time series data for the case are the data for the NO1 area and the system price during 2007 and 2008. These time series are illustrated in Figure 5.1 below. 'SYS 2007' and 'SYS 2008' shows the system prices for 2007 and 2008. 'NO1 2007' and 'NO1 2008' are the NO1 area price during 2007 and 2008. '(NO1 – SYS) in 2007' and '(NO1 – SYS) in 2008' are the NO1 area price minus the system price for the respective years. We see from the graph that the spread between the NO1 and the system price in 2007 was relatively sTable most of the year; however, in the beginning of the second half of the year it varied some. In 2007 the average spread and standard deviation was -2.2 EUR/MWh and 3.93 EUR/MWh. In 2008 the average spread and standard deviation was -5.57 EUR/MWh and 6.2 EUR/MWh. As the figure and the numbers explain, the market volatility was clearly higher in 2008 than in 2007.

Figure 5.1 – Overview market prices 2007 and 2008



The time series for the NO1 area price and system price in 2007 goes from the 1st of January to the 31st of December 2007 with a total of 365 days. The forward contract with delivery during the same period, ENOYR-07, was first listed on January 2nd 2004 with a cost of 26.5 EUR/MWh. The year CfD contract with delivery during the same time period, SYOSLYR-07, was first listed on January 2nd 2006 with a price of -0.3 EUR/MWh. A negative CfD price indicates that the market expects the area price to be lower than the system price. The time series for the NO1 area price and system price in 2008 goes from the 1st of January to the 31st of December 2008 with a total of 366 days. The forward contract with delivery during the same period, ENOYR-08, was first listed on January the 3rd 2005 with a cost of 27.15 EUR/MWh. The year CfD contract with delivery during the same time period, SYOSLYR-08, was first listed on December 13th 2006 with a price of 0.4 EUR/MWh. A positive CfD price indicates that the market expects the area price to be higher than the system price.

Table 5.1 – Overview financial prices used

Contract	Date	Price
ENOYR-07	02.01.2004	26.5 EUR/MWh
ENOYR-08	03.01.2005	27.15 EUR/MWh
SYOSLYR-07	02.01.2006	-0.3 EUR/MWh
SYOSLYR-08	13.12.2006	0.4 EUR/MWh

I assume here that all the forward contracts and CfDs, which Real Power enters into, are shorted on their first day of listing at Nord Pool. The dates and prices for the contracts used in this case are noted in the above paragraph. There is no settlement before the delivery period for the forward and CfD contracts. During the delivery period the contracts are settled financially everyday.

5.3 Hedging Alternatives

In this section I will go through five different hedging/no hedging Alternatives available to Real Power. The equations of the cash-flows from each of the Alternatives are given below in Table 5.2.

Table 5.2 – Cash-flow of the five Alternatives

The cash-flow per MWh for the five Alternatives.

	Cash-flow
Alternative 1	$\mathrm{P}_t^{\mathrm{NO1}}$
Alternative 2	$P_t^{NO1} + \left(F_t^S - P_t^S\right) * 0.5$
Alternative 3	$\mathrm{P}_t^{\mathrm{NO1}} + \left(\mathrm{F}_t^{\mathrm{S}} - \mathrm{P}_t^{\mathrm{S}}\right)$
Alternative 4	$P_t^{NO1} * X_s + \left(F_t^S - P_t^S\right) * X_f$
Alternative 5	$\mathrm{P}_t^{\mathrm{NO1}} + \left(\mathrm{F}_t^{\mathrm{S}} - \mathrm{P}_t^{\mathrm{S}}\right) + \left(\mathrm{P}_t^{\mathrm{S}} - \mathrm{P}_t^{\mathrm{NO1}}\right) + \mathrm{C}^{\mathrm{CfD}}$

Notation: $\mathrm{P}_t^{\mathrm{NO1}}$ = spot price NO1 $\mathrm{F}_t^{\mathrm{S}}$ = forward price $\mathrm{P}_t^{\mathrm{S}}$ = system price

$\mathrm{C}^{\mathrm{CfD}}$ = price of CfD contract X_s = position in spot market X_f = position in forward market

5.3.1 Alternative 1

In the first Alternative I assume that Real Power sells the electricity it produces in the spot market. The cash-flow will be completely dependent on the day-to-day NO1 area price, $\mathrm{P}_t^{\mathrm{NO1}}$. Alternative 1's income will be highly volatile in this case. If the company has obligations, for example in terms of debt that it raised to build the hydro plant, being dependent on a certain area price to meet these obligations would substantially increase the risk of default. A low NO1 price over time will lead to financial uncertainty for the company. This would again lead to a higher bankruptcy risk for the company. However, Real Power can decrease the risk of only being dependent on the area price by hedging in the forward market. The next four Alternatives represent different ways to hedge in the forward market.

5.3.2 Alternative 2

The hedging strategy in Alternative 2 requires that Real Power goes short in the forward market 50 percent of its exposure in the spot market. The cash-flow is given by equation $P_t^{NO1} + \left(F_t^S - P_t^S\right) * 0.5$. Explained in a more straightforward way, with Alternative 2, the company has to short one forward contract worth 1 MWh for every 2 MWh it sells in the spot market. By shorting the forwards, Real Power is guaranteed to receive the amount the shorted forward contract is valued at per MWh. This will reduce the variability of the cash-flow. However, the forward position is exposed to changes in the basis during the delivery period due to variations between the NO1 and system price. Alternative 2 provides Real Power with flexibility in terms of varying its exposure if the assumptions were to be relaxed. If, for example, the company would not produce at maximum capacity at all times due to varying flow rate of the river, a 50 percent forward hedge could be more appropriate than a full forward hedge. Also, if the analysts and risk managers at Real Power expects the NO1 price to be higher than the system price in the future, they would probably hedge less of its exposure to the area spot market. This relates to the portfolio hedging theory proposed by Stein (1961) which argues that corporations who hedge strives to maximise their expected return while minimising their variance based on their respective utility functions. Johnson (1960) empirically observed that traders could assume market positions that represented a mixture of hedging and speculative activity. In line with Jonson's observations it is not unlikely that an electricity producer in the NO1 area would hedge a smaller amount of his exposure in the area spot market if they thought that the area price would be higher than the system price in the future. By doing this they could reap the benefits of a higher NO1 price.

5.3.3 Alternative 3

According to Ederington (1979), a 'traditional hedger' should take a futures market position equal to his initial position, but with opposite sign. With Alternative 3, I will analyse the effects of a traditional hedge (full hedge) during 2007 and 2008 and compare it to the other hedging Alternatives. The cash-flow from Alternative 3 is given by $\mathrm{P}_\mathrm{t}^{\mathrm{NO1}} + \left(\mathrm{F}_\mathrm{t}^\mathrm{S} - \mathrm{P}_\mathrm{t}^\mathrm{S}\right)$. For every 1 MWh sold at the NO1 area price the company will short 1 MWh worth of forward contract. These steps would ensure that Real Power is guaranteed to receive the amount the shorted forward contract is valued at per MWh. This could reduce the variability of the income stream; however, the company would still be exposed to basis risk. With a short forward hedge Real Power will sell its electricity production in the spot market at the NO1 area price while the shorted forward contract will be settled in cash. If a situation occurred where the system price became so much larger than the NO1 area price, so that the difference would be higher than the price of the forward contract, Real Power would actually loose money on a daily basis. Traditional theory argues that spot and futures prices generally move together, as seen in figure 5.1 this does not have to be the case. The changes in the basis can be very large at Nord Pool. Due to the characteristics of electricity, the futures price does not have to converge towards the spot price at delivery. Castelino et al. (1991) regards the basis as an important measure of the cost of using forwards to hedge. In order to improve the hedging theory, new theories were developed by Working (1953), Johnson (1960), and Stein (1961). In Alternative 4 I will apply the minimum variance portfolio approach which is often associated with the portfolio hedging theory.

5.3.4 Alternative 4

Following Ederington (1979), in portfolio hedging theory, the position in the spot market is viewed as fixed. The decision is how much of this position to hedge. In portfolio theory there are no restrictions on the sign of the hedging position or the size of it. The cash-flow in Alternative 4 is determined by $P_t^{NO1} * X_s + \left(F_t^S - P_t^S\right) * X_f$. The spot market position is fixed to be 1. There are two ways to estimate the risk minimising allocation in the forward market, which both yield the same results. The first way is to estimate the minimum variance portfolio by minimising the variance in equation (4). Thereby, finding the risk minimising allocation in the forward position. The second way is to apply equation (9) to find the risk minimising b^* and then use the equation $b = {}^{-X_f}\!/_{X_s}$ to find the allocation in X_f. I regard the area price as asset 1 and $\left(F_t^S - P_t^S\right)$ as the second asset. To find the variance of the second asset and the covariance between the two assets I used the historic data from 2007 and 2008. The calculations to find the risk minimising allocation in X_f are summarised on the next page.

2007	2008
$b^* = \frac{\sigma_{sf}}{\sigma_f^2}$	$b^* = \frac{\sigma_{sf}}{\sigma_f^2}$
$b^* = \frac{-119.901}{101.98} = -1.1757$	$b^* = \frac{-165.58}{154.82} = -1.0695$
$b = -\frac{X_f}{X_s}$	$b = -\frac{X_f}{X_s}$
$-1.1757 = -\frac{X_f}{1}$	$-1.0695 = -\frac{X_f}{1}$
$X_f = \underline{\underline{1.1757}}$	$X_f = \underline{\underline{1.0695}}$

To find the cash-flow in Alternative 4 I plug the risk minimising X_f values into the equation given in Table 5.1: $P_t^{NO1} * X_s + \left(F_t^S - P_t^S\right) * X_f$. According to the minimum variance approach Real Power should have larger positions in the short forward market than it has in the spot market. This will result in a lower variance for Alternative 4 than for Alternative 3. However, then the company would be even more exposed to changes in the basis compared to a traditional hedge, following the argument in the previous section concerning Alternative 3. The minimum variance portfolio cannot completely hedge the possibility of financial distress, due to the variability of the area and system price. In order to be completely protected against basis risk Real Power must combine a short forward hedge with a CfD hedge. This will be done in Alternative 5.

5.3.5 Alternative 5

In the fifth Alternative Real Power will follow the three-step process outlined in section 2.5.3 to create a perfect hedge using CfDs. By following the three-step process Real Power will be completely protected against basis risk. In order to do it correctly the company would have to short one CfD contract for every forward contract that they have shorted. By applying this hedging strategy Real Power can lock in their future cash flow with zero variation. However, the company needs a counterparty to enter into the contract with. Due to the low liquidity of NO1 CfDs at Nord Pool it could be difficult to find a counterparty to enter into the CfD with. Depending on the market expectations regarding the NO1 – system price spread, the price of the CfD contract will vary.

5.4 Analysing the cash-flows

5.4.1 Real Power's cash-flow per MWh

In this section I calculate and analyse the cash-flow Real Power receives, on an hourly basis in 2007 and 2008, from the five hedging/no hedging Alternatives described in 5.2.

In Table 5.3 I have summarized the average and standard deviation of the five Alternatives based on the historic data from 2007 and 2008. Also, I have calculated e as a measure of the hedging effectiveness according to equation (11) (Ederington, 1979). e illustrates the potential of the forward market to reduce the risk by comparing the risk of an unhedged portfolio with a hedged portfolio. I have used Alternative 1 as the unhedged portfolio and the other Alternatives as hedged portfolios. In Table 5.3, e measures the percentage reduction in the variance of Alternative x compared to Alternative 1. However, an electricity producer in the real world would not focus blindly on variance reduction. Most likely, the utility function of an electricity producer does not require him to minimise the variance at all cost. He would also be concerned about the income he forgoes by minimising the risk of his portfolio. Therefore, I have calculated the variable Ipc according to equation (19).

$$\mathrm{Ipc} = \left(1 - \frac{\mathrm{Avg}\left(\mathrm{R}^{*}\right)}{\mathrm{Avg}\left(\mathrm{U}\right)}\right) * 100 \tag{19}$$

Where $\mathrm{Avg}\left(\mathrm{R}^{*}\right)$ is the average EUR/MWh cash-flow of the hedged portfolios, and $\mathrm{Avg}\left(\mathrm{U}\right)$ is the average EUR/MWh cash-flow of the unhedged portfolio. Ipc measures the percentage change in the cash-flow of Alternative x compared to the cash-flow of Alternative 1.

Table 5.3 – Cash-flow in EUR/MWh

Cash-flow in EUR/MWh for the five Alternatives.

	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5
2007*					
Average	25,73	25,02	24,31	24,06	26,80
St. Dev.	12,41	7,69	3,93	3,49	0
e[1)]	0	62%	90%	92%	100%
Ipc[2)]	0	-3%	-6%	-7%	4%
2008**					
Average	39,15	30,36	21,58	20,36	27,55
St. Dev.	14,68	9,40	6,19	6,13	0
e[1)]	0	59%	82%	83%	100%
Ipc[2)]	0	-22%	-45%	-48%	-30%

*N=365 [1)] = percentage reduction in the variance compared to Alternative 1
**N=366 [2)]= percentage change in the cash-flow compared to Alternative 1

We see from Table 5.3 that Real Power would receive the second highest average price per MWh if Alternative 1 was chosen in 2007. However, the standard deviation for this Alternative is much higher compared to the other Alternatives. Because of relatively low spread between the NO1 price and the system price during 2007 and a forward price cost of 26.5 EUR/MWh; the Alternatives 2, 3, and 4 yielded close to the same average EUR/MWh as Alternative 1. However, Alternative 2, 3, and 4 reduced the variance considerably compared to Alternative 1. The traditional hedge and minimum variance portfolio hedge reduced the variance with 90 and 92 percent. At the same time they only reduced the cash-flow by 6 and 7 percent compared to Alternative 1. In 2008, however, the reduction in the variance came at a higher cost.

The volatility in the Nordic electricity market was much higher than in 2008 compared to 2007. There were, at times, large variations between the NO1 price and the system price. Therefore, the variation in the average and standard deviation are much larger. The negative percentage change in the cash-flows of Alternative 2-5 compared to Alternative 1 is largely a result of the forward price of 27.15 EUR/MWh. In 2008, the NO1 area price actually provided the highest average price despite the low prices we saw during summer. When Real Power shorted the forward contract, ENOYR-08, on the 3rd of January 2005 the market did not expect the system price to be as high as it became on average in 2008. Both the standard deviation and average price per MWh are the highest for Alternative 1. Alternative 3 and 4 lowers the variance with 82 and 83 percent compared to Alternative 1. However, they also reduce the cash-flow with 45 and 48 percent. Alternative 2 reduces the variance with 59 percent while reducing the cash-flow with 22 percent. Alternative 5, represents a perfect hedge and has therefore a steady cash-flow per MWh with zero standard deviation. However, Alternative 5 reduces the cash-flow with 30 percent compared to Alternative 1. In addition to analyse the information in Table 5.3 it is informative to look at how the cash-flows of the Alternatives varied through the year. Figure 5.2 and 5.3 illustrates the actual day-to-day cash-flow Real Power would have received per MWh if the company had chosen any of the five Alternatives.

Figure 5.2 – Cash-flow of the five Alternatives in EUR/MWh - 2007

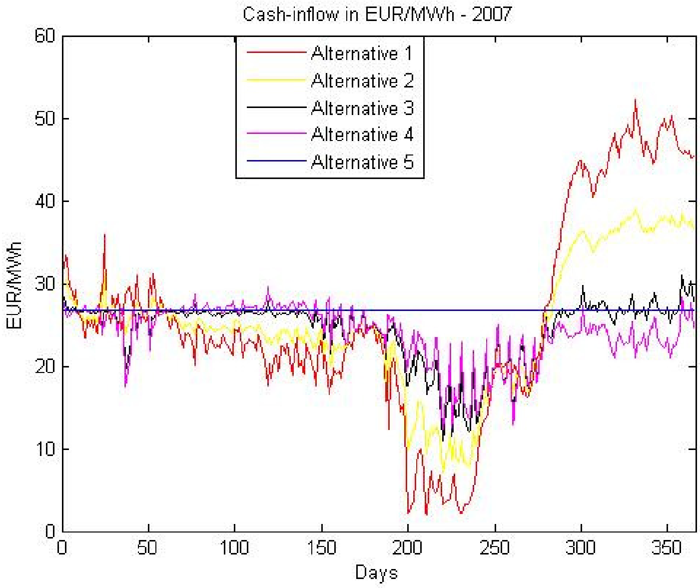


Figure 5.3 – Cash-flow of the five Alternatives in EUR/MWh - 2008

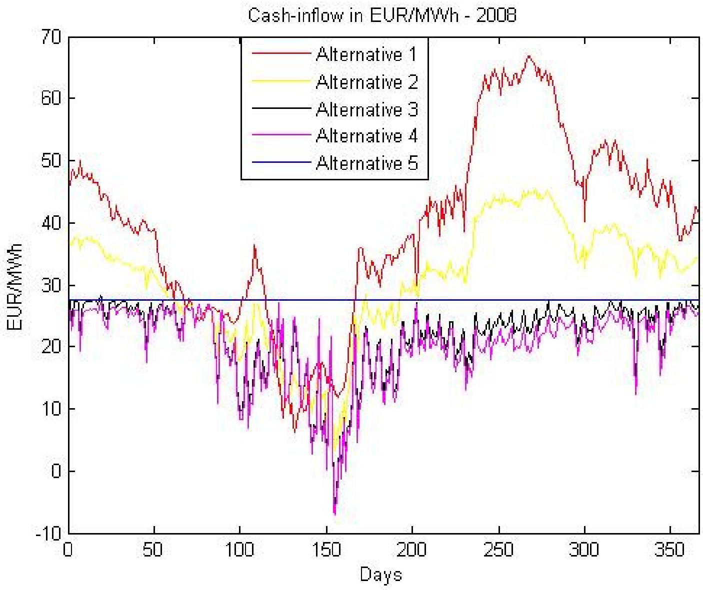


Figure 5.2 and 5.3 illustrate vary clearly the large variations in Real Power's cash-flow with the five Alternatives. It is important to note that the traditional full hedge and minimum variance hedge actually provided a negative cash-flow during a few days in 2008. Depending on Real Powers financial situation, the days with negative cash-flow would create financial distress costs. In addition to look at the cash-flow in EUR/MWh for the five Alternatives I will also analyse the total cash-flow from the five Alternatives.

5.4.2 Total cash-flow for Real Power

As noted in the overview of the case Real Power has a maximum capacity of 50 MW. The company will always produce at this rate 24 hours a day. In order to calculate the total cash inflow I multiply the hourly cash-flow per day for the five Alternatives with 50 MWh to find the total cash-flow per hour, then I multiply with 24 hours to get the daily cash-flow. The total cash-flow average and standard deviation are summarized in Table 5.4. In order to find the total income for the entire year I multiply the average income per day with the number of days for each year. The total income is given in the Sum. Also, I have added the change in the total income compared with Alternative 1 for the other Alternatives.

Table 5.4 – Total cash-flow

Cash-flow in EUR per day of the five Alternatives.

	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5
2007*					
Average[1)]	30 882	30 026	29 171	28 870	32 160
St. Dev.	14 888	9 232	4 715	4 186	0
Sum[2)]	11 271 828	10 959 576	10 647 324	10 537 572	11 738 400
Change[3)]	0	-312 252	-624 504	-734 256	466 572
2008**					
Average[1)]	46 983	36 437	25 892	24 426	33 060
St. Dev.	17 619	11 273	7 429	7 350	0
Sum[2)]	17 195 688	13 336 074	9 476 460	8 939 926	12 099 960
Change[3)]	0	-3 859 614	-7 719 228	-8 255 762	-5 095 728

1) The average per day is calculated by taking the daily average * 24 * 50
2) The Sum in 2007 (2008) is calculated by taking the average*N (n)
3) Change in the total cash –flow compared to Alternative 1
*N=365 (number of days)
**n=366 (number of days)

The most interesting aspect with Table 5.4 is to observe how the variations impact the total income. In 2007, the chosen hedging strategy (of the five Alternatives) would not have had that large impact on the total income. However, by only being dependent on the area price Real Power would have a standard deviation of 14 888 EUR per day. If Real Power is risk averse, the company should hedge away some of the risk it is facing. The most extreme variations are seen during 2008. Here, selling at the area spot price with no hedging would have provided substantially more to the bottom line of the company than the other Alternatives. The total changes varies from -3 859 614 EUR with Alternative 2 to -8 255 762 EUR with Alternative 4. In 2008, Real Power’s forgone income by choosing either Alternative 2, 3, 4, or 5 is evident. In order to see variations in the cash flow on a daily basis during 2007 and 2008 we only need to multiply the left axis in figure 5.2 and 5.3 with 1200 (50 MW * 24 hours). In the next section I will analyse the results of the five hedging/no hedging Alternatives with respect to the hedging theory introduced in Chapter 3.

5.5 Discussion of the results

According to Bessembinder and Lemmon (2002) the extreme volatility of electricity prices implies that even well-capitalised power firms could have sufficiently large exposures to the price of electricity for a major price change to lead to a default of the firm or bankruptcy. Real Power experienced extreme volatility during 2008 and fairly high volatility during 2007. If the company had high debt obligations, for example due to building the run-of-river plant, the company could face difficulties if the electricity price remained low over longer periods of time. Over the last nine years the spread between the NO1 price and the system price has varied, with 2007 and 2008 being the years with the largest spreads. In 2008, Alternative 1, 2, 3, and 4 had a very low cash-flow for several days during summer. The cash-flow was even negative for a few days with Alternative 3 and 4. If that situation had lasted for a longer period of time Real Power could have experienced severe financial problems. The inclusion of the two Danish areas in the system price calculations suggests that the volatility will continue to be high in the Nordic electricity market. LaGattuta, D, A. et al. (2000) finds that the cash flow volatility of electricity producers in the United States became significantly more volatile after the electricity market was deregulated. We have seen that this has also happened in the Nordic electricity market.

Following Hiller et al. (2008) the value of a corporation has not increased if only the variability of the future cash flow is decreased. To improve a firm's value, hedging must also increase the expected cash flows. We see from Table 5.3 that Alternative 2, 3, 4, and 5 decreases the variability of Real Power's cash flow in 2007 and 2008. However, Alternative 2, 3, and 4 did not increase the cash flows in either of the years. Alternative 5, on the other hand, increased the cash-flow in 2007 compared to Alternative 1, but not in 2008. Whether Real Power believes that it can increase its expected cash flow depends on the models and parameters it uses. How much the company values risk reduction depends on the electricity producer's risk aversion and utility-function. It is likely to assume that any electricity producer has obligations towards its debt holders and obligations towards its owners in terms of expected dividend payments. These factors imply that an electricity producer would try to lock in a certain profit each year. If the threshold the company/board of directors has set is reached, the company could adjust its risk profile (upward) in order to try to achieve a larger profit.

A firm that is hurt more by a negative realisation of an economic variable, than it is helped by a positive realisation, can increase its value by hedging (Hiller et al., 2008). I would argue that Real Power is more vulnerable to a negative realisation than it is to a positive economic realisation. The company would have experienced severe negative realisations during 2008 had it used Alternative 3 and 4. Luckily, this extreme situation did not last for that long. However, its impact on Real Power could have been dramatic. The situation had become more dramatic if the negative cash-flows had lasted for a longer time period than it did, or the area price had remained low the rest of the year. Problems repairing the transmission cables connecting the South of Norway with the rest of the Nordic electricity grid would definitively have impacted the area price. The low prices experienced during 2007 for the area price and during 2007 and 2008 for Alternative 1, 2, 3, and 4 could create financial distress costs at Real Power. These financial distress costs can materialise as conflicts between debt holders and equity holders, and/or uncertainties among the employees and customers. Financial distress can reduce the productivity of the employees, for example, due to the increased probability of unemployment.

5.5.1 Factors that can impact the quality of the hedge

Hull (2008) mention three factors which could impact the quality of the hedge in Alternative 2, 3, and 4. These can impact the hedge to a varying degree. The first factor to be considered is that the asset whose price is to be hedged may not be exactly the same as the underlying the futures contract. In Alternative 2, 3, and 4 this is the case. The hedge is done by shorting a forward contract whose underlying is the system price. The area price and the system price do not have to converge as we get closer to the delivery period due to the characteristics of electricity as a commodity. In Alternative 5 Real Power can use CfDs to offset the spread between the NO1 area price and the system price. The second factor to consider is that the hedger may be uncertain regarding the exact date when the asset will be bought or sold. In this case I have assumed that the company has a constant production and no other obligations with respect to deliver electricity. In the real world, the electricity producers have varying electricity production and delivery obligations. The third factor is that the hedge may require the futures contracts to be closed out before its delivery month. This factor has no impact on Real Power due to the assumptions I have made. However, this is an important challenge in the real world.

5.6 Summary and limitations

This case has illustrated the volatility and the risks that are present in the Nordic electricity market. The five hedging/no hedging strategies illustrate how the different Alternatives can hedge the risks present in the Nordic electricity market. The discussion regarding the existing hedging theory and why a corporation should hedge suggests that Real Power should hedge some of its future production. A traditional portfolio (Alternative 3) and a minimum variance portfolio (Alternative 4) managed to reduce the variability of Real Power's cash-flow. However, the case illustrated that there are other risk factors than the variability of the cash-flow that should be taken into consideration. These factors are illustrated with 'a worst case scenario', where the company experiences negative cash-flows. Alternative 1, on the other hand, left the company entirely exposed to the area price. This Alternative had the highest volatility in the cash-flow during both 2007 and 2008. Alternatives 2 and 5 appeared to yield the best risk adjusted cash-flow during both years. A mix of the two strategies would leave Real Power with flexibility to meet a varying electricity demand while at the same time allowing it to hedge its obligations to equity and debt holders. With a mix of the two strategies Real Power would also have the flexibility to adjust its own electricity production. I argue that a mix of these two strategies yield the best result regarding the 'hedging requirements' proposed by the existing hedging theory. The case has also illustrated the importance and flexibility of CfDs to hedge the basis risk present in the Nordic electricity market. However, the incorporation of CfDs in an electricity producers hedging strategy is limited by the low liquidity of the CfD market.

Chapter VI: Conclusion

The occurrence of grid congestion in the Nordic electricity market and the resulting spreads between the area prices and the system price is an important risk faced by the market participants at Nord Pool. The frequency of the difference between the area prices and system price has been above 90 percent over the last 3 years for all areas. My research indicates that locational price spreads will continue to appear frequently in the future as well. Also, the size and sign of the spread varies significantly over time. It can prove to be imperative for the market participants to hedge against the basis risk.

Contracts for Difference (CfD) is a financial product Nord Pool introduced in year 2000 I order to allow the market participants to manage the locational price spreads. I analyse the average traded CfD prices over the time period 2001 to 2008. The two Danish areas have on average the highest CfD prices, while the NO1 area sometimes has negative CfD prices. This relationship is heavily dependent on high share of hydro plants in the South of Norway. Further, I analyse the CfD prices for risk premia. The risk premia is calculated as the difference between the average CfD prices during the listing period minus the ex-post delivery price. The ex-post delivery price is calculated as the area price minus the system price during the delivery period of the CfD. I find evidence suggesting a risk premia in the CfD prices. However, the risk premia varies substantially across areas and time. Because of the existence of risk premia, CfD prices cannot be considered to an unbiased predictor of future price spreads.

Lastly, I constructed a case to illustrate how a fictional electricity producer located in the NO1 area could reduce the variability of his cash flows. I did that by analysing five Alternative ways to organise the company's risk management strategy during 2007 and 2008. The case illustrated how effective CfDs can be to minimise the risk an electricity producer is facing and thereby eliminate the cost associated with this risk. I also found that a full hedge and the minimum variance portfolio hedge performed poorly when looking at other factors than minimising the variance. I argue that an electricity producer should use a mix of forwards and CfDs in order to hedge the risk he is facing. The electricity producer should also hedge less than 100 percent of his exposure in the spot market, but more than 0 percent. By doing that the producer has more flexibility to adapt his risk profile if the dynamic of the electricity market should change.

Future research could expand the analysis of CfDs and investigate to what extent the electricity producers in the various areas actually use CfDs to hedge their risks. Also, the case study could be further developed to illustrate the risks the different market participants at Nord Pool are facing.

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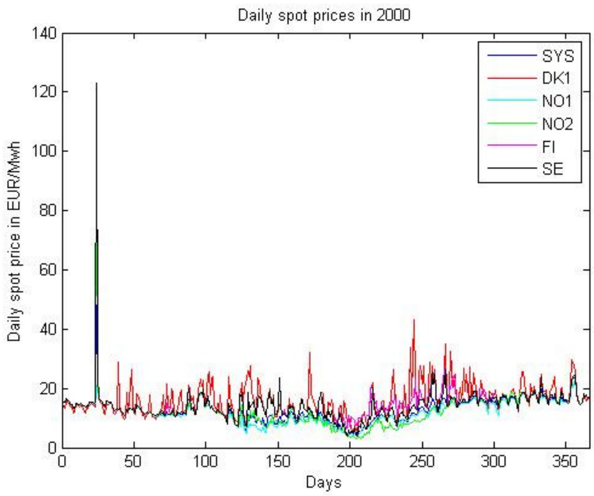
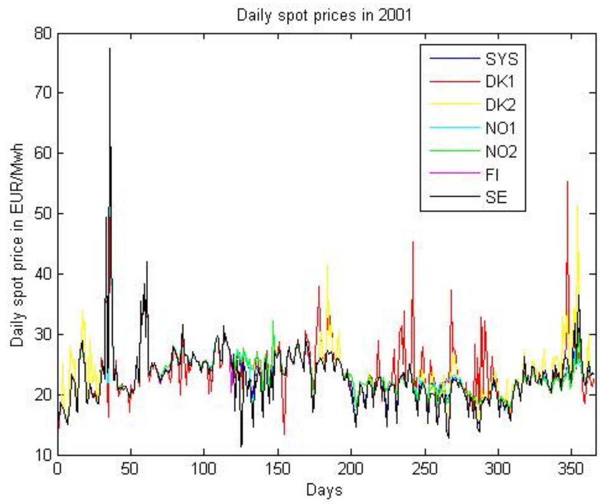
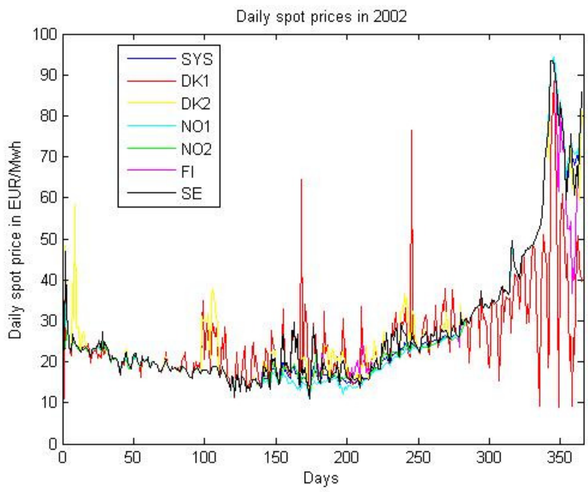
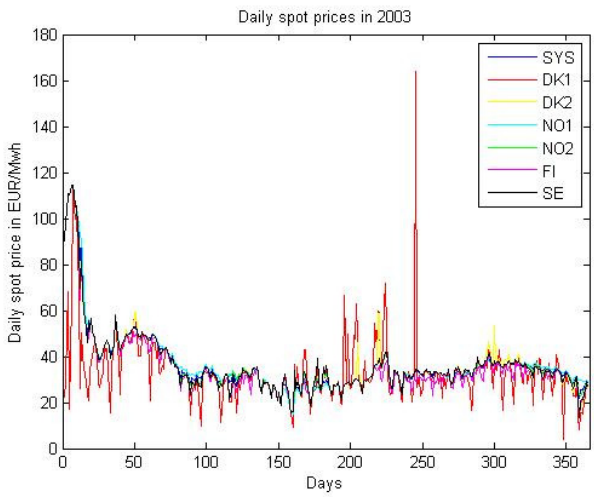
Appendix A

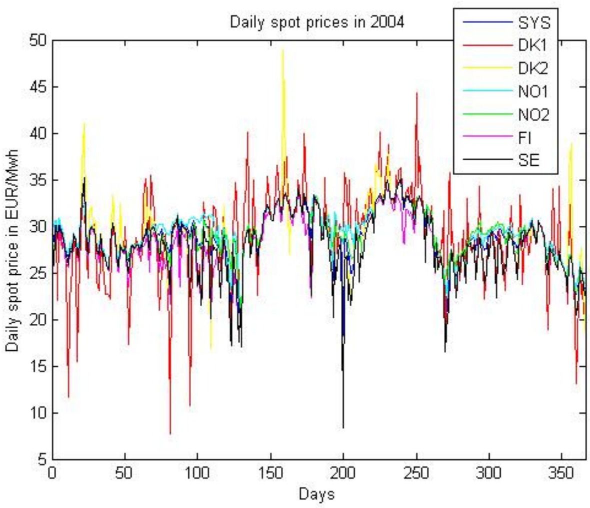
Overview prices 2000-2008.

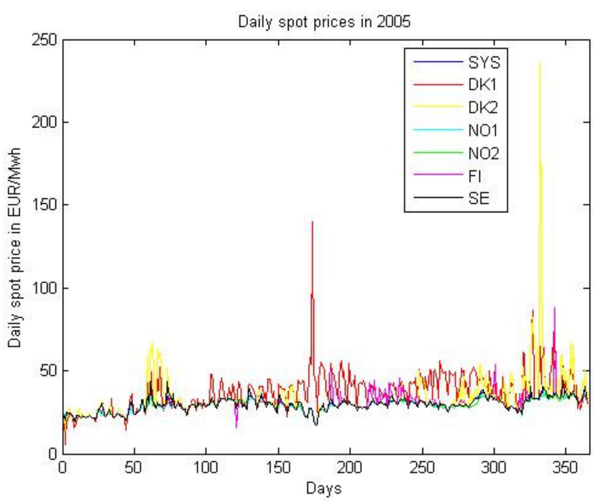


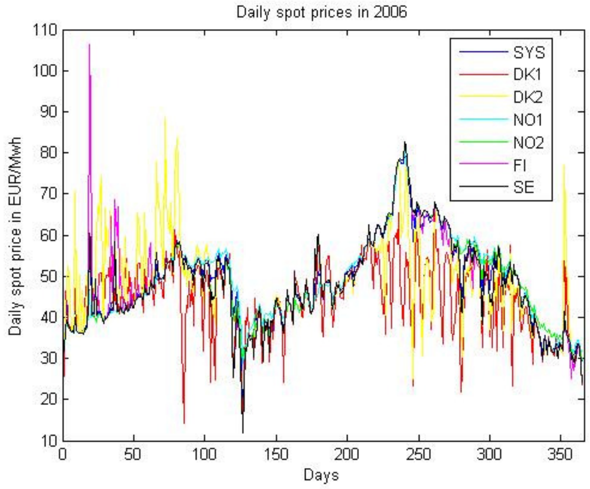








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Days
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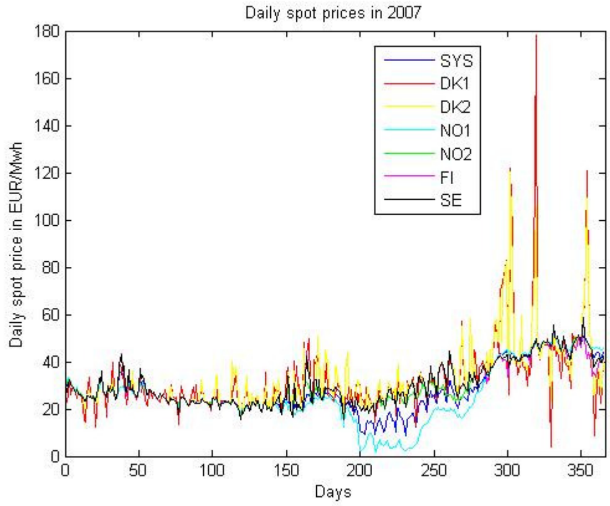
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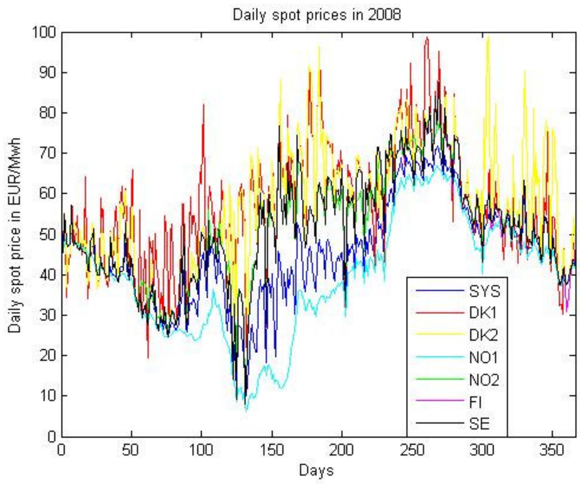
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