Pricing of Contracts for Difference in the Nordic Market

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Abstract

The purpose of this paper is to give an introduction to, and a pricing analysis of a new forward locational price differential product, Contracts for Difference (CfD), introduced the 17th of November 2000 at Nord Pool – the Nordic electricity exchange. To our knowledge there is no literature available of how the Nordic CfDs are priced. The CfD is a forward market product with reference to the difference between the future seasonal Area Price and System Price. By using available historical trading prices and spot prices for four seasonal contracts and one yearly contract, we analyse the relationships between the contract prices and the value of the underlying asset. For the first four seasonal contracts it appears that CfDs traded at Nord Pool are mostly over-priced relative to the underlying asset. Pricing theory for forward contracts explains this by the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential. We utilize statistical analysis with regard to the contract prices and the underlying asset, and find some interesting relationships. The analysis is preliminary due to the fact that the CfD market is relatively new.

Keywords: *Contracts for Difference; Transmission risk management; Contract prices*

1. Introduction

In many electricity markets there is now a demand for new risk management tools. The Nordic market has shown a growing concern for transmission congestion and the associated risks of Area/System Price differentials. As a result, Contracts for Differences (CfDs) were introduced at Nord Pool the 17th of November 2000. These financial instruments make it possible for the players in the market to hedge against the difference between the Area Price and the System Price in a future time period. The forward and futures contracts provided by Nord Pool are referred to the System Price, while the producers are being paid the Area Price in their area for their production, and the consumers purchase load at the Area Price referring to their area. Often the producers and consumers are located in different areas, facing periods with transmission congestion and Area Prices differing from the System Price. They may therefore be exposed to significant financial risks.

One extension of CfDs is transmission congestion contracts (TCCs) (Hogan, 1992). The TCC concept has been developed by Professor William W. Hogan at Harvard University (Hogan, 2002). TCCs can be used to hedge directly against a locational price difference, and they have been used in the PJM Interconnection (Pennsylvania, New Jersey and Maryland) since April 1998, and in New York since 1999. A study of how well the markets for hedging transmission congestion function is important because it will have implications for implementation in other regions. We study CfDs in one of the world's most advanced and liberalized electricity markets.

This paper describes the Nordic electricity market, Nordic transmission pricing, and congestion management procedures. We discuss general theory for pricing of forward contracts, and the principles of CfDs. Utilizing data from 17th November 2000 to 30th April 2002, we analyse the CfD prices with regard to the value of the underlying asset and volatility. Since the market for CfDs is relatively new, the limited data available might be insufficient to draw fully conclusive results.

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2. The Nordic power market

Since January 1996 Norway and Sweden have had a common electricity market, with Finland joining in September 1998, followed by western Denmark in January 1999 and eastern Denmark in October 2000. These now constitute one common Nordic market.

In the Nordic region Nord Pool organises two different markets for electricity, ***Elspot*** and ***Eltermin***. In the Elspot market buyers and sellers trade in a daily spot market concluded at the day-ahead stage. Traders can submit offers to sell or bids to buy the physical electricity they expect to produce or consume for every hour of the next day. The System Price (spot price) is determined by the intersection point of the aggregated purchase (demand) and sale (supply) curves. The System Price is the price independent of any transmission constraints (i.e. the unconstrained price), and is the spot price for the common Nordic[1] market.

The Eltermin market is a purely financial and is divided into: the ***futures*** and ***forwards*** markets. These are markets for cash settlement of a specified volume of power at an agreed upon price, date and period. The market participants may trade for delivery up to four years in advance. Futures and forwards are used for trading and risk management. The main difference between the futures and forwards is the daily marking to market and settlement of futures. Forwards are settled when the contracts reach their due dates. Forward contracts, which are the relevant contracts in this case, have 3 seasonal delivery periods: Winter 1 (weeks 1-16), Summer (weeks 17-40), and Winter 2 (weeks 41-52/53). The forwards can also be purchased as yearly contracts. The System Price is used as a reference price for the forwards and futures. It is also used as the reference price for the Nordic over-the-counter (OTC) market, which is a bilateral wholesale market. Due to possible differences between the System Price and the actual Area Price of the sales or purchases, this hedging mechanism is imperfect. To overcome this price differential risk, CfDs were introduced.

The futures contracts can be purchased as day, week and block contracts. The spectrum of contracts is updated dynamically every day. The week contracts are split into day contracts seven days before the delivery period starts, while the block contracts are split into week contracts four weeks before the delivery period starts. The new block contracts are issued one year before delivery. The time horizon for futures is 8-12 months.

Besides the Nord Pool markets there exists a bilateral market for OTC contracts. In this market the most common contract types are forward contracts with different (fixed) load profiles, options and forward contracts with flexibility in the load profile (load factor contracts).

The balancing market at Nord Pool is called Elbas. In this market the players can trade one-hour contracts until two hours before real time. It is currently only available in Sweden and Finland. Deviations from generation and supply in the spot and the Elbas markets are managed by trading in the real-time market operated by the transmission system operators (TSOs). The TSOs in the Nordic countries apply different rules for the calculation of the real-time prices and the clearing of the market.

The electricity is generated from different energy sources in the Nordic countries. Norway uses 99% hydropower, while Sweden has a mix of hydropower (mainly located in the north), nuclear power and conventional thermal power (located in the south). Denmark has mainly thermal power generation (89%), with an increasing share of wind power (11%). Finland has the same mix of generation as Sweden, but with a higher share of thermal and nuclear power than hydropower. Due to the high share of hydropower in the Nordic system, production can vary from a dry to a wet year with an order of magnitude of 40 TWh. The hydropower production is easily regulated, and can show substantial differences during the day. For this reason the transmission requirements can vary greatly. There is also a considerable load growth in the Nordic area (1.55% pa. during the 90's). On cold winter days with high peak-load, the system can be capacity constrained, resulting in hours with high prices (up to 1500 NOK/MWh). For more information on the Nordic power market, see Nord Pool (2002).

3. Transmission pricing and congestion management

The ideal tariff for trading arrangements in deregulated markets should have the following properties:

- Market players should know their locational transmission cost.
- The transmission costs should be independent of the location of the trading counterpart.

Below we describe the main features of Nordic transmission pricing.

3.1 Nordic transmission pricing

The point-of-connection tariff is used in transmission pricing in the Nordic region. The Nordic tariffs give full access to the Norwegian, Swedish, Danish and Finnish markets. The tariffs have substantial differences, but it is possible to accomplish market transactions across national borders of connection, because of the properties of the point tariff. An essential property of this tariff is that it should not be an obstacle to free trade or restrict a player's ability to choose counterparties (thirdparty access -TPA). During the transition period, prior to a common Nordic market, border tariffs have been charged. The tariffs have been volume-dependent and have mainly been based on reciprocity, to make the competition fair on both sides of a

[1] Currently the System Price is the price cross between total bids and offers in Norway, Sweden and Finland. Bids/offers in the Danish areas are also included in the calculation up to the capacity limits to or from these areas. Beginning January 2006 the System Price will include Denmark West and Denmark East.

border.

The rates for injections into and withdrawals from the grid are different. The geographic location within the transmission grid also affects the rates. Cumulative tariffs require that the players pay the sum of the tariffs levied, including the high-voltage national network, down to lower-voltage local distribution grids. The main principles of the cumulative tariff rates are:

- Main-grid tariffs must fairly reflect the main grid's total costs.
- Regional-grid tariffs must fairly reflect total regional-grid costs, plus utilization of the main grid.
- Local-grid tariffs must fairly reflect local-grid costs, plus utilization of the regional grid.

Main-grid tariffs are complex since they include several cost components. Local-grid tariffs can be simple, including only an annual connection fee and a volume-dependent fee.

Losses in the Nordic grid are treated as TSO consumption. The TSOs have to purchase grid losses in the spot market or from the bilateral contract market. The associated costs are recovered through the transmission tariff.

3.2 Market splitting, counter trade and constrained export/import

When congestion is predicted, two or more spot areas are defined. This procedure is called market splitting. It is used within Norway and at the border interconnections among the Nordic countries. In these cases the players must specify their bids in the different spot price areas. By the clearing at Nord Pool the prices in the different areas are decided such that the power flow does not exceed the specified constraints. A surplus area will then receive a lower price than a deficit area. The difference between the respective Area Prices and the System Price is called the Congestion Fee.[2] Market splitting gives price signals to the market players when there is scarcity of transmission capacity. The TSO receives an income from the market splitting, and therefore may have no incentives for expanding the grid.[3]

Statnett (the Norwegian system operator) defines the fixed price areas in Norway according to its information on the likely pattern of flows on the system for a certain period of time. The price areas are named as NO1 and NO2. When necessary additional price areas may be utilized. Sweden (SE) and Finland (FI) constitute one price area each, Denmark two (west DK1 and east DK2), and Norway constitutes two or three areas. In total there are six to eight (depending on the number of areas in Norway) price areas in the Nordic region. Congestion inside the price areas is managed by counter trade. Congestion between the countries can also be handled by constrained import/export. The bottleneck west of Oslo is managed by restriction of export to Sweden. In Sweden, Jutland, Funen, and Zealand there is counter trade after a restriction of import/export is conducted. In Finland there is only counter trade with the exception for unexpected events. Among all countries counter trade occurs when the real time physical flow is approaching the maximum transmission limit.

The bids in the balancing market are first meant to balance the power system (frequency control), but because they contain geographical information they can be used to manage congestion. If the power flow through a bottleneck exceeds the allowed limit, the TSO orders increased production (upward regulation) within the constrained area and decreased production (downward regulation) in the surplus area. This is counter trade, and it involves an expense for the TSO. The price paid for increased production is always higher than or equal to the System Price, while the price for decreased production is lower or equal. Downward and upward regulation is rewarded with the difference between the System Price and the price in the real-time market. The increased production (or decreased consumption) must occur in the area with the more expensive production, and the decreased production (or increased consumption) must occur in the area with cheaper production. The costs associated with counter trade over time can give the TSO incentives to expand the grid, and thereby reduce the costs. The counter trade gives one market with a uniform price, which promotes electricity trade. If the price differences are not allowed to last for some time, an extended utilization of counter trade can interfere with the price signals from scarcity of transmission capacity.

It is important to distinguish between a thermal producer and a hydropower producer with regulation ability when transmission congestion is analysed. Water can be stored and used later for production. When a bottleneck is predicted and has a certain period of duration, the congestion management methods have different impacts on the use of water. Spillage involves lost energy production and local low prices, if market splitting is used. The producers will earn more money by producing more before the bottleneck settles. With counter trade the producers can adjust as though there is no congestion. In a situation where the export capacity from an area is constrained, the producers are paid the System Price for their production. In addition they can participate in the counter trade arrangement. They avoid low Area Prices at the same time they are being paid for the water not produced because of transmission constraints. This weakens the incentives for avoiding spillage.

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[2] Statnett (the Norwegian system operator) uses the term "Capacity Fee" (Norwegian: kapasitetsavgift).

[3] To what extent the system operator keeps the congestion rent depends on the economic regulation of the grid company. With the current regulation in Norway (revenue cap regulation) the congestion rent adds nothing to the net revenue of the system operator.

3.3 Historical Area Price differences

The Norwegian Water Resources and Energy Directorate (NVE), which is the grid company regulator in Norway, believes that market splitting is the most efficient method to handle planned and persistent bottlenecks due to the grid's structure and the varying reservoir levels (Norwegian Competition Authority, 2000). Small temporary bottlenecks due to failures, outages, and maintenance of the network are better handled by a counter trade arrangement.

Since January 2000 NVE has introduced a test scheme with fixed price areas. The division of the areas will be reassessed before each season and will be fixed thereafter. Within the areas, congestion will be managed by a counter trade arrangement unless the costs associated with one bottleneck are higher than a specified cost.

Table 1 shows the yearly average prices for 1996-2001. As can be seen, the Oslo, Stockholm and Helsinki prices for 2001 were below the System Price. The Oslo price has on average been below the System Price since 1998. Conversely, the Århus and Copenhagen prices have been above the System Price since 1999 and 2000 respectively. This has implications for the electricity trading between the Nordic countries. For example, a trade of 100 GWh between two locations with a price differential of 5.26 NOK/MWh implies a Congestion Fee of 526100 NOK.

Table 2 shows the percentage of the years, in which the Area Price differed from the other Area Prices. Historically there has been a substantial percentage of the year with price differences, especially for the NO1, NO2 and DK1 areas.

4. Forward pricing theory

It is possible to use two different theories for pricing of forwards and futures (Fama and French, 1987). The first theory describes the current forward price as the expected spot price, plus a cost of storage and minus a convenience yield. The second theory states that the forward price is equal to the expected future spot price discounted at the risk premium for the holding period. We will discuss both of these theories and how they can be used for pricing of electricity forwards and futures. Our discussion is based on the references Botterud *et al*. (2002), Clewlow and Strickland (2000), Leong (1997), Pindyck (2001) and Schwartz (1997). We will discuss briefly risk premiums in pricing of commodities after presenting both theories.

The traditional financial markets use the no arbitrage models for valuation of the forward prices. The models show a relationship between the spot and forward prices by the possibility of arbitrage between the prices. Since it is easy to buy and sell the underlying asset, the argument of no arbitrage can be used.

However, in electricity markets, the no arbitrage models are not useful because they depend on whether a commodity can be stored. This is the opposite of storable commodities, where inventories play an important role in the price formation (Pindyck, 2001).

The cost of carry relationship states that the pay-off to a forward sale of an asset can be replicated by borrowing money for the purchase in the cash market, holding the asset until maturity, and then delivering the asset into the long position, using the funds received to pay off the loan. This relationship holds in markets where arbitrageurs are able to purchase and short sell assets easily.

For some participants holding the underlying asset has value relative to having the forward contract. The value has been termed the convenience yield. It can be represented in terms of an effective continuous dividend stream δ which the holder of the spot asset receives. The convenience yield also reflects the market's expectation about the future availability of a contract.

Let $F(t,s)$ be the price of a forward contract at time t and with maturity time s (i.e. the life of the forward position is $s-t$) on a spot asset that is currently trading at the price $S(t)$. Taking into account the cost of carry relationship and the convenience yield, the pricing formula for a forward is:

$$F(t,s) = S(t) \cdot e^{(r+w-d)(s-t)} \quad (1)$$

where r is the financing cost assuming continuous compounding, over the life of the forward position, s-t, and w represents the cost of storage over the holding period.

This formula can determine some interesting relationships between the spot and the forward price. Depending on the relative magnitude of the interest rate (positive), the cost of the storage (positive) and convenience yield (negative) the forward price will be less, equal to, or greater than the expected future spot price. The forward curve is said to be in contango when the forward price is greater than the expected future spot price implying an upward sloping (contango) forward curve as illustrated in Fig. 1. When the forward curve is downward sloping (backwardation) the forward price is less than the expected future spot price.

Often it is impossible to sell the underlying asset short and thereby execute arbitrage. In the presence of backwardation the market players should buy the forward contract at a discount to the spot price.

The electricity storage problem implies non-uniqueness of forward prices, which means that the market is incomplete. The characteristics of incomplete markets are heavy tails, autocorrelation, skewness and illiquidity.

The second theory for pricing of forward contracts takes into account an investor's risk preference. The price of a forward contract is equal to the expected (E) future spot price and discounted at the risk premium at the time s. The commodity risk premium, $v = -(r - f)$, is equal to the difference between the investor's discount rate f and the risk-free interest rate r. The risk premium must be interpreted in the light of the risk preference and the market share of the supply and demand side. The theory states that a risk-averse investor would require a positive risk premium for a future investment, while the opposite holds true for a risk-seeking investor. The forward price can now be expressed as:

$$\begin{aligned} F(t,s) &= E(S(s)) \cdot e^{(r-f)(s-t)} \\ &= E(S(s)) \cdot e^{-v(s-t)} \end{aligned} \tag{2}$$

The forward-spot price relationship can be analysed depending on the sign of v. A positive risk premium for a producer implies that the forward prices are lower than the expected future spot price. Conversely a negative risk premium for the consumer implies that the forward prices are greater than the expected future spot price. Several implications can be drawn, depending on the roles of the players (i.e. producers or consumers) and the dominance in the market. If the market player is a risk-averse producer it may want to hedge its production in the forward market. A market with dominant risk-averse producers will involve a forward market in backwardation. On the other hand, if the risk-averse consumers are the dominant players, this would imply a market in contango.

The risk premium can also be explained by considering the correlation between the forward price and the spot price. If the two prices are positively correlated this involves a positive systematic risk. Thus an investor would require an expected return above the risk-free interest rate.

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 averseness varies considerably between the two sides.

The share of producers and consumers in the forward market can be assumed to be relatively equal, since many companies have both generation and load. Concerning the capability of adjusting the quantity of supply and demand there are differences. The demand of electricity is relatively inelastic, while the generators have much more flexibility in regulating the produced quantity, especially the hydropower producers that can regulate their production in a short period of time. For these reasons the producers may not want to hedge their production in the forward market. The generators can use the available information to optimise their production in accordance with the hours with the highest prices in the day-ahead spot market and in the real-time market. On the other hand, if the consumers are risk-averse they may want to hedge their future consumption in the forward market by being willing to pay a risk premium for the future asset.

The sign of the risk premium can also be dependent on the supply and demand of forward contracts. If there is an excess supply of contracts this would imply a positive risk premium, while an excess demand would imply a negative risk premium.

In the context of a forward contract on the difference between the Area Price and the System Price, the risk premium theory will have the following interpretations. If the price differential in a given area is positive, the consumers are penalized if they have purchased a forward contract related to the System Price. They are risk-averse if they pay for the contract at a price greater than the expected price differential. If the price differential is negative, generators are penalized, and they are risk-averse if they pay for a contract that is more expensive than the expected price differential (in absolute value).

The CfD is settled against the difference between the Area Price and the System Price, while the forward contract itself is priced based on the market's expectations about the future spot prices. The risk premium model can then be formulated as:

$$\begin{aligned} CfD(t,s) &= E(AP(s) - SP(s)) \cdot e^{(r-f)(s-t)} \\ &= E(AP(s) - SP(s)) \cdot e^{-v(s-t)} \end{aligned} \tag{3}$$

where *AP(s)* and *SP(s)* are the future Area and the System Prices. The difference is that expected spot price now is a difference which is typically more volatile than a single spot price. In general there will be different risk-premiums for different areas. A hydropower area like Norway (in a normal or wet year) will have an Area Price which is lower than the System Price implying a negative CfD price. Typically if the generators have sold most of their production as forward contracts referred to the System Price, they would be willing to pay a risk premium to hedge against the price differential. Conversely in a thermal area the Area Price would be greater than the System Price (with a corresponding positive CfD price), and load would be willing to pay a risk premium since it has to purchase power at the local price.

If forwards referring to Area Prices in the Nordic market existed we would have the following relationship:

$$\begin{aligned} CfD(t,s) &= FAP(t,s) - FSP(t,s) \\ &= E(AP(s) - SP(s)) \cdot e^{-v(s-t)} \\ &= E(AP(s)) \cdot e^{-v1(s-t)} - E(SP(s)) \cdot e^{-v2(s-t)} \end{aligned} \tag{4}$$

where *FAP(t,s)* and *FSP(t,s)* are the Area and the System Price forwards at time t and maturity s, and $v1$ and $v2$ are the risk premiums of the respective prices. The above equality would be true due to a no-arbitrage argument.

All other things being equal, the longer the duration of a forward/futures contract or the more forward it can be purchased, the greater the hedging benefits it contains. Conversely, a very short-term contract has limited value, since its returns will closely approximate those of the underlying asset. The cost of this contract should be correspondingly small.

Electricity markets generally exhibit complicated seasonal patterns. A peak is observed in winter due to the demand for heating. The spot price will also depend on the inflow to the reservoirs. There can be daily and hourly patterns, with less price variations in hydropower-dominant areas due to the high degree of controlling ability. The more complicated patterns are due to the non-storability of electricity. Another factor is that the electricity market is still a regional market. Differences among regions arise due to the different methods used to produce electricity, weather patterns, demographics, local supply and demand conditions, etc. Transmission lines between different regions help to reduce such problems but constraints on the lines mean that the problems do not completely disappear.

The markets for oil, gas and coal will be related to the electricity markets since these are used as fuel in thermal power plants. Empirical research carried out by Pindyck (2001), Fama and French (1987), Bodie and Rosansky (1980) and Chang (1985) on commodities futures prices finds evidence to support normal backwardation for petroleum and agricultural products, and portfolios of commodities. The risk premium may be time varying, but is not related to the general level of the stock market.

5. Major issues in trading of forwards and futures contracts

Forward and futures contracts are a means to transferring risk to those who are able and willing to bear it and allow investors to transfer risk to others who might profit. The party transferring risk achieves price certainty but loses the opportunity to make additional profits. The party taking on the risk loses if the counterparty's downside is realized. Except for transactions costs, the winner's gains are equal to the loser's losses.

According to Khoury (1984) a hedger is primarily motivated by the security and not the profit derived from the futures transaction. A speculator, on the other hand, is motivated by the profits that are achieved through the successful prediction of price movements in a futures transaction. An arbitrageur capitalizes on unjustifiable price differences (e.g. between two different markets) over space or over time (e.g. between one maturity month and another). Pure arbitrage involves zero risk and no commitment of capital. The activities of the agents will determine the futures prices.

The basis is the differential at a point in time between the futures price of a commodity and the spot price of the same commodity. Futures prices often exceed spot prices, but not always. The closer the spot price is to the higher futures price, the stronger the basis. A strong basis reflects excess demand for the commodity. In this case, the spot market is indicating its willingness to pay for earlier spot delivery. A weak basis indicates that the market is unwilling to make early "storage" payments.

Under uncertain conditions, speculators would buy or sell futures contracts, depending on whether their expectations about future prices coincide with the maturity of the contracts. If their expected price is greater than the futures prices they would be long on the futures contract. Conversely a short position would be established if the expected price is less than futures price. The hedgers would enter futures contracts to offset their current or expected cash position, independent of what the expected price is going to be. Hedgers are only interested in shifting the risk that results from price fluctuations onto the speculators. Those who make sure that the relationship between the futures prices and spot prices is in equilibrium are the arbitrageurs. Arbitrageurs tend to bet on more certain outcomes than on a forecast vs. a forward price. However, it would be easier to sell month *m* if it looks overvalued relative to *m-1*, because the bet can be hedged by buying *m-1*, and two prices one month apart can be expected to move together. It would be much harder for a prudent trader to sell month *m* based on a forecast of spot prices in month *m* showing it is overvalued. If the traders own the option to build a power plant, that option is also a hedge that allows one to sell forward. Given the methods of traders and arbitrageurs, can we expect a consistent bias in the forward market?[4] This issue is worth looking into.

6. Forward locational price differential products

The CfD is a forward market product with reference to the difference between the Area Price and System Price during the delivery (settlement) period.

CfD = average during the delivery period of
(daily Area Price – daily System Price) (5)

From this formula we see that every time the Area Price is higher than the System Price the holder receives a rebate equal to the price differential. Otherwise the holder must pay the difference in prices. The pay-off from a CfD is determined by calculating (5) during the settlement period and multiplying the price differential by the contracted volume. The price of these contracts is settled by the supply/demand drives.

New forward Area Price contracts could also have been introduced, but they would split the total liquidity among several products, and were therefore rejected.

The market price of a CfD during the trading period reflects the market's prediction of a price differential during the delivery period. The market price of a CfD may be positive, negative or zero. CfDs are traded at positive prices when the market expects the Area Price to be higher than the System Price (a net import situation). CfDs will trade at

[4] Personal communication with power trader at Morgan Stanley, New York.

negative prices if the market expects an Area Price below the System Price (a net export situation).

A perfect hedge using forwards or futures contracts is possible only when the Area Price and the System Price are equal. If forwards or futures are used for hedging there is a basis risk equal to the difference between the Area Price and the System Price. To create a perfect hedge against the price differential, a three-step process using CfDs must be used:

1. Hedge the specified volume by using forward contracts.
2. Hedge against the price differential – for the same period and volume – by using CfDs.
3. Accomplish physical procurement by trading in the Elspot area of the holder of the contract.

In the Nordic market the term Contract for Differences differs from the corresponding term used in the British market. In the Nordic region CfDs are used to hedge against the difference between the two uncertain prices (Area Price and System Price), not as in the British market, against the difference between the spot price and a pre-defined reference price or price profile. The Nordic CfD is a locational swap, while the British CfD is settled based on the difference between the spot price and the reference price.

CfDs are also cleared at Nord Pool through Nord Pool Clearing, and it is assumed that the OTC volume is higher than the volume provided by Nord Pool's financial market. The clearing service provided by Nord Pool reduces the counterparty and payment risk associated with the contracts. The fact that Nord Pool is providing the clearing service may therefore increase the liquidity of the contracts.

Table 3 shows the OTC volume traded for the first three trading periods. The number in brackets is the percentage of the total volume traded for each season. The volume traded is as expected highest for the Winter 2 2001 contracts which have a longer trading period. The majority of the contracts traded are referred to Helsinki and Oslo. Most of the Winter 1 and Summer 2001 contracts are referred to Stockholm. No contracts referred to Copenhagen are traded OTC. The traded volume and the number of trades have increased during all trading periods, but more data is needed to reach a conclusion about liquidity. Accumulated volumes for the CfDs at Nord Pool were not reported at the exchange's Web page. The volume traded on Nord Pool's financial market is approximately one third of the total volume of cleared power, while the OTC volume constitutes the rest. Including the power cleared via Nord Pool, a total power volume of 2770 TWh was handled by the exchange in 2001. This is approximately seven times the yearly physical power delivery.

7. Pricing analysis

In this section we analyse the prices of the contracts with the technical information in Table 4. All seasonal contracts were traded in the periods 17.11-29.12.2000, 17.11.2000-30.04.2001, 02.01-28.09.2001 and 02.05-28.12.2001. The CfD referred to Eastern Denmark was introduced the 23th of March 2001. The 15th of June 2001 yearly contracts were introduced with a trading period extending to 21.12.2001.

Based on the available information from the Nord Pool we analysed how the CfDs were priced in the respective periods. The average traded prices and the standard deviations are calculated in Table 5.

The prices of Winter 1 2001 contracts are relatively stable with small standard deviation. The Århus contract has the highest prices and the Oslo contract the lowest prices (negative prices). This is in contrast to the prices of the Summer 2001 contracts which are relatively stable until the new year, when they decrease to a new level. The standard deviations for these contracts are relatively high and have the same order of magnitude as the contract prices. On average the Århus contract has the highest prices and the Oslo contract the lowest prices. The Winter 2 2001 contract prices start at a relatively high level and stabilize at a lower level in the spring and summer. The standard deviation for these contracts is of the same order of magnitude as the contract prices. On average the Helsinki contract has the highest prices while the Århus contract has the lowest prices. Concerning the prices of the Winter 1 2002 contracts, they start at a relatively low level and increase towards the end of the trading period. The standard deviation is as high as for the preceding contracts. On average the Copenhagen contract has the highest prices and the Århus contract the lowest prices.

The prices for the year 2002 contracts show the same trend as the Winter 1 2002 contracts, with relatively low prices in the summer, and increases towards the end of the trading period. Generally the standard deviation for these contracts is less than the contract price itself, except for the Oslo contract. On average the Copenhagen contract has the highest prices and the Oslo contract the lowest prices.

The willingness to pay is highest for the Århus contract in the seasons Winter 1 and Summer 2001. The willingness to pay is also relatively high for the Helsinki and Copenhagen contracts in all seasons. It is also interesting that the Oslo contract have negative prices on average for all seasons and for the year 2002. This means that the buyers of these contracts are receiving money for holding these contracts, but they have an obligation to pay the difference between the Oslo price and the System Price, if it is negative during the delivery period.

Another interesting issue to study is whether the contract prices are over or under the value of the underlying asset (i.e. the daily average of the Area Price minus the

System Price during the delivery period). The calculations are shown in Table 5. The pay-off from the contracts is equal to the difference between price differential (Area Price minus System Price) and the average traded price. The contracts with positive pay-offs are shown in Table 6.

Table 6 shows that there is a positive pay-off from the Oslo contracts in the first two seasons. For the last two seasons there are relative high pay-offs for the Copenhagen and Århus contracts. All other contracts have negative pay-off on average (on average the forward price exceeds the spot price differential).

As mentioned earlier this can be interpreted as a negative risk premium for the risk-averse consumers (a forward market in contango). On the other hand a risk-averse producer would require a positive risk premium. The majority of our results are in accordance with the pricing of futures contracts at Nord Pool (Botterud *et al*., 2002), which also seem to be over-priced relative to the underlying asset. But for these contracts it is also relatively few years with data.

However, we find that some contracts on average are under-priced. According to the risk premium theory, this implies a dominance of risk-averse producers or an excess supply of forward contracts. The Oslo contracts are referred to a hydropower area. The producers are paid the Oslo price (on average lower than the System Price) for their production, while their financial contracts are referred to the System Price. This indicates that a majority of risk-averse producers want to hedge their production in the forward market.

The Århus and Copenhagen prices have on average been above the System Price since the introduction of these spot areas at Nord Pool. The production in these areas is mainly thermal and the spot prices are relatively high. It is reasonable to assume that the producers are less concerned about hedging their production. A considerable exchange of power between the Nordic region and continental Europe may affect the Area Prices in Denmark through transmission congestion. Traded combinations of CfDs to hedge against the Area Price differentials, could make it difficult to establish a direct link between the demand of a specific contract and the contract price.

The trading price should reflect the market's prediction of the price differential as defined in equation (5) during the delivery period. Table 5 shows that the prices vary from the underlying asset. This is not surprising, because unforeseen shocks during the settlement period (e.g. unexpected constraints due to plant, and line outages as well as relative demand in each region) are bound to occur.

The underlying asset is also highly volatile, even more than the Area and System Prices themselves. The magnitude of the standard deviation is several times the magnitude of the price differential. Since the underlying asset is expected to be uncertain, the traded forward contract may have incorporated this uncertainty in the price. Parameters used to calculate the security requirements were changed in January 2001, because they generally were too high. This affected the contracts referred to Helsinki, Stockholm, Oslo and Århus.

Forecasting transmission congestion is a difficult task. The information available to the market players is forecasts of the inflow, Area Prices and System Price. The reliability of these forecasts for a longer period than the closest weeks is relatively low. Since transmission congestion is highly dependent on the inflow situation (dry versus wet years), the hydrological balance in an area can be used as to measure the probability of congestion. Another analysis tool is the EMPS-model (Haugestad and Rismark, 1998), which is used for optimisation and simulation of hydro-thermal systems with a considerable share of hydropower. The model takes into account transmission constraints and hydrological differences between major areas or regional subsystems. The objective is an optimal use of hydro resources in relation to future inflows, thermal generation, electricity demand and spot transactions within or between the areas. The weakness of the model is its grid representation that may be inaccurate. A precise description of the Nordic power system requires a model with frequently updated data.

8. Policy issues

Energy policy affects derivatives mainly through its impacts on the underlying commodity and transmission markets (Energy Information Administration, 2002). Electricity markets with large numbers of informed buyers and sellers, each with objectives of moving the commodity to where it is needed, support competitive prices. Derivatives for managing local price risks are then based on the overall market price with relatively small, predictable adjustments for moving the electricity to local users. Energy policy affects competitors' access to transmission, the volatility of transmission charges, and therefore derivative markets.

Efforts to reduce price volatility have focused on increasing both reserve production capacity and transmission capability. There has also been an effort to make real-time prices more visible to users to help limit the size and duration of price spikes.

Competitive electricity markets require competitive, reliable transmission markets. A network with sufficient capacity to supply high price areas stimulates competition. However, creating competitive transmission markets has proven difficult. Competitive transmission charges are the marginal cost of moving power. For example in the US (except in a few locations) transmission charges are currently set arbitrarily with no regard to the marginal cost. Many states actively discourage transmission of their cheap power to higher cost areas in neighboring states. The result is a fragmented market, where trade does not create consistent electricity prices.

Some barriers to the development of the electricity derivatives market are:

- As a commodity, electricity has many unique aspects, including instantaneous delivery, non-storability, an interactive delivery system, and extreme price volatility.
- The complexity of electricity spot markets is not conducive to common futures transactions.
- There are also substantial problems with price transparency, modeling of derivative instruments, effective arbitrage, credit risk, and default risk.

Because there are problems with the price models, innovative derivatives based on something other than the underlying energy spot price (e.g. weather derivatives, marketable emissions permits, and specialty insurance contracts) will be important in the future. Forward contracts using increasingly standardized terms are likely to be supplied in addition to futures contracts.

The Nordic region has a mature and liquid forward and futures market. There is confidence in Nord Pool which is owned by the Norwegian and Swedish TSOs. There has been 60-70% annual growth in the financial market in recent years (Nord Pool, 2002). The regulatory framework has been committed to facilitate trade and establish a liquid spot market. Nord Pool gives easy access to information and provides price transparency. Large industrial consumers and generation companies may therefore hedge their consumption/generation and decrease their risks. Nord Pool issued CfDs to hedge against the price differences resulting from transmission congestion. The market prices of these contracts indicate the market's expectation of transmission congestion. For long-term contracts it may provide information about the value of building a transmission line between two regions.

In continental Europe the electricity exchanges are less liquid and traders have to rely more on the OTC markets for hedging. To purchase physical transmission capacity, players may participate in cross-border auctions. They have during the last years established a method to allocate cross-border transmission capacity in cases where demand exceeds supply. The price of transmission capacity can be highly volatile (E.ON, 2003).

The PJM and New York power markets have financial transmission rights. These forward contracts are purely financial and entitle the holders to a payment equal to the future difference in locational prices times the contractual power. The independent system operator issues these contracts. They are supposed to redistribute the congestion rents the system operator collects during congestion. In the Nordic market the CfDs have no connection to the congestion rent the system operator collects.

9. Conclusions

This paper has demonstrated how Nord Pool prices the CfDs for the first five trading periods. Based on a comparison between the trading prices of the contracts and the average of the seasonal Area Price minus the System Price during the settlement period (except year 2002), they appear to be over-priced on average ex post. The explanation may be the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential. If the price differential in a given area is positive, the consumers are penalized if they have purchased a forward contract related to the System Price They are risk-averse if they pay for the contract at a price greater than the expected price differential. If the price differential is negative generators are penalized, and they are risk-averse if they pay for a contract that is more expensive than the expected price differential (in absolute value).

Our findings included contracts that were under-priced ex post. For the Oslo contracts this may be explained by the presence of a majority of risk-averse hydropower producers wanting to hedge their production in the forward market. The prices of the contracts depend on the inflow in the actual year which is an important factor in creating transmission congestion. Since every contract is referred to a season or a year, this makes the present amount of data limited. To our knowledge this is the first survey of how financial instruments for hedging transmission congestion risks have been priced.

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Table 1
Average yearly Area Prices (NOK/MWh) for 1996-2001

Year	System Price	Oslo (NO1)	Tromsø (NO2)	Stockholm (SE)
1996	253.74	256.79	251.40	250.80
1997	135.28	137.77	133.24	133.23
1998	116.92	116.48	116.75	114.75
1999	111.97	109.00	119.43	113.06
2000	103.21	97.55	100.56	115.38
2001	186.49	185.95	188.55	184.16

Year	Helsinki (FI)	Copenhagen (DK2)	Århus (DK1)
1998	116.76		
1999	113.64		122.44
2000	120.61	138.03	133.20
2001	183.98	189.72	191.21

Table 2
Percentage of the years, in which the Area Price differed from all other Area Prices

Year	Oslo (NO1)	Tromsø (NO2)	Stockholm (SE)	Helsinki (FI)
1998	22.9%	23.1%	3.2%	
1999	33.2%	36.6%	0.6%	4.0%
2000	55.0%	41.7%	5.5%	15.8%
2001	8.9%	23.8%	0%	0.9%
Year	**Copenhagen (DK2)**	**Århus (DK1)**		
1999		33.8%		
2000	7.2%	44.8%		
2001	5.4%	19.1%		

Table 3
Traded volumes of CfDs

Volumes OTC (GWh)			
Reference area	Winter 1 2001	Summer 2001	Winter 2 2001
Århus (DK1)		161.6 (4.5%)	541.2 (19.1%)
Helsinki (FI)	43.2 (7.3%)	918.0 (25.7%)	788.6 (27.0%)
Oslo (NO1)	28.8 (4.9%)	844.6 (23.7%)	1581.6 (38.3%)
Stockholm (SE)	518.2 (87.8%)	1645.1 (46.1%)	1115.5 (13.1%)
Total	590.2	3569.2	4126.4
Number of trades	7	48	62

Table 4
Product specification for the CfDs

Product-series	Contract hours	Trading period	Settlement period
Århus (DK1), Helsinki (FI), Oslo (NO), Stockholm (SE), Winter 1 2001	2879	17.11-29.12.2000	01.01-30.04.2001
Århus (DK1), Copenhagen (DK2), Helsinki (FI), Oslo (NO), Stockholm (SE), Summer 1 2001	3672	17.11.2000-30.04.2001	01.05-30.09.2001
DK1, DK2, FI, NO, SE Winter 2 2001	2209	02.01.-28.09.2001	01.10-31.12.2001
DK1, DK2, FI, NO, SE Winter 1 2002	2879	02.05.-28.12.2001	01.01-30.04.2002
DK1, DK2, FI, NO, SE Year 2002	8760	15.06-21.12.2001	01.01-31.12.2002

Table 5
Data concerning the prices of the CfDs analyzed and the value of the underlying asset

Winter 1 2001 (2879h)	**Average traded price (NOK/MWh)**	**St. dev.**	**Average of (AP-SP)**
Århus (DK1)	**15.39**	**1.67**	**-4.55**
Helsinki (FI)	**10.44**	**0.61**	**-0.77**
Oslo (NO1)	**-4.56**	**0.48**	**-0.16**
Stockholm (SE)	**8.82**	**0.88**	**-0.19**
Summer 2001 (3672h)	**Average traded price (NOK/MWh)**	**St. dev.**	**Average of (AP-SP)**
Århus (DK1)	**15.09**	**14.69**	**9.05**
Copenhagen (DK2)	**3.08**	**1.41**	**-3.18**
Helsinki (FI)	**6.62**	**5.02**	**-7.07**
Oslo (NO1)	**-1.98**	**1.85**	**-0.25**
Stockholm (SE)	**3.61**	**4.02**	**-7.12**
Winter 2 2001 (2209h)	**Average traded price (NOK/MWh)**	**St. dev.**	**Average of (AP-SP)**
Århus (DK1)	**-1.57**	**4.21**	**7.85**
Copenhagen (DK2)	**1.92**	**1.54**	**11.69**
Helsinki (FI)	**2.05**	**1.60**	**-1.25**
Oslo (NO1)	**-0.67**	**0.83**	**-2.35**
Stockholm (SE)	**1.12**	**1.21**	**-1.25**
Winter 1 2002 (2879h)	**Average traded price (NOK/MWh)**	**St. dev.**	**Average of (AP-SP)**
Århus (DK1)	**-3.06**	**2.02**	**7.10**
Copenhagen (DK2)	**4.78**	**4.15**	**15.33**
Helsinki (FI)	**2.86**	**1.46**	**1.01**
Oslo (NO1)	**-0.30**	**0.45**	**-0.69**
Stockholm (SE)	**2.16**	**1.98**	**0.97**
Year 2002 (8760h)	**Average traded price (NOK/MWh)**	**St. dev.**	
Århus (DK1)	**4.11**	**2.34**	
Copenhagen (DK2)	**6.28**	**3.57**	
Helsinki (FI)	**3.53**	**1.12**	
Oslo (NO1)	**-0.33**	**0.48**	
Stockholm (SE)	**2.22**	**1.26**	

Table 6
Positive pay-off contracts

Contract	**Pay-off (NOK/MWh)**
Oslo (NO1) Winter 1 2001	**4.40**
Oslo (NO1) Summer 2001	**1.73**
Copenhagen (DK2) Winter 2 2001	**9.77**
Copenhagen (DK2) Winter 1 2002	**10.55**
Århus (DK1) Winter 2 2001	**9.42**
Århus (DK1) Winter 1 2002	**10.16**

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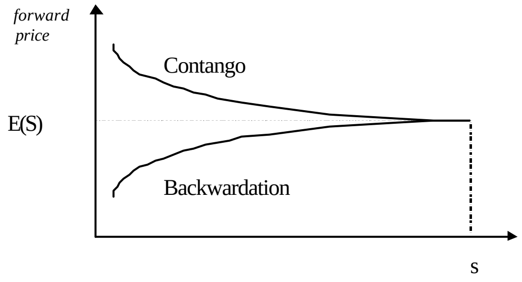

Fig. 1. Illustration of contango and backwardation in the forward market.