Efficiency of Contracts for Differences (CfDs) in the Nordic Electricity Market

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Abstract

This paper presents new and updated evidence on the efficiency of the EPAD contracts in the Nordic financial electricity market, based on a long sample of 14 years, from 2000 to 2013 inclusive. The Electricity Price Area Differentials (EPADs) are used to hedge against price differences between a bidding area and the Nordic system price. The aim of this paper is twofold. First, we estimate the magnitude and significance of ex-post risk premia in EPAD products (season, month, quarter, year) with delivery in 2000-2013. Further, we estimate the relationship between spot and futures prices by vector autoregression (VAR) model. By observing Granger causalities, adjustments to price shocks, and decomposing variance, we aim to shed light on the EPADs' efficiency. Second, we elaborate on some determinants of risk premia and test the roles of time-to-maturity and open interest on risk premia. We additionally consider, for the Nordic system an essential energy source, the role of water availability in the hydro reservoirs on explaining local area price spreads. We support and reject some of the earlier findings about the limited efficiency of the EPADs and bring new empirical evidence on the drivers behind the regional price dynamics.

Keywords: Efficiency; liquidity; derivatives; hedging; Nordic electricity market;

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1 Introduction

In Europe, the main reason for designing new energy market rules is to facilitate achievement of a well functioning European Internal Energy Market (IEM). This is often referred to as the Target Model for the electricity market and consists of rules governing relevant market time frames. These time frames are covered in the network codes on Electricity Balancing, Capacity Allocation and Congestion Management, and the Forward Capacity Allocation. In this setting the forward capacity allocation code stipulates the rules governing the auctioning of hedging instruments by TSOs enabling hedging of price differences. Financial and physical transmission rights, abbreviated FTR[1] and PTR respectively, are playing an essential role in shaping these market network rules (Rosellón & Kristiansen, 2013). Some of the key objectives behind introducing tradable transmission rights are promotion of efficiency in cross-border transmission infrastructure, promotion of cross-border competition in generation, mitigation of market power in generation, facilitation of investments in cross-border transmission capacity, risk allocation to TSOs, and accommodation of intermittent generation (Newbery & Strbac, 2011).

Currently, the European cross-border transmission is allocated by TSOs in a single price coupling algorithm based on marginal pricing principle in the day-ahead implicit auction (ACER, 2011). Much research has been devoted to Financial Transmission Rights, FTRs, that would result from an implementation of the above mentioned network codes (Buglione, et al. 2009; Füss, Mahringer, & Prokopczuk, 2013; Glachant, 2010; Wobben, 2009(Buglione, Cervigni, Fumagalli, Fumagalli, & Poletti, 2009; Füss, Mahringer, & Prokopczuk, 2013; Glachant, 2010; Wobben, 2009), whereas the role of FTRs in the Nordic setting has received much less attention as the Nordic market has an exemption from implementing the FTRs (Hagman & Bjørndalen, 2011; Kristiansen, 2004; Kristiansen, 2004; Marckhoff & Wimschulte, 2009).

In the Nordic market the EPAD[2] contracts, Electricity Price Area Differential, could fulfil the role of FTRs, i.e. they are used to hedge a basis risk arising from congestion between zones/nodes. There are two main differences between EPADs and FTRs in the current

[1] FTR is "*a financial contract to hedge source-to-sink (point-to-point) congestion and entitles its holder the right – or – obligation – to collect a payment when congestion arises in the energy market*" (Rosellón & Kristiansen, 2013).
[2] We refer to EPADs and CfDs interchangeably and treat them equally, depending mainly on the context and historical reference to each term.

setting. First, EPADs have no connection to congestion rent collected by TSOs/ISOs during cross-border congestion, whereas FTRs are issued directly by TSOs/ISOs which in this way redistribute the collected congestion rent (Kristiansen, 2004). Second, FTRs hedge price difference between bidding zones whereas EPADs hedge the price difference between bidding zone and a “reference” system price.

While much theoretical and empirical scrutiny has been devoted to efficiency of wholesale electricity markets (Growitsch & Nepal, 2009; Borenstein, Bushnell, & Wolak, 2002; Joskow, 2006), the efficiency and determinants of realized risk premia in forward markets remains less charted research area (Redl & Bunn, 2013). Risk premia are understood as a systematic difference between forward price and the realized delivery date spot price (Shawky, Marathe, & Barrett, 2003). Therefore, from price efficiency point of view, not only mark-ups in wholesale spot prices are of interest to market participants, but also the role and determinants of risk premia in forwards contracts deserve scrutiny.

An efficient market should not facilitate any significant arbitrage opportunities for strategic market players in a long-run. We aim to test the no-arbitrage condition on the case of Nordic EPADs by scrutinizing the price discovery process of individual contracts across all traded time horizons (seasonal, monthly, quarterly, yearly) and geographical locations (10 Nordic price zones) during the period 2000-2013. Our work aims to shed light on dynamics and determinants of locational price spreads in the day-ahead auctions, i.e. the difference between area prices and “reference” system price, and the EPAD as the corresponding financial contracts managing this type of risk. The goal is to estimate and explore the dynamic drivers of risk premia in EPADs and evaluate the market’s overall efficiency by studying the integration between spot and futures price.

1.1 Research background – factors affecting price efficiency

The drivers of different economic outcomes across electricity markets stem from multiple factors, among which are relative *production costs*, *fuel prices*, and *overall demand*. The geographical characteristics of Nordic electricity market, for instance, oblige researchers to account for the dominant role hydro power when considering any market efficiencies.

The impacts of long-term *contracts* and other *vertical arrangements* were also shown to lead to performance differences in electricity markets (Bushnell, Mansur, & Saravia, 2008; Christensen, Jensen, & Mollgaard, 2007). The more specific problem of evaluating efficiency of electricity derivatives market needs to take into account the unique characteristics of electricity[3] where classic arbitrage arguments do not hold for valuation of forwards and futures. This is because electricity contracts are delivered over time based on commodity flows (Wimschulte, 2010; Lucia & Schwartz, 2000). Yet, studies on efficiency of electricity futures and forward markets differ in conclusions. In the case of Nordic electricity market, Kristiansen (2007) finds inefficient pricing for month, season and year forwards, whereas Wimschulte (2010) finds no significant price differentials between futures portfolios and corresponding forward prices when transaction costs are considered.

Currently, the specific challenges of EPADs in the Nordic electricity market seemingly stem from the lack of sellers and wide price spreads in some price areas[4]. This situation could make it costly for suppliers to enter the market without having a physical production in it (Nasdaq OMX, 2014). Solutions to these problems are not yet in place, however ENTSO-E's network codes on Capacity Allocation and Congestion Management (CACM) and Forward Capacity Allocation (FCA) aim to build *transparency* via standards for harmonizing the rules across market borders. Among the discussed solutions of managing spatial price risks are auctioning of FTRs/PTRs or EPADs (Johansson & Nilsson, 2011). The general trend is to enable TSOs auction cross-border hedging products to aid *liquidity* and *transparency* hence overall market efficiency[5].

Liquidity is a factor in forward electricity markets that impacts efficiency by affecting transaction costs, price discovery process, and speed of adjustment to fundamental information. Market participants desire to quickly find trading partners with whom to enter into or exit from contractual positions without adversely affecting asset's price (Sarr & Lybek, 2002, p. 4). Liquidity is affected, among others, by market design, maturity as well as market concentration (ACER, 2014, p. 14). Different measures of liquidity in electricity markets exist, such as churn rates or open interest. The churn rate is a ratio between the volume of all trades in all timeframes executed in a given market and its total demand

[3] Non-storability, constant balance of supply and demand, , physical interconnection between customer and producer, somewhat limited demand elasticity
[4] The market can be characterized as thin but deep in Sarr and Lybek (2002, pp. 5-6) terms. Breadth implies number of participants (thin vs. broad) and depth implies the existence of abundant orders (deep vs. shallow)
[5] Growitsch and Nepal (2009) argue that transparency and liquidity are the major means of fostering efficiency in the electricity wholesale market.

(ACER, 2014, p. 13)[6]. The open interest represents a number of open contracts which have not yet been liquidated either by an offsetting trade or an exercise or assignment (Nasdaq, 2014). In addition, bid-ask spread may also be considered as a direct measure of liquidity with more pronounced effects on transaction costs for market participants[7,8].

In sum, there are multiple fundamental risk factors affecting supply and demand sides in electricity markets that need to be considered when assessing efficiency of a specific hedging instrument such as EPAD. Next we present our research question, state main objectives and contributions.

1.1 Research Question, Objectives, and Contributions

Our key research question is: *What constitutes the risk premia in Electricity Price Area Differentials (EPADs) in the Nordic electricity marke*t? The underlining objective is to evaluate the efficiency of EPAD contracts in the Nordic electricity market for the period 2000-2013 by 1) studying significance, direction, and magnitude of risk premia according to location, delivery periods, and time-to-maturity, and 2) evaluating the effects of underlying fundamental factors on risk premia (liquidity, time-to-maturity, market size changes, and water availability in the hydro reservoirs). To reveal whether a long-term relationship between expected futures price of EPAD and the realized spot price of EPAD exists we estimate a vector autoregression (VAR) model. This research design enables us to test long-term bi-directional Granger causality between the two price series and their short-term response to price shocks by impulse response functions (IRF). We further decompose the sources of variation in the estimated VAR models and jointly derive conclusions relating to EPADs overall efficiency.[9]

Our main contribution lies in expanding the limited research on locational price risks in electricity markets and determining their drivers. We bring into the debate a new timeframe

[6] It can be understood as a number showing how many times a megawatt hour is traded before it is delivered to the final consumer. Some stakeholders consider a churn rate of at least 3 to be a minimum value. The most liquid market in Europe, Germany, reaches on average a churn of 8.5

[7] The bid-ask spread may reflect (Sarr & Lybek, 2002, p. 9) i) order-processing costs; ii) asymmetric information costs; iii) inventory-carrying costs; and iv) oligopolistic market structure costs

[8] Other authors, such as Wimschulte (The futures and forward price differential in the Nordic electricity market, 2010, p. 4733) discuss the issue of liquidity between the futures portfolios and forwards.

[9] The comparison between the EPAD price and the realized spot price rests on the heroic assumption of perfectly rational expectations, that there are no hidden or private information in the price formation. We do not directly aim to test the efficient market hypothesis but would like to point out to the growing discussion on financial behavior that actually puts this assumption in question. However, we suggest that the methods we use could be a first indication of efficiency in a market.

(2000-2013) which is characterized by fundamental market changes, such as implementation of EU ETS, introduction of the 3rd Energy Package, and market size changes, i.e. inclusion of Estonia, Lithuania, Latvia and splitting of Sweden and Norway into multiple zones. We include the time period Marckhoff & Wimschulte (2009) had studied and expand both scale (sample size) and scope (additional drivers of risk premia). We consider the role of water availability in the hydro reservoirs on locational price spreads, and add the discussion on the role of liquidity (open interest) on risk premia. Also, we investigate whether EPAD risk premia are a negative function of time-to-maturity.

As a proxy to EPAD's efficiency, we finally estimate a vector autoregression (VAR) model of relationships between expected futures price of EPAD and the realized spot price of EPAD for each area and delivery period. We aim to test their long-term relationship by Granger causality tests and short-term adjustments to shocks by impulse response functions and variance decomposition. The application of VAR to evaluate market efficiency of EPADs is a contribution to empirical studies literature on derivatives pricing.

2 Risk management in the Nordic electricity market

Market actors within the electricity market face regular risks of changing input prices and varying demand in space[10] and time. In the future, it may be expected that intermittent power sources will contribute to increased volatility in prices thus to some extent accentuating these risks. In a well-functioning market, financial instruments to hedge risks should spontaneously arise when the values of the risks to market participants exceeds the individual participants preferred risk and opportunity exposure. Typically a producer may wish to lessen the volatility of earnings over time and retailers may want to control input costs, hence a market for an instrument achieving this would emerge. In electricity markets, one interesting feature is the physical connection between generation and final demand. Whenever there is a bottleneck in the system, underlying fundamentals and valuations create a pressure towards geographically differentiated prices (Bohn, Caramanis, & Schweppe, 1984; Stoft, 2002). Thus the risks in the electricity market are not only related to the actions of consumers or producers making choices of consumption or production. They also depend on infrastructure's availability and usage which also varies in time and space, depending on

[10] For example, if procurement and invoicing is done in different currencies the entity involved may want to control its currency exchange risk.

market and technical conditions. These temporal and spatial dimensions of the risk of future price development are intimately related to the availability of infrastructure.

In our study of the electricity market we deal with two main types of price risks[11]. First, what is the price going to be in the future (temporal risk)? Second, how often is the congestion going to cause price differences across bidding area borders (spatial risk)? In brief, the current Nordic electricity market handles these risks via two instruments. The future price risk can be managed by taking positions in forwards or futures instruments settled against the system price. The system price is the unconstrained Nordic price and is a price calculated without any congestion in the grid. This price is used for settlement of financial hedging instruments and not directly used in the spot market. The spatial price risk is dealt with by market splitting, i.e. situations when transmission capacity to deficit area is insufficient to equalize the price difference between adjacent areas at time *t*.

The second price risk can be denoted also as area price risk or basis risk, and is managed by Electricity Price Area Differential (EPAD) financial products. This type of instrument was introduced in Nord Pool in 2000. The underlying product is a forward contract on the future price difference between the area and system price in a specified period.[12] There are EPAD-contracts for months, quarters and the three coming calendar years.13 For the illustration of spatial dimension of the Nordic electricity market, see the map in Figure 1. The Nordic generation mix is heterogeneous throughout the different areas. Norway and bidding areas 1 and 2 in Sweden are mainly hydro. In Southern Sweden, bidding area 3, there is some hydro but mainly nuclear and CHP. The Swedish area 3 and the Finnish bidding area have strong similarities. The Finnish area has some additional run of river power generation in the North. Sweden south, bidding area, 4, only has thermal generation capacity. Denmark 1 and 2 has non-trivial amounts of wind power and thermal capacity. The Baltic States are currently mostly relying on thermal capacity.

[11] The market actor faces a variety of other risks e.g. the risk from making forecast errors making the actor pay or receive payment for imbalances in the settlement with the TSO.

[12] Historically listed CfD-contracts on Nord Pool are for the areas of Copenhagen (Eastern Denmark), Århus (Western Denmark), Helsinki (Finland), Stockholm (Sweden) and Oslo (South-Eastern Norway). In November 2010 NordPool listed CfD-contracts for the Norwegian area Tromsø and for the forthcoming Swedish bidding areas Luleå, Sundsvall and Malmö in November 2011.

[13] Seasonal contracts were traded from 2000 to 2005 and substituted by quarterly contracts. They were Winter 1 (January-April), Summer (May-September), and Winter 2 (October-December)

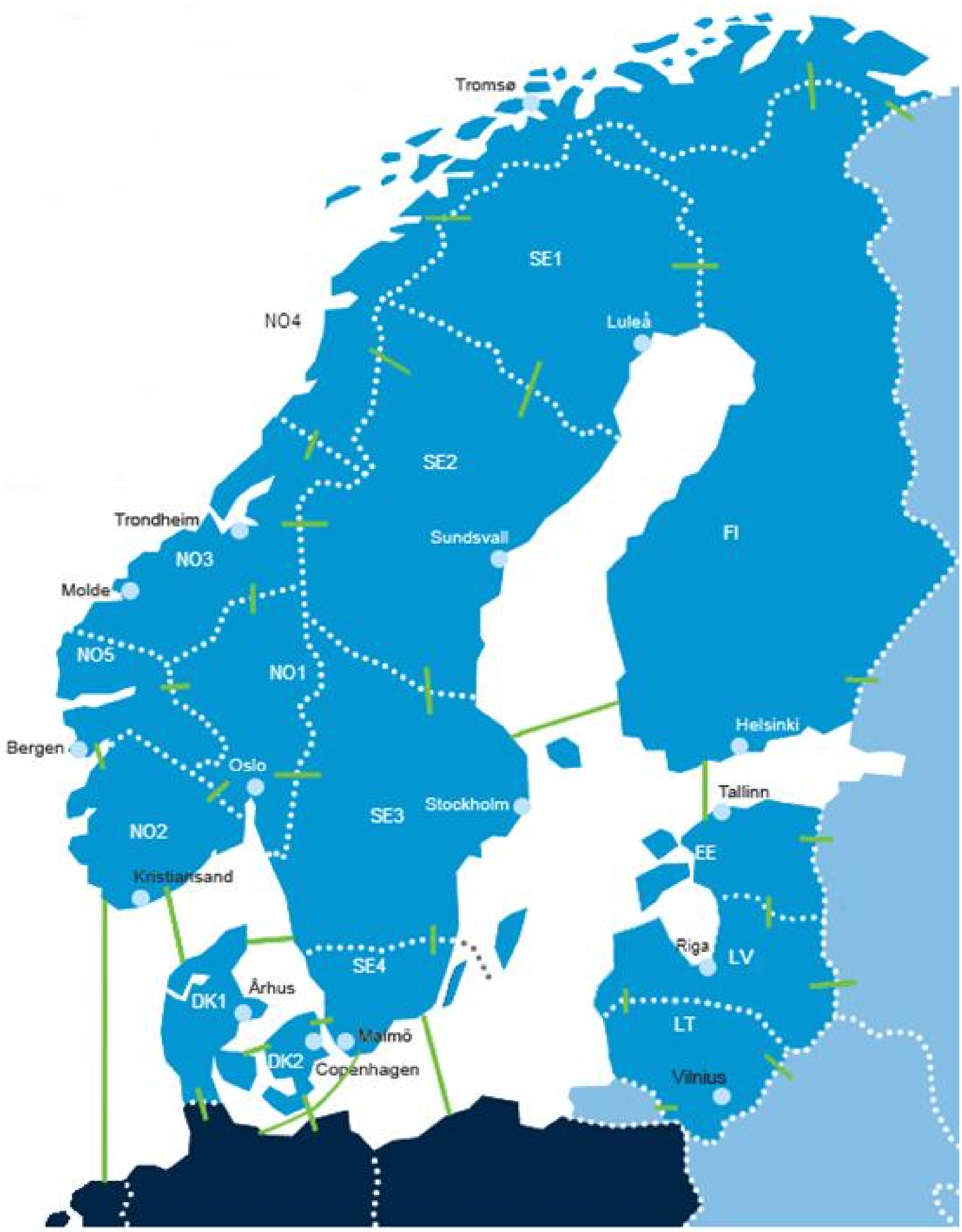

Figure 1 Map of the Nordic electricity market (Nord Pool Spot, 2014)

One distinct feature of the Nordic electricity market is its division into parts which are deregulated, with a free price formation, and the regulated distribution networks and transmission grids. If a plant is biding into Nord Pool Spot it has to manage the risk if it fails to physically deliver in real time, i.e. the participant has a balance responsibility agreement with the relevant TSO either directly or indirectly via another balance responsibility party. This is somewhat trickier on the demand side as there is only partial deployment of hourly metering (mainly at really large customers). Thus the retailers may know the price agreed to the customer but they do not know the exact quantity demanded. Additionally, the households are still in many cases charged according to predefined profile rather than actual consumption. Despite the increasing deployment of smart meters across the EU (80% by 2020), the price risks remain a pressing issue for retailers without hourly, or spot price based contracts with customers. The retailers thus hedge prices of customers fixed price contracts. This practice is clearly contingent on where the customers are located as, for example Norwegians are more prone to contracts with a variable price following Nord Pool spot than the Swedes (NVE, 2012).

The awareness of the European legislators that the regulated and deregulated parts of the electricity market are connected is slowly but steadily increasing. Thus the new EU legislation stipulates that the amount of transmission capacity should be present in either the financial markets e.g. financial transmission rights (FTRs) or be ensured by selling physical transmission rights (PTRs) (ENTSO-E, 2013) In the Nordic market there have been some worries that demanding the selling of FTRs would wreak havoc on the market design and in worst case undermine a well-functioning financial market (Hagman & Bjørndalen, 2011). This has led to the exemption (ACER, 2011, p. 10) under the condition unless "[…] appropriate cross-border financial hedging is offered in liquid financial markets on both side(s) of an interconnector".

3 Derivative pricing

Due to technical and economic limitations of electricity storability, the traditional theory of storage[14] is not applicable to pricing electricity derivatives. Instead, the price of electricity derivatives is determined by *expectations* and *risk preferences* of market participants[15]. Risk premia represent a premium (discount) that buyers (sellers) of futures contracts are willing to pay (accept) in addition to the expected future spot price in order to eliminate the risk of unfavourable future spot price movements (Marckhoff & Wimschulte, 2009, p. 263). This

[14] Theory of storage – the difference between today's spot and futures prices (Marckhoff & Wimschulte, 2009, p. 262) while considering interest rate (interest forgone), storage costs, and convenience yield (Kaldor, 1939; Working, 1948)

[15] This approach to pricing derivatives introduced by Cootner (1960), Dusak (1973), Breeden (1980)

approach states *ex-ante*[16] that the futures price $F_{t,T}$ is determined by the expected future spot price $E(S_T|\boldsymbol{\Omega}_t)$ and risk premia π_t^F where $\boldsymbol{\Omega}_t$ is the information set available at time *t*.

$$F_{t,T} = E(S_T|\boldsymbol{\Omega}_t) + \pi_t^F \qquad (1)$$

It is a common practice in forward and futures pricing litereatrue (equity, foreign exchange, fixed income derivates) to calculate the ex-ante premium in the forward price as *ex-post* differential between futures prices and realized delivery date spot prices (Shawky, Marathe, & Barrett, 2003). Longstaff and Wang (2004) suggested this *ex-post* approach to risk premia by using S_T as a proxy for $E_t(S_T)$, and Marckhoff and Wimschulte (2009) applied this proxy to calculate the ex-post risk premia for EPADs. In our study, we too embrace the ex-post approach to risk premia.

More specifically, during each day of the delivery period, the holder of long EPAD position receives a *payoff* which is similar to receiving the area spot price and paying the system spot price. Kristiansen (2004) sees ex-post risk premia as the difference between average CfD prices and the average difference between area and system price during the delivery period. Another ex-post approach employed by Marckhoff & Wimschulte (2009) is to examine risk premia on daily basis instead of averaging ex-post premia. The latter approach thus enables assessment of CfD's development throughout the contract's duration. In detail, CfD risk premium at time t for delivery at T = price of CfD contract on time t for delivery at T – the expected price (expected at the present moment t) of CfD contract on time T for delivery at T. More formally, as Marckhoff and Wimschulte (2009, p. 263) specify:

$$\pi_t^{CfD} = CfD_{t,T} - E_t(CfD_{T,T}) \qquad (2)$$

CfD risk premium at time t for delivery at T = CfD price on time t for delivery at T – average realized difference between the area price and the system price during the delivery period between T_1 and T_2.The premium for each delivery period (year/month/quarter/week) and area is computed separately. For practical purpose/empirical research**,** the following CfD payoff formula is used:

$$\pi_t^{CfD} = CfD_{t,T} - \frac{1}{T_2 - T_1}\sum_{h=T_1}^{T_2}(P_h^{Area} - P_h^{System}) \qquad (3)$$

[16] the well-known interpretation of futures prices as expected spot prices at maturity under a suitably chosen (possibly non-unique) risk-neutral measure Q (Cox and Ross, 1976; and Harrison and Kreps, 1979) still holds { also for electricity (Füss, Mahringer, & Prokopczuk, 2013, p. 15)

where π_t^{CfD} is the risk premium;

$CfD_{t,T}$ –closing price of the CfD contract on day *t* for delivery in period *T*;

P_h^{Area} and P_h^{System} – spot area and system prices, respectively, at hour h;

T_1 and T_2– start and end of the delivery period, respectively;

$T_2 - T_1$ = duration of the delivery period, in hours.

For an additional overview of empirical studies dealing with spatial price risks in spot and forwards electricity markets, see Table 1. Quick glance at time frames of the listed studies underlines the scale and scope of our sample (2000-2013) which also aims to validate the findings of earlier studies illustrated on shorter time periods.

Table 1 Summary of studies on spatial price risks in electricity markets

Study	Region	Model	Data	Results	Time frame
(Marckhoff & Wimschulte, 2009)	Nordic	Electricity forward pricing model; ex-post calculation of risk premia	Daily baseload prices as underlying of 251 CfD contracts with monthly, quarterly, seasonal and yearly delivery periods	CfDs contain adequate risk premia reflecting market efficiency; hydropower significantly impacts area price spreads; risk premia positively (negatively) related to skewness (variance) of spot price	2001-2006
(Haldrup & Nielsen, 2006)	Nordic	Regime-switching long-memory model	Hourly area spot price studied in non-congested and congested time periods depending on direction of congestion	Price dynamics and long memory of price differ across areas; fractional cointegration	3 January 2000-25 October 2003
(Worthington, Kay-Spratley, & Higgs, 2005)	Australia	Multivariate GARCH	Daily spot prices on half-hourly basis;	NEM regional spot markets are nonintegrated and inefficient; presence but no mean spillovers of price volatility between areas; shocks in on market affect price volatility in another market	13 December 1998 – 30 June 2001
(Hadsell & Shawky, 2006)	US-NYISO	GARCH	Day-ahead and real-time market prices; daily average aggregation of peak hour prices (7am-11pm); MC congestion; MC losses	Price volatility higher in real-time market than day-ahead; premium levels across zones inversely related to levels of congestion	Jan 2001-June 2004
(De Vany & Walls, 1999)	US- west	Vector error correction and cointegration analysis (VECM)	peak and off-peak electricity spot prices	Efficient and stable power market	1994-1996
(Longstaff & Wang, 2004)	US-PJM	Vector autoregressive model (VAR)	Daily average of hourly spot prices; day-ahead electricity forward price; electricity load and weather conditions	Risk premia of electricity futures are positive, but vary; forward premia are negatively related to price volatility and positively related to price skewness	June 1 2000-November 30, 2002
(Kristiansen, 2004)a	Nordic	Electricity forward pricing model; ex-post calculation of risk premia	Seasonal CfD contracts	Most CfDs contain significant risk premia (difference between average CfD prices and the average difference between area and system price during delivery); positive premia attributed to risk-averse consumers, whereas negative premia attributed to risk-averse hydro-producers.	November 2000 – April 2002
(Kristiansen, 2004)b	Nordic		Seasonal and yearly CfD contracts		November 2000 – December 2003

4 Data

The data used in this study directly originate from Nord Pool Spot (physical market) and Nasdaq OMX Commodities (financial market), and cover years 2000 to 2013. In the Nordic electricity market, congestion between bidding areas is a common feature serving the purpose of signalling scarcity in transmission capacity. The price divergence between reference system price (assumed unrestricted electricity flow across the whole market) and area prices is observable in both daily and hourly frequencies, as shown in Table 2. Throughout the time and across bidding areas, there is slightly increasing tendency of congestion, where approximately 95 % of days and 90% of hours in a year area prices decouple from the theoretical system price. On the one hand, mean Elspot wholesale system and area prices[17] follow jointly slightly increasing price trend[18] with peaks in 2006, 2008, and 2010 (corresponding to low hydro reservoirs in Norway, Sweden, and Finland, see section 6.1). On the other hand, the price volatility, measured by standard deviation, is highly location-dependent. Areas with the highest mean volatility are, in the order of magnitude, DK2 Copenhagen, DK1 Århus, and FI Helsinki. Therefore, we would expect to see the highest hedging pressures from producers and retailers in these areas, with correspondingly higher risk premia in absolute terms.

Table 2 Frequency of decoupled area prices from system price as a percentage of days and hours () in a year

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Mean
DK1	99,5 (80,3)	92,3 (48,9)	98,1 (66,5)	99,2 (78,3)	99,5 (78,2)	97,5 (70,4)	99,7 (79,7)	98,9 (81,6)	100,0 (96,2)	99,5 (85,7)	98,6 (88,1)	97,0 (82,4)	99,2 (86,3)	99,5 (87,1)	98,5 (79,3)
DK2	98,1 (89,8)	81,1 (41,9)	77,3 (47,4)	86,0 (62,5)	98, 6 (72,1)	85,2 (52,6)	99,7 (79,4)	98,9 (81,4)	100,0 (96,0)	99,5 (85,3)	98,9 (87,0)	97,0 (82,4)	99,2 (86,2)	99,5 (86,5)	94,2 (75,0)
FI	86,3 (64,9)	73,4 (38,4)	72,6 (43,7)	85,5 (62,2)	97,8 (70,4)	77,0 (47,2)	99,7 (79,4)	98,9 (81,3)	100,0 (96,0)	99,5 (85,3)	98,9 (86,7)	97,0 (81,9)	99,2 (86,1)	99,5 (86,4)	91,8 (72,1)
NO1	86,3 (64,7)	73,4 (38,4)	72,9 (43,7)	85,5 (61,8)	97,5 (69,7)	77,0 (47,0)	99,7 (79,3)	98,9 (81,3)	100,0 (96,0)	99,5 (85,2)	98,4 (86,7)	97,0 (81,9)	99,2 (86,1)	99,5 (86,3)	91,8 (72,0)
NO4	-	-	-	-	-	-	-	-	-	100,0 (100,0)	98,9 (86,7)	97,0 (81,9)	99,2 (86,0)	99,5 (86,2)	98,9 (88,2)
SE	86,3 (64,8)	73,4 (38,4)	72,6 (43,7)	85,5 (61,8)	97,8 (69,8)	97,0 (47,1)	99,7 (79,4)	98,9 (81,2)	100,0 (96,0)	99,5 (85,3)	98,9 (86,7)	98,1 (86,5)	-	-	90,6 (70,1)
SE1	-	-	-	-	-	-	-	-	-	-	-	-	99,2 (86,0)	99,5 (86,3)	99,3 (89,2)
SE2	-	-	-	-	-	-	-	-	-	-	-	-	99,2 (86,0)	99,5 (86,3)	99,3 (89,2)
SE3	-	-	-	-	-	-	-	-	-	-	-	-	99,2 (86,0)	99,5 (86,3)	99,3 (89,2)
SE4	-	-	-	-	-	-	-	-	-	-	-	-	99,2 (86,1)	99,5 (86,3)	99,3 (89,2)

[17] See Appendix, Table 11, Figure 10, and Figure 11
[18] The leading system price has, on average, increased 1,70 EUR/MWh/year from 2000.to 2013

Note: Values in brackets represent the percentage of decoupled prices in hours.

In more detail, we observe from Table 3 and Figure 2 that mean absolute and percentage differences between area and system prices are mainly pronounced in the Danish areas, Finland, and Sweden before splitting. Norway 1 is the only area with on average 3% lower price compared to the system price throughout the studied period. The spatial and temporal price variation, caused by local and regional electricity supply and demand conditions, clearly illustrates the need to hedge the locational price risk in the Nordic electricity market.

Table 3. Mean absolute and percentage () difference between area prices and system price, EUR/MWh

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
DK1	3,69 (0,31)	0,59 (0,02)	-1,44 (0,05)	-3,01 (-0,06)	-0,12*** (-0,01)	7,9 (0,26)	-4,41 (-0,08)	4,47 (0,2)	11,7 (0,31)	1,03 (0,02)	-6,57 (-0,09)	0,91 (0,17)	5,14 (0,25)	0,88** (0,01*)
DK2	-8,03 (-0,71)	0,4 (0,01)	1,67 (0,09)	0,11** (0*)	-0,57 (-0,03)	4,47 (0,13)	-0,06* (0*)	5,08 (0,24)	11,91 (0,3)	4,86 (0,12)	3,88 (0,03)	2,36 (0,2)	6,36 (0,29)	1,5 (0,03)
EE	-	-	-	-	-	-	-	-	-	-	-18,14 (-0,29)	-3,7 (0,12)	8 (0,44)	5,04 (0,15)
FI	2,14 (0,19)	-0,31 (-0,02)	0,36 (0,04)	-1,39 (-0,04)	-1,24 (-0,05)	1,19 (0,04)	-0,02* (-0,01)	2,08 (0,14)	6,29 (0,16)	1,96 (0,05)	3,58 (0,03)	2,25 (0,14)	5,44 (0,2)	3,05 (0,08)
NO1	-0,7 (-0,05)	-0,07 (0)	-0,34 (-0,02)	0,42 (0,01)	0,48 (0,02)	-0,21 (-0,01)	0,63 (0,02)	-2,19 (-0,11)	-5,57 (-0,13)	-1,27 (-0,03)	1,19 (0,04)	-0,63 (-0,03)	-1,64 (-0,05)	-0,54 (-0,01)
NO2	-0,24 (-0,03)	0,31 (0,02)	0,01* (0)	0,48 (0,01)	0,22 (0,02)	0,06*** (0)	0,38 (0,01)	1,66 (0,13)	6,45 (0,17)	0,53*** (Inf)	-1,22 (0*)	-0,96 (-0,03)	-2,04 (-0,05)	-0,77 (-0,02)
NO3	-8,55 (-0,74)	-16,72 (-0,74)	-23,8 (-0,96)	-17,21 (-0,54)	-17,16 (-0,59)	-	-44,33 (-0,88)	1,51 (0,12)	-0,71 (0,06)	-10,1 (Inf)	4,97 (0,06)	0,44 (0,02)	0,28* (0,01)	0,85 (0,02)
NO4	-	-	-23,8 (-0,96)	-18,57 (-0,59)	-	-	-	-	-	-	2,02 (0,02)	0,43 (0,04)	-0,03* (0)	0,5 (0,01)
NO5	-	-	-	-	-	-	-	-	-	-	-11,93 (-0,17)	-1,19 (-0,05)	-2,25 (-0,07)	-0,51 (-0,01)
SE	1,5 (0,12)	-0,29 (-0,02)	0,7 (0,04)	-0,2 (-0,01)	-0,84 (-0,03)	0,43 (0,01)	-0,47 (-0,01)	2,33 (0,15)	6,39 (0,16)	1,99 (0,05)	3,76 (0,03)	0,79 (0,03)	-	-
SE1	-	-	-	-	-	-	-	-	-	-	-	-0,06* (-0,01)	0,52 (0,02)	1,09 (0,03)
SE2	-	-	-	-	-	-	-	-	-	-	-	-0,06* (-0,01)	0,58 (0,02)	1,09 (0,03)
SE3	-	-	-	-	-	-	-	-	-	-	-	0,89 (0,01)	1,13 (0,03)	1,34 (0,03)
SE4	-	-	-	-	-	-	-	-	-	-	-	4,64 (0,1)	3,01 (0,1)	1,82 (0,04)

Note: ***, **, and * indicate *non-significance* at 1%, 5% and 10%, respectively. Values in brackets represent the percentage differences between area prices and system price.

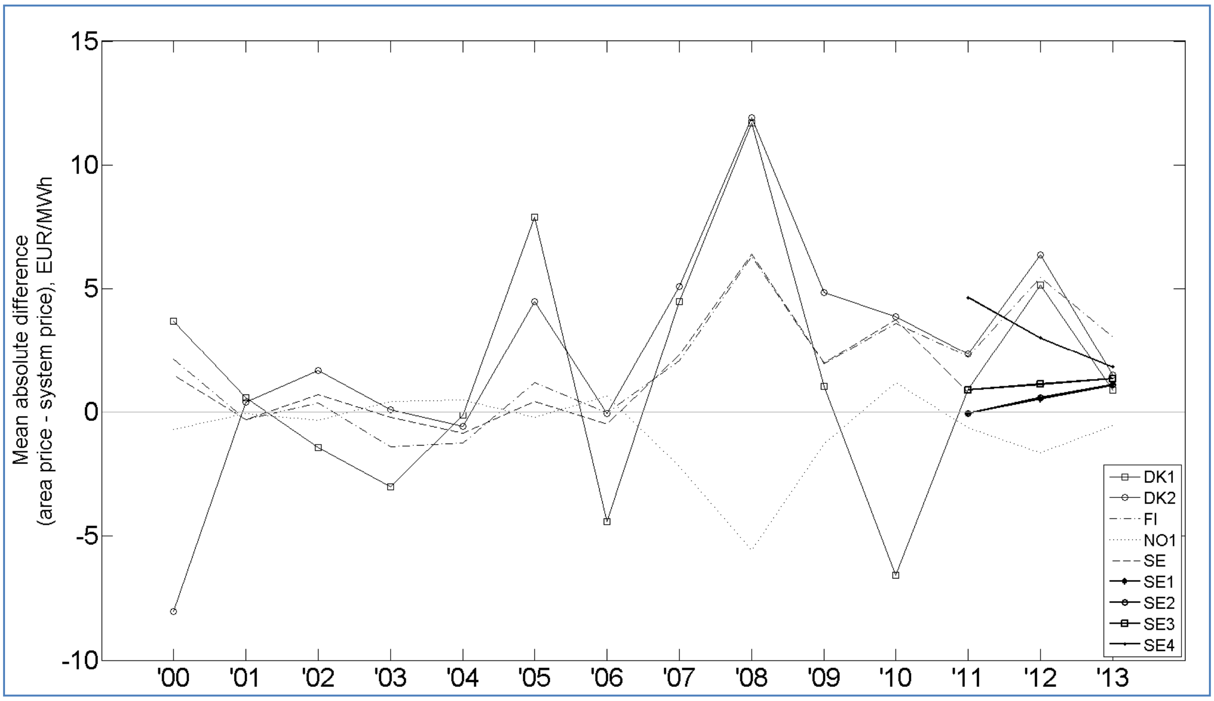

Figure 2 Mean absolute difference (area price – system price), EUR/MWh

Moving from physical (Elspot) to financial (Nasdaq OMXC) market, we assess mean EPAD closing prices according to the contracts' year of delivery/maturity and trading location (see Table 4). The signs, magnitude, and dispersion (standard deviation) across areas, years, and contract types point out to the dynamic nature of EPADs. For instance, Oslo (NO1) is the only area with mainly negative mean EPAD prices, which may be explained by large hedging pressure from hydro producers who demand a hedge against price spread especially in wet years. For other areas, EPAD prices are mostly positive, with the highest volatility in Denmark (DK1, DK2) and Finland. We would, *ex ante*, hold the expectations that areas with large amount of hydro reservoirs show less volatility in prices, thus the expected prices should also be less volatile in e.g. Sweden bidding areas 1-3, and Norway. Reversely, the expected EPAD prices should be higher in Finland, Swedish bidding area 4, Denmark and the Baltic States.

In more detail, we focus on EPAD monthly futures (MF) contracts, which substituted the seasonal contracts in 2004. We synchronize (Shawky, Marathe, & Barrett, 2003) the ends of trading periods for MF as well as the respective area price differences (DSPOT) during the delivery period. The summary statistics of the two price series are given in Appendix, Table 12. Infrequent price spikes cause the series to be leptokurtic, i.e. spiked, and with long right tails, i.e. positively skewed. This is mainly due to limits of economically storing electricity, supply and demand variations, as well as technical capabilities and conditions of the grid.

Both spot and futures prices are not significantly different from zero, and the volatility (std.dev.) of spot price differences is 2 to 6 times higher than volatility of the monthly futures series.

Table 4 Mean EPAD closing prices and their standard deviation, EUR/MWh

Area	Delivery period	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Århus (DK1)	Month	-	-	-	-	-	-	4,88 (2,99)	13,81 (7,49)	3,5 (1,9)	-1,53 (6,52)	0,1 (9,22)	7,86 (3,79)	0,36 (1,98)
	Quarter	-	-	-	-	-	4,44 (4,76)	2,43 (4,84)	8,02 (5,89)	7,29 (3,64)	2,9 (3,54)	1,24 (4,5)	6,45 (2,09)	3,02 (2,89)
	Season	0,69 (1,52)	0,82 (1,27)	-1,73 (4,51)	-0,01 (2,38)	3,72 (2,46)	-	-	-	-	-	-	-	-
	Year	-	0,51 (0,29)	0,38 (2,27)	-0,39 (0,5)	2,35 (0,6)	5,4 (1,52)	3,87 (3,33)	4,54 (0,52)	6,75 (2,52)	7,17 (2,44)	7,02 (3,82)	6,75 (2,02)	6,32 (0,85)
Copenhagen (DK2)	Month	-	-	-	0,45 (0,27)	3,62 (2,33)	4,39 (5,41)	5,07 (2,83)	13,6 (5,17)	5,47 (3,36)	2,79 (2,5)	4,09 (7,6)	9,7 (3,33)	1,88 (2,16)
	Quarter	-	-	-	-	-	6,75 (3,23)	4,42 (2,88)	8,78 (4,36)	8,63 (3,42)	4,71 (2,09)	3,78 (3,23)	9,02 (1,65)	5,03 (2,58)
	Season	0,26 (0,19)	1,61 (0,9)	0,85 (0,67)	0,93 (0,49)	2,49 (1,66)	-	-	-	-	-	-	-	-
	Year	-	0,79 (0,45)	1,48 (0,49)	0,99 (0,4)	1,37 (0,09)	5,15 (1,84)	6,25 (3,89)	5,2 (0,91)	7,64 (3,37)	7,85 (2,61)	8,09 (3,06)	7,81 (1,86)	7,74 (1,26)
Helsinki (FI)	Month	-	-	-	-0,4 (0,15)	1,02 (0,64)	0,67 (0,79)	1,49 (1,35)	5,81 (2,98)	1,98 (1,25)	1,21 (1,9)	3,57 (3,38)	7,32 (3,61)	3,47 (2,32)
	Quarter	-	-	-	-	-	0,98 (0,55)	0,76 (0,49)	2,57 (2,15)	2,33 (1,16)	1,27 (0,62)	2,2 (1,64)	5 (2,06)	5,05 (1,96)
	Season	0,54 (0,52)	0,57 (0,24)	0,39 (0,42)	0,03 (0,4)	0,52 (0,55)	-	-	-	-	-	-	-	-
	Year	-	0,44 (0,14)	0,71 (0,08)	0,32 (0,14)	0,23 (0,2)	1,03 (0,37)	0,73 (0,28)	0,89 (0,29)	1,45 (0,88)	1,19 (0,42)	1,45 (0,39)	1,91 (0,97)	3,11 (1,82)
Oslo (NO1)	Month	-	-	-	0,31 (0,06)	-0,19 (0,22)	0,67 (0,81)	-0,89 (1,52)	-4,47 (3,4)	-1,34 (0,91)	0,51 (1,24)	0,44 (2,89)	-1,73 (1,02)	-0,39 (1,23)
	Quarter	-	-	-	-	-	0,18 (0,56)	0,1 (0,98)	-1,86 (2,14)	-1,28 (0,6)	-0,27 (0,79)	0,5 (1,25)	-0,97 (1,03)	-1,02 (0,67)
	Season	-0,18 (0,21)	-0,12 (0,12)	0,28 (0,39)	0,27 (0,1)	-0,02 (0,31)	-	-	-	-	-	-	-	-
	Year	-	-0,04 (0,06)	-0,06 (0,23)	0,24 (0,07)	0,24 (0,07)	-0,13 (0,1)	0,43 (0,36)	-0,26 (0,51)	-0,35 (0,59)	-0,35 (0,44)	-0,25 (0,34)	-0,22 (0,38)	-0,33 (0,42)
*Stockholm (SE/SE3)	Month	-	-	-	0,06 (0,26)	0,78 (0,34)	0,62 (0,6)	1,08 (1,43)	5,56 (3,19)	2,1 (1,22)	1,14 (1,96)	3,53 (3,2)	2,92 (1,62)	1,27 (1,27)
	Quarter	-	-	-	-	-	0,71 (0,4)	0,49 (0,5)	2,19 (2,23)	2,13 (1,07)	1,07 (0,64)	1,96 (1,68)	2,98 (1,2)	2,02 (1,01)
	Season	0,33 (0,42)	0,42 (0,21)	0,44 (0,19)	0,39 (0,19)	0,56 (0,27)	-	-	-	-	-	-	-	-
	Year	-	0,28 (0,16)	0,52 (0,07)	0,47 (0,12)	0,35 (0,08)	0,74 (0,17)	0,44 (0,21)	0,46 (0,14)	0,93 (0,8)	0,67 (0,27)	0,9 (0,39)	1,44 (0,83)	1,93 (0,71)
Luleå (SE1)	Month	-	-	-	-	-	-	-	-	-	-	0,26 (0,44)	-0,04 (0,61)	0,17 (0,6)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0,21 (0,28)	0,16 (0,29)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0,45 (0,3)	-0,29 (0,44)
Malmö (SE4)	Month	-	-	-	-	-	-	-	-	-	-	13,02 (2,28)	6,56 (2,28)	2,17 (1,63)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	8,04 (1,69)	4,57 (1,96)
	Year	-	-	-	-	-	-	-	-	-	-	-	7,64 (1,74)	7,04 (1,61)
Sundsvall (SE2)	Month	-	-	-	-	-	-	-	-	-	-	1,04 (0,45)	-0,01 (0,64)	0,22 (0,7)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	0,02 (0,36)	0,17 (0,3)
	Year	-	-	-	-	-	-	-	-	-	-	-	0,03 (0,29)	-0,22 (0,48)
*Tromsø (NO3/NO4)	Month	-	-	-	-	-	-	-	-	-	-	-0,11 (0,34)	-0,47 (0,31)	-0,12 (0,36)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0,31 (0,22)	-0,32 (0,17)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0,04 (0,3)	-0,25 (0,3)

Note: All values are given in EUR/MWh; *Tromsø was NO3 before 10.1.2010 and NO4 thereafter; *SE/SE3 combines data for Sweden before the split (SE) into four areas in Nov.2011 and the Stockholm area (SE3) thereafter.

Last, due to our research approach, i.e. VAR estimation, we test whether the time-series of monthly futures (MF) prices and the corresponding area spot price differences (DSPOT) during the delivery period, are stationary. We reject the presence of individual unit roots for all variables at 1% significance level by Phillips-Perron test and at 10% significance level by Augmented Dickey-Fuller test for all but Sundsvall monthly futures (SE2_MF). We conclude that all time-series are stationary, which is in contrast to some studies (De Vany & Walls, 1999; Bunn & Gianfreda, 2010) but at the same time in agreement with others (Dempster, Isaacs, & Smith, 2008; Worthington, Kay-Spratley, & Higgs, 2005). Unit root statistics are tested on sub-samples in respect to times when individual areas have joined the Nordic market and when the respective monthly contracts started to be traded. See the summary and note in Table 5.

Table 5 Unit root test statistics - Intermediate Phillips-Perron and ADF test results

Series	Phillips-Perron.	Bandwidth (PP)	ADF	Lag (ADF)	Obs (ADF)
DK2_DSPOT	0.0001	31.0	0.0000	4	2461
DK2_MF	0.0025	32.0	0.0008	0	2333
FI_DSPOT	0.0001	29.0	0.0000	11	2461
FI_MF	0.0010	2.0	0.0009	2	2345
*SE3_DSPOT	0.0001	29.0	0.0000	11	2461
*SE3_MF	0.0001	4.0	0.0002	2	2319
NO1_DSPOT	0.0000	18.0	0.0000	12	2461
NO1_MF	0.0008	20.0	0.0020	2	2411
DK1_DSPOT	0.0000	26.0	0.0000	6	1656
DK1_MF	0.0155	25.0	0.0030	2	1513
SE1_DSPOT	0.0000	9.0	0.0000	1	564
SE1_MF	0.0915	5.0	0.0328	0	420
SE2_DSPOT	0.0000	9.0	0.0000	1	564
SE2_MF	0.6390	6.0	0.3060	0	419
SE4_DSPOT	0.0000	8.0	0.0000	2	564
SE4_MF	0.0552	6.0	0.0810	0	430
NO3_DSPOT	0.0000	14.0	0.0000	6	564
NO3_MF	0.0005	5.0	0.0080	2	434

Note: *SE3 refers to Sweden before the area splitting (Nov.2011) and to Stockholm thereafter.

5 Open interest and risk premia in EPADs

The open interest, defined as a number of open contracts which have not yet been liquidated, is an adequate proxy to liquidity worthwhile close assessment. Figure 3 presents the development of the EPAD trade over 2000-13, in terms of GWh and with the break-down by price area, while Figure 4 shows the development in terms of number of contracts and with the break-down by contract type. The price areas with the largest open interest in EPAD are 'SE3 Stockholm' and 'FI Helsinki', with the *volume* shares 46% and 33% respectively (as of

2013). Quarterly contracts are somewhat more popular than the monthly or the yearly contracts, their shares in the *number* of contracts are 41%, 32% and 27% respectively (as of 2013 as well).

The open interest for EPAD contracts expanded between 2006-13 from 8 GWh up to 28 GWh. The expansion is most likely due to product restructuring and the change of the trading currency in 2006.[19] The three seasonal contracts of unequal length[20] were replaced with standardised quarterly and monthly contract while the yearly contracts have been preserved. The currency of trading was changed from Norwegian Krone to Euro for products with the delivery date January 1st, 2006 and beyond.

The total open interest on the Nordic financial electricity market exceeded 300,000 GWh in 2009 (NordREG, 2010, p. 25), i.e. EPADs constitute a negligible fraction of the market. The EPAD contracts offer hedging against the price difference between the system price and the area price which requires estimate of, or modelling, the two prices. Separate forward contracts do not require understanding of both the system-wide and local price dynamics and thus appear more flexible. A financial market player might prefer to trade system forwards only. A local generator or a consumer sells or buys power at the area price and may prefer to purchase area forwards.

[19] While the trade growth of the main Nordic market might also explain the EPAD expansion (the trade volume nearly doubled between 2006 and 2012), it is not clear whether the trade, in fact, intensified after the product/currency changes on the financial market.

[20] Contract 'Winter 1' covered four months January-April; contract 'Summer' covered five month May-September, and contract 'Winter 2' covered three months October-December.

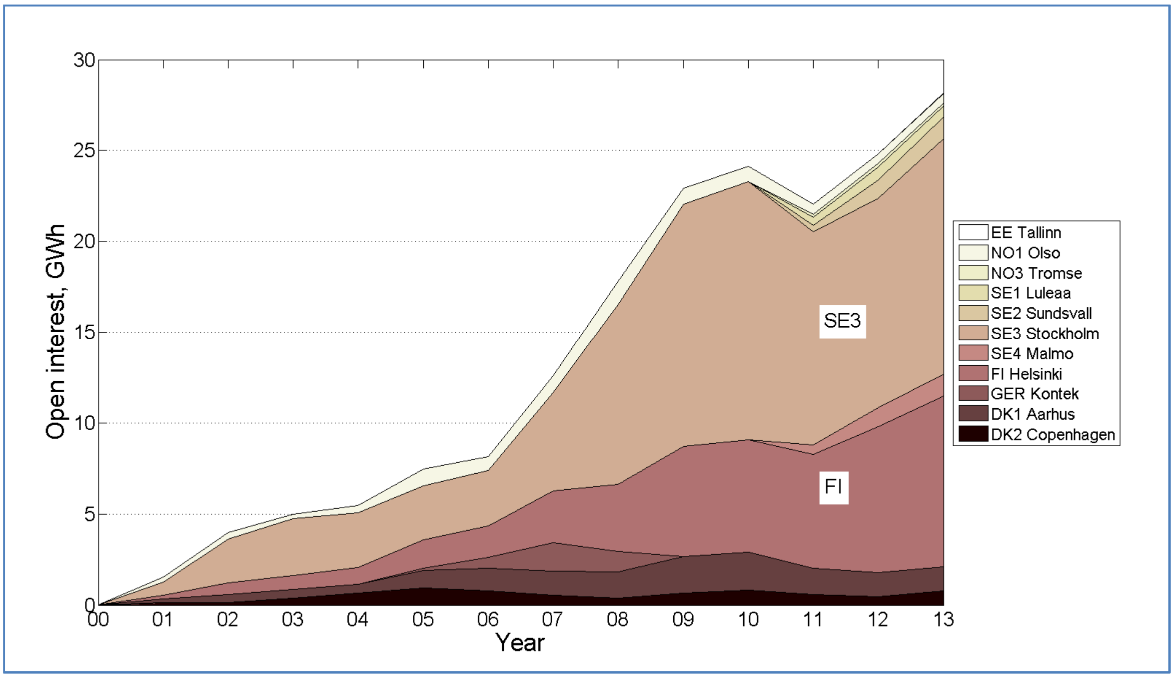

Figure 3. Development of the open interest of EPADs, GWh, break-down by price area.

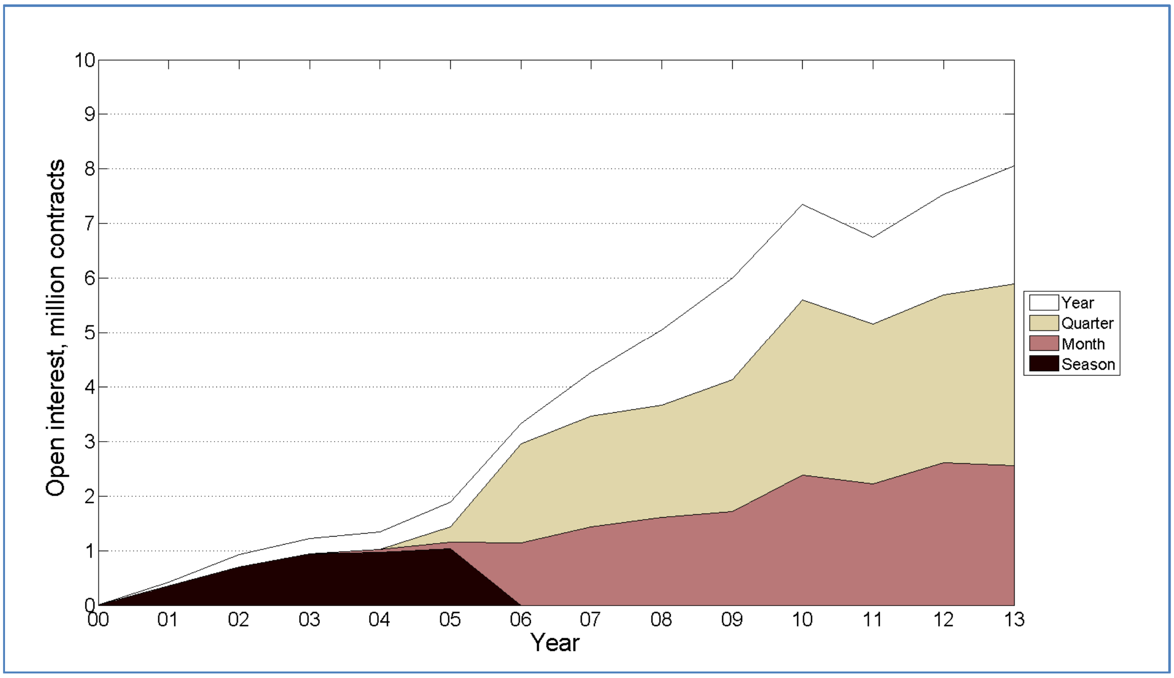

Figure 4. Development of the open interest of EPADs, number of contracts, break-down by contract type.

Next, we examine the risk premia in all traded EPAD products with delivery between 2000 and 2013, calculated according to the formulas in Section 3 (formula 3). Table 6 demonstrates that EPAD contracts contain considerable risk premia which vary in sign and magnitude across contract types, areas, and years. On the one hand, the areas with highest risk premia volatility (standard deviation) are Aarhus (DK1) and Copenhagen (DK2) for quarterly and monthly contracts, especially in 2008, 2010 and 2011. In general, the highest volatility is observed in the most popular contracts (% of total number of contracts), quarterly and monthly, which includes more frequent extreme values dispersing the distribution from mean risk premia. Denmark is also country with the highest (positive) mean risk premia, especially Aarhus where, for instance, yearly 2010 EPAD contract contained risk premia of 13,74 EUR/MWh. The specificity of Aarhus DK1 area is that it contains approximately three times as much installed wind power capacity as Copenhagen, which increases the price volatility and the hedging need of retailers and large customers. On the other hand, the contracts with often negative risk premia are yearly contracts, especially observable in Helsinki and Oslo areas.

Poor (good) hydro year, measured by the deviation of the current percentage value from the historic median, tends to increase (decrease) the Nordic system price[21] (see Appendix, Table 11). Drier years were 2002-03, 2006-07, or 2010-11, while years with higher precipitation were 2007-08, 2011-12. During drier time periods hydro producers reduce output to save the scarcer energy source and more plants with higher marginal cost are operating. Areas with large share of hydro production cannot transmit all demanded lower marginal cost electricity to areas based more on thermal units (higher marginal cost) due to limited capacity of cross-border transmission. This leads to higher hedging pressure from retailers and bigger customers willing to pay a premium (positive risk premia) for the expected increase in local area price compared to system price. This holds generally true for Stockholm area and Helsinki, but Oslo area is slightly different. Oslo has on average lower area price than the system price, and it seems the hydro level deviation tends to impact more strongly the system price than the area price in Oslo. So the producers keep selling EPADs even during the dry years, i.e. expecting the area price will be still lower than the system price.

Table 6 Ex-post risk premia of EPADs - means and standard deviations

	Delivery period	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Århus (DK1)	Month	-	-	-	-	-	-	-1,94 (4,97)	2,23 (6,99)	2,44 (2,92)	5,11 (9,41)	-0,91 (6,53)	2,86 (4,1)	-0,54 (5,92)
	Quarter	-	-	-	-	-	9,05 (6,41)	-2,02 (3,52)	-3,63 (9,75)	6,28 (3,6)	9,54 (7,74)	0,4 (7,82)	1,34 (4,52)	2,08 (2,74)
	Winter 1	2,46 (0,2)	-1,32 (0,25)	6,2 (7,32)	-1,16 (1,33)	-0,45 (0,93)	-	-	-	-	-	-	-	-
	Summer	0,72 (1,81)	-1,5 (0,78)	-2,33 (1,27)	1,23 (0,8)	-5,5 (1,33)	-	-	-	-	-	-	-	-
	Winter 2	-1,39 (0,52)	14,25 (0,24)	1,72 (1,06)	1,12 (0,48)	-5,58 (1,32)	-	-	-	-	-	-	-	-
	Year	-	1,95 (0,29)	3,38 (2,27)	-0,27 (0,5)	-5,55 (0,6)	9,81 (1,52)	-0,6 (3,33)	-7,16 (0,52)	5,72 (2,52)	13,74 (2,44)	6,11 (3,82)	1,62 (2,02)	5,44 (0,85)

[21] See also (Bühler & Müller-Mehrbach, 2009)

Copenhagen (DK2)	Month	-	-	-	1,05 (1,05)	-0,92 (5,53)	4,45 (4,23)	0,01 (3,47)	1,72 (7,11)	0,47 (5,55)	-1,13 (6,6)	1,63 (8,81)	3,46 (4,96)	1,95 (2,56)
	Quarter	-	-	-	-	-	6,84 (6,01)	-0,63 (4,24)	-3,14 (8,22)	3,81 (5,85)	0,84 (5,28)	1,49 (8,9)	2,69 (5,7)	3,65 (4,14)
	Winter 1	-	-1,38 (0,52)	1,9 (0,69)	1,36 (0,24)	-2,14 (0,14)	-	-	-	-	-	-	-	-
	Summer	0,77 (0,17)	-0,59 (0,77)	-0,07 (0,8)	1,94 (0,52)	2,08 (1,37)	-	-	-	-	-	-	-	-
	Winter 2	-1,22 (0,19)	2,72 (0,26)	0,72 (0,48)	1,36 (0,19)	-8,38 (1,27)	-	-	-	-	-	-	-	-
	Year	-	-0,89 (0,45)	1,37 (0,49)	1,56 (0,4)	-3,1 (0,09)	5,21 (1,84)	1,16 (3,89)	-6,71 (0,91)	2,78 (3,37)	3,97 (2,61)	5,73 (3,06)	1,45 (1,86)	6,24 (1,26)
Helsinki (FI)	Month	-	-	-	0,79 (0,58)	-0,18 (1,11)	0,67 (1,86)	-0,6 (3,37)	-0,45 (4,66)	-0,08 (3,34)	-2,41 (7,3)	1,28 (4,66)	1,76 (3,5)	0,74 (3,56)
	Quarter	-	-	-	-	-	0,96 (1,67)	-1,28 (3,19)	-3,69 (5)	0,4 (2,69)	-2,31 (5,17)	0 (3,84)	-0,41 (2,69)	2,08 (3,24)
	Winter 1	1,39 (0,07)	0,23 (0,18)	2,32 (0,48)	1,55 (0,39)	-0,54 (0,11)	-	-	-	-	-	-	-	-
	Summer	1,69 (0,62)	-1,34 (0,24)	1,12 (0,51)	1,5 (0,31)	-0,27 (0,61)	-	-	-	-	-	-	-	-
	Winter 2	-0,1 (0,19)	2,81 (0,1)	2,21 (0,13)	0,78 (0,36)	-1,34 (0,32)	-	-	-	-	-	-	-	-
	Year	-	0,08 (0,14)	2,1 (0,08)	1,56 (0,14)	-0,97 (0,2)	1,05 (0,37)	-1,35 (0,28)	-5,4 (0,29)	-0,51 (0,88)	-2,39 (0,42)	-0,81 (0,39)	-3,52 (0,97)	0,05 (1,82)
Oslo (NO1)	Month	-	-	-	-0,16 (0,5)	0,02 (0,28)	0,05 (1,24)	1,32 (3,19)	1,06 (4,35)	-0,02 (2)	-0,7 (3,48)	1,09 (2,81)	-0,05 (1,77)	-0,67 (1,83)
	Quarter	-	-	-	-	-	-0,43 (0,84)	2,25 (3,17)	3,7 (5,2)	-0,03 (1,35)	-1,48 (1,85)	1,1 (2,24)	0,66 (1,44)	-0,58 (1,35)
	Winter 1	-0,54 (0,06)	0,05 (0,06)	-0,89 (0,47)	-0,22 (0,13)	0,62 (0,07)	-	-	-	-	-	-	-	-
	Summer	-0,27 (0,23)	0,71 (0,16)	0,56 (0,35)	-0,34 (0,06)	0,03 (0,38)	-	-	-	-	-	-	-	-
	Winter 2	0,21 (0,1)	-0,39 (0,08)	-0,25 (0,16)	-0,02 (0,07)	-0,1 (0,14)	-	-	-	-	-	-	-	-
	Year	-	0,3 (0,06)	-0,48 (0,23)	-0,24 (0,07)	0,45 (0,07)	-0,76 (0,1)	2,62 (0,36)	5,31 (0,51)	0,92 (0,59)	-1,54 (0,44)	0,38 (0,34)	1,42 (0,38)	0,21 (0,42)
*Stockholm (SE/SE3)	Month	-	-	-	0,96 (0,72)	0,36 (0,5)	1,08 (1,44)	-1,26 (3,21)	-0,81 (4,63)	0,01 (3,31)	-2,68 (7,14)	2,71 (2,93)	1,78 (1,86)	0,47 (2,42)
	Quarter	-	-	-	-	-	1,14 (0,84)	-1,8 (3,04)	-4,17 (5,01)	0,17 (2,51)	-2,7 (5,7)	1,17 (1,94)	1,86 (1,62)	0,77 (2,44)
	Winter 1	1,11 (0,1)	0,15 (0,25)	1,53 (0,1)	1,28 (0,15)	-0,2 (0,08)	-	-	-	-	-	-	-	-
	Summer	1,33 (0,5)	-1,28 (0,15)	-0,2 (0,26)	1,23 (0,24)	0,35 (0,29)	-	-	-	-	-	-	-	-
	Winter 2	-0,22 (0,15)	0,76 (0,11)	0,9 (0,14)	1,23 (0,11)	0,18 (0,21)	-	-	-	-	-	-	-	-
	Year	-	-0,42 (0,16)	0,73 (0,07)	1,31 (0,12)	-0,08 (0,08)	1,22 (0,17)	-1,88 (0,21)	-5,92 (0,14)	-1,06 (0,8)	-3,09 (0,27)	0,1 (0,39)	0,31 (0,83)	0,58 (0,71)
Luleå (SE1)	Month	-	-	-	-	-	-	-	-	-	-	0,32 (0,8)	-0,59 (1,46)	-0,34 (2,21)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0,72 (0,96)	-0,83 (1,76)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0,98 (0,3)	-1,37 (0,44)
Sundsvall (SE2)	Month	-	-	-	-	-	-	-	-	-	-	1,1 (0,78)	-0,62 (1,45)	-0,33 (2,22)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0,55 (1,02)	-0,82 (1,75)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0,55 (0,29)	-1,31 (0,48)
Malmö (SE4)	Month	-	-	-	-	-	-	-	-	-	-	8,4 (3,04)	3,6 (3,66)	1,31 (2,83)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	5,02 (2,95)	2,91 (3,3)
	Year	-	-	-	-	-	-	-	-	-	-	-	4,63 (1,74)	5,22 (1,61)
*Tromsø (NO3/NO4)	Month	-	-	-	-	-	-	-	-	-	-	1,2 (1,02)	-0,46 (0,94)	0,05 (0,74)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0,28 (0,62)	-0,71 (0,69)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0,01 (0,3)	-0,74 (0,3)

Note: All values are given in EUR/MWh; *Tromsø was NO3 before 10.1.2010 and NO4 thereafter; *SE/SE3 combines data for Sweden before the split (SE) into four areas in Nov.2011 and the Stockholm area (SE3) thereafter.

6 Determinants of risk premia in EPADs

The following section sheds more light on the role of hydro reservoirs in explaining the locational price spreads, i.e. area prices minus the system price, which are the building blocks of EPADs in the Nordic electricity market. Further, we evaluate the role of time-to-maturity and risk premia, and test their hypothesized negative relationship.

6.1 Role of Hydro

In line with Marckhoff and Wimschulte (2009), referred to in this section as MW2009 for brevity,, we examine the relationship between the hydropower capacity and the area-system price differential. The hydro reservoir capacity of the country is measured in per cent to the maximum GW capacity but it is the deviation of the current percentage value from the historic median that matters. Figures 5-7 plot the current and historic median percentage values of the hydro capacity, respectively for Norway, Sweden and Finland. The median levels are computed based on Nord Pool data that begins from 1995 for all three countries.

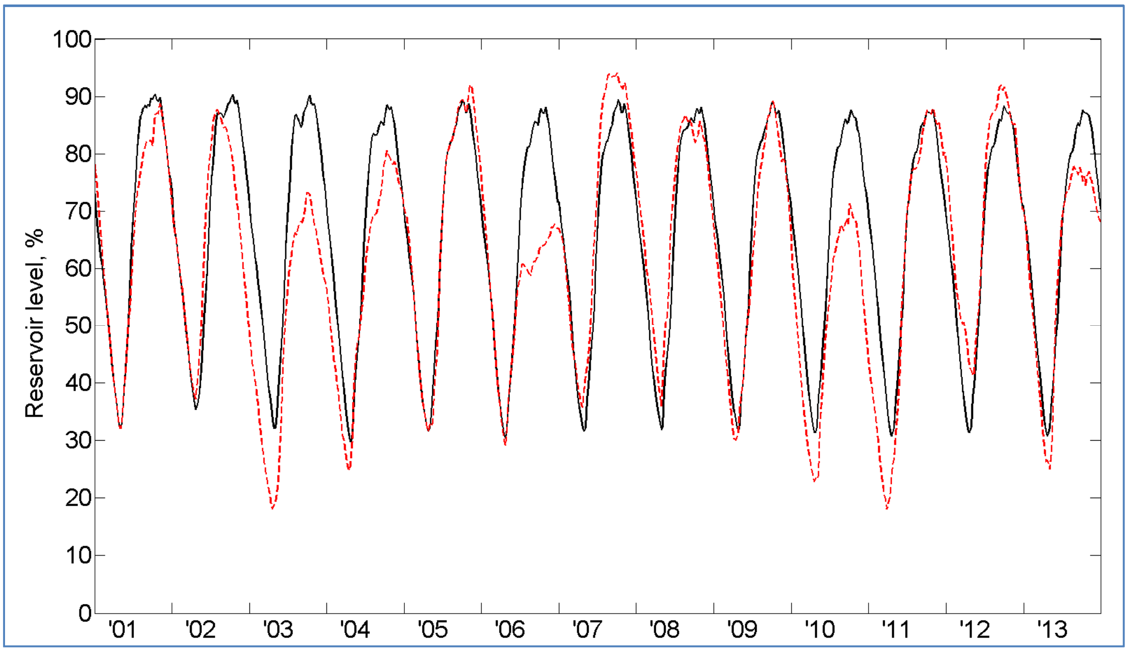

Figure 5. Reservoir level, Norway, historic median (solid line) and current level (dashed line).

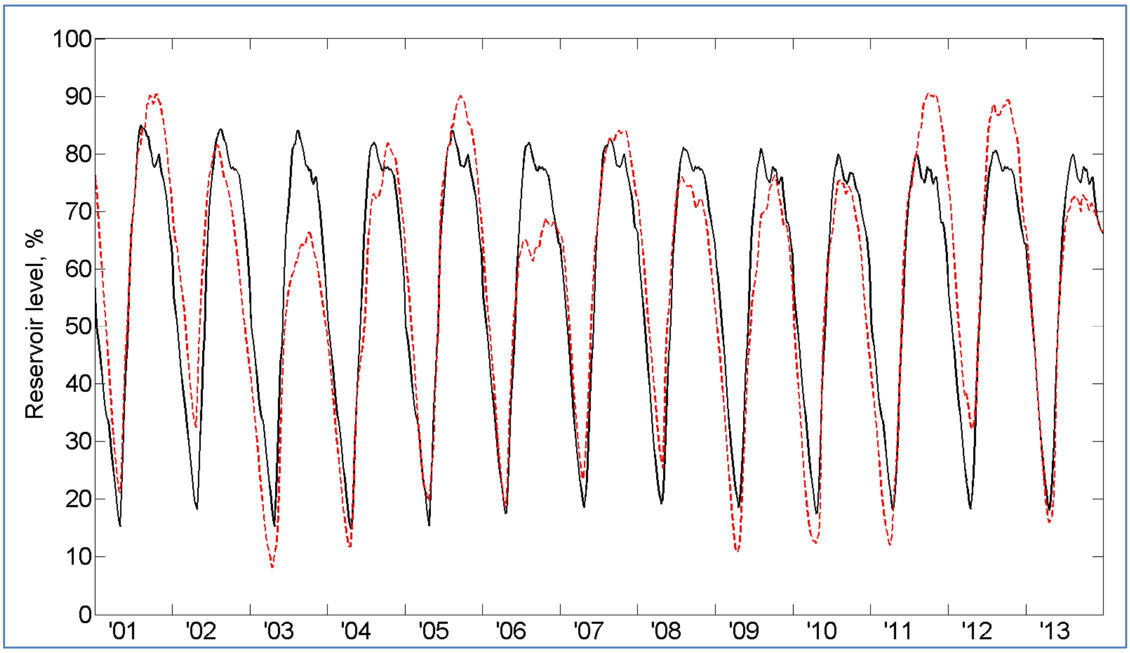

Figure 6. Reservoir level, Sweden, historic median (solid line) and current level (dashed line).

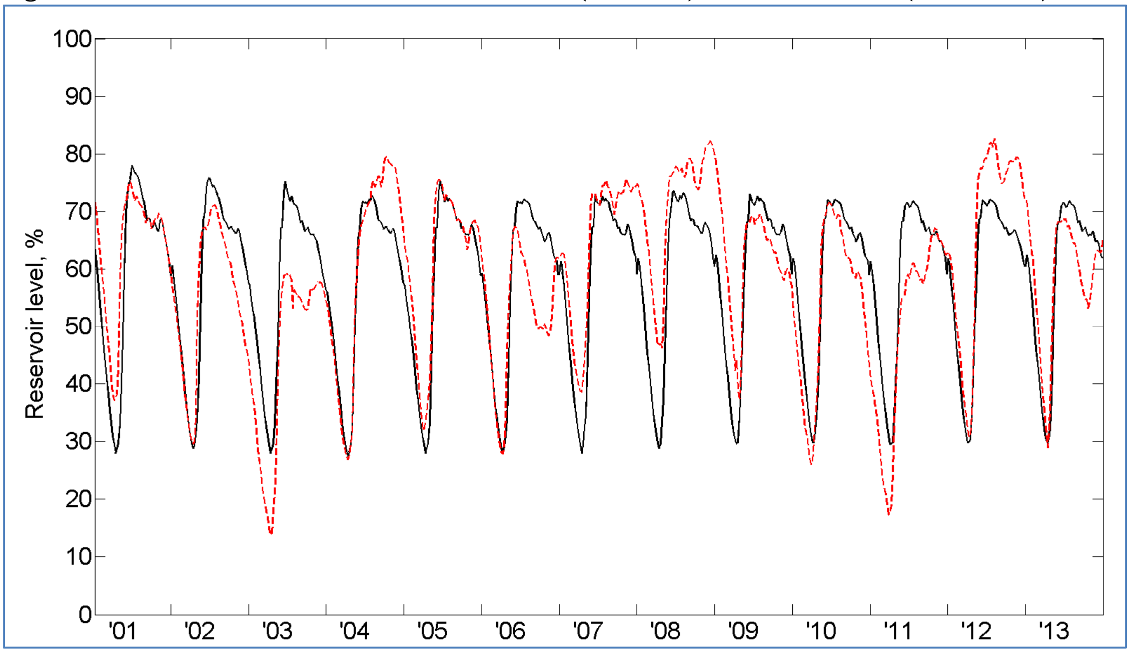

Figure 7. Reservoir level, Finland, historic median (solid line) and current level (dashed line).

Given that Sweden was split in four zones from November 1, 2011, we run an extended version of the MW2009 regression, with a structural break dummy:

$$\bar{S}_t^{Area} - \bar{S}_t^{System} = c + \beta^{No} RL_t^{No} + \mathbf{1}_{[t>01-11-2011]} \beta_S^{No} RL_t^{No} \qquad (4)$$

$$+\beta^{Fi} RL_t^{Fi} + \mathbf{1}_{[t>01-11-2011]} \beta_S^{Fi} RL_t^{Fi} + \beta^{Se} RL_t^{Se} + \mathbf{1}_{[t>01-11-2011]} \beta_S^{Se} RL_t^{Se} + \varepsilon_t,$$

where $\bar{S}_t^{Area}$ and $\bar{S}_t^{System}$ – weekly average area/system price;

RL_t – deviation of the current reservoir level from the historic median,

for Norway (No), Finland (Fi) and Sweden (Se);

$\mathbf{1}_{[t>01-11-2011]}$ – structural break dummy that equals one after November 1, 2011;

c – constant;

ε_t – error term.

We perform the regression for both Denmark areas, DK1 'Aarhus' and DK2 'Copenhagen', for the Norway area NO1 'Oslo', and for the Finland area 'Helsinki'. We combine the Sweden national price before the splitting and the Stockholm area price after the splitting to obtain the Swedish area price for the whole period, thus we cannot include the structural break dummy in the Swedish regression. The results are presented in Table 7.

Table 7. Regression of the area price spread and relative reservoir level (2001-2013).

	N	c	β^{No}	$\mathbf{1} * \beta_S^{No}$	β^{Fi}	$\mathbf{1} * \beta_S^{Fi}$	β^{Se}	$\mathbf{1} * \beta_S^{Se}$	Prob. (F-stat)	Adj. R^2
Aarhus (DK1)	679	4.19***	63.97**	21.16	0.81	0.74	-2.04	-42.33**	0.00	0.34
Copenhagen (DK2)	679	5.41***	54.72***	-12.70	-9.41**	-1.04	-16.88*	2.49	0.00	0.17
Oslo (NO1)	679	-1.63***	-21.49***	8.08	1.65	4.37	7.10**	-0.78	0.00	0.20
Helsinki (FI)	679	3.03***	33.77***	-19.36	-12.65***	7.17	-11.94**	13.31	0.00	0.11
Stockholm (SE3)	679	2.27***	25.98***	--	-7.54***	--	-17.49***	--	0.00	0.07

Note: The regression results are obtained using the Newey/West estimator. ***, **, * means statistical significance at 1%, 5%, 10% respectively.

The structural break dummy turns out to be insignificant for any price spread and any reservoir level, save the Aarhus area price spread and the Swedish hydropower. The Finnish hydro is not statistically significant in the Aarhus and Oslo regressions (same as in MW2009) but is significant in the Copenhagen regression (unlike the MW2009).

When compared to a shorter sample in MW2009 for years 2001-6, all the coefficients in our regression, with or without the structural break dummy, appear larger in terms of magnitude. A larger constant implies a larger price spread on average while larger coefficients imply a stronger response of the price spread to deviations of the hydro level from the median. Our finding provides indirect evidence of higher price variation on the Elspot market; yet examining the roots of such variation is beyond the scope of our paper and so can provide a basis for future research.[22]

6.2 Role of time-to-maturity

Prior research of electricity futures illustrates that risk premia are a negative function of *time-to-maturity*[23]. MW2009 illustrate and confirm this relationship for the period 2001-2006. We use their notation (p. 265.) and regress risk premia of CfDs π_t^{CfD} on their respective remaining time-to-maturity[24] τ_t during 2000 - 2013.

$$\pi_t^{CfD} = c + \beta\tau_t + \epsilon_t \qquad (5)$$

Where π_t = risk premium at time t

τ_t = remaining time-to-maturity

c = constant

ε_t = error term

The regression results are reported in Table 8, which are broadly similar to those in MW2009. Most equations have a significant and positive constant, in other words, the average risk premium at the expiration date is above zero and statistically significant. However, many equations have an insignificant coefficient on time-to-maturity (at least, one equation for each price area except SE3 Stockholm). The explanatory power of regression as measured by the adjusted R^2 varies considerably, and can be high or low irrespective of the significance level of the constant or the beta coefficient.

Consistent results (significant constant and beta, as well as R^2 above 0.1) are to be found for the following contracts: Aarhus/year, Copenhagen/season and year, Helsinki/year, Luleå / month, quarter and year, Malmö/month, Olso/season and quarter, SE3/month, quarter and year, Sundsvall/month and year, Tallinn/year, and finally Tromsø /quarter. The year contracts seem to have the ‘best’ fit, probably due to the long tradable period and hence a sufficient number of observations.

[22] The results also reveal the intricacies of trade between the areas as Denmark is heavily influenced by the Norwegian and Swedish reservoirs. Further investigations should be made into the area of price formation in the different bidding areas more explicitly accounting for the role of trade.
[23] See also studies by Diko et al. (2006); Benth et al. (2008)
[24] Time-to-maturity is calculated as the difference in calendar days between the trading day *t* and the first day of the delivery period for the respective contract

Open interest, and hence liquidity, do not seem to affect the relationship between risk premium and the time-to-maturity. Many contracts have large open interest but the regression result is inconclusive, and vice versa, a small volume of open interest may correspond to a contract with statistically significant relationship between risk premium and time-to-maturity.

Table 8. Regression results of the risk premium on time-to-maturity.

Area	Contract	N	c	beta	Adj. R^2
Aarhus (DK1)	Season	278	-0.2080	0.0061***	.0819
	Month	67	1.9482***	-0.0159	.0053
	Quarter	284	2.4278***	0.0035**	.0318
	Year	1081	2.2301***	0.0058***	.4998
Copenhagen (DK2)	Season	278	0.4115***	-0.0055***	.115
	Month	67	1.1235***	0.0046	-.0015
	Quarter	284	2.0321***	-0.0011	.0106
	Year	1081	1.5524***	0.0031***	.3762
Germany (Kontek)	Season	--	--	--	--
	Month	66	4.6741***	-0.0147	.0003
	Quarter	289	2.9147***	0.0051*	.0143
	Year	357	2.9386***	0.0065**	.013
Helsinki (FI)	Season	278	0.6231***	0.0011***	.0409
	Month	122	0.5079***	-0.0089***	.0985
	Quarter	301	-0.2730**	-0.001	.0075
	Year	1081	-0.2450***	-0.0024***	.7264
Luleå (SE1)	Season	--	--	--	--
	Month	122	0.2747**	-0.0153***	.3208
	Quarter	297	-0.4107***	-0.0018***	.1268
	Year	649	-0.6955***	-0.0016***	.6591
Malmö (SE4)	Season	--	--	--	--
	Month	122	4.1541***	-0.0327***	.443
	Quarter	299	3.7564***	0.0020**	.023
	Year	649	5.1647***	-0.0002	-.0002
Oslo (NO1)	Season	278	0.0286**	-0.0005***	.1677
	Month	67	0.1567	0.0035	-.0006
	Quarter	284	0.3056***	0.0025***	.1822
	Year	1081	0.7380***	-0.0005***	.0984
Stockholm (SE/SE3)	Season	278	0.4848***	0.0003*	.0191
	Month	122	0.7610***	-0.0138***	.2977
	Quarter	301	-0.0182	-0.0028***	.1423
	Year	1081	-0.3582***	-0.0008***	.16
Sundsvall (SE2)	Season	--	--	--	--
	Month	122	0.3492**	-0.0160***	.3332
	Quarter	297	-0.3661***	-0.0015***	.0933
	Year	649	-0.4009***	-0.0020***	.6185

Tallinn (EE)	Season	--	--	--	--
	Month	65	0.417	-0.0686	.0865
	Quarter	210	-3.1984***	0.0039*	.0321
	Year	20	0.4481	-0.0444***	.4415
Tromsø (NO3/NO4)	Season	--	--	--	--
	Month	67	-0.0134	-0.0052	.0634
	Quarter	279	-0.2908***	-0.0012***	.1552
	Year	649	-0.5756***	0.0002***	.0148

Note: N is the number of days to maturity. ***, **, * indicates significance at 1%, 5% and 10% level respectively. Regression results are obtained using the Newey/West estimator for the covariance matrix.

Figure 8 plots the relationship between the risk premium and time-to-maturity for year contracts, for DK2 Copenhagen, FI Helsinki and SE3 Stockholm only (to avoid cluttering the graph). The risk premium for Copenhagen contract has a declining trend but remains positive up until expiration (the beta coefficient is insignificant). The risk premia for Helsinki and Stockholm monthly EPAD contracts are also positive but, in contrast to the Copenhagen contracts, they both have an increasing trend (the beta coefficients are negative), with the Stockholm risk premium having a slightly steeper trend (the Stockholm beta coefficient is larger in absolute value).

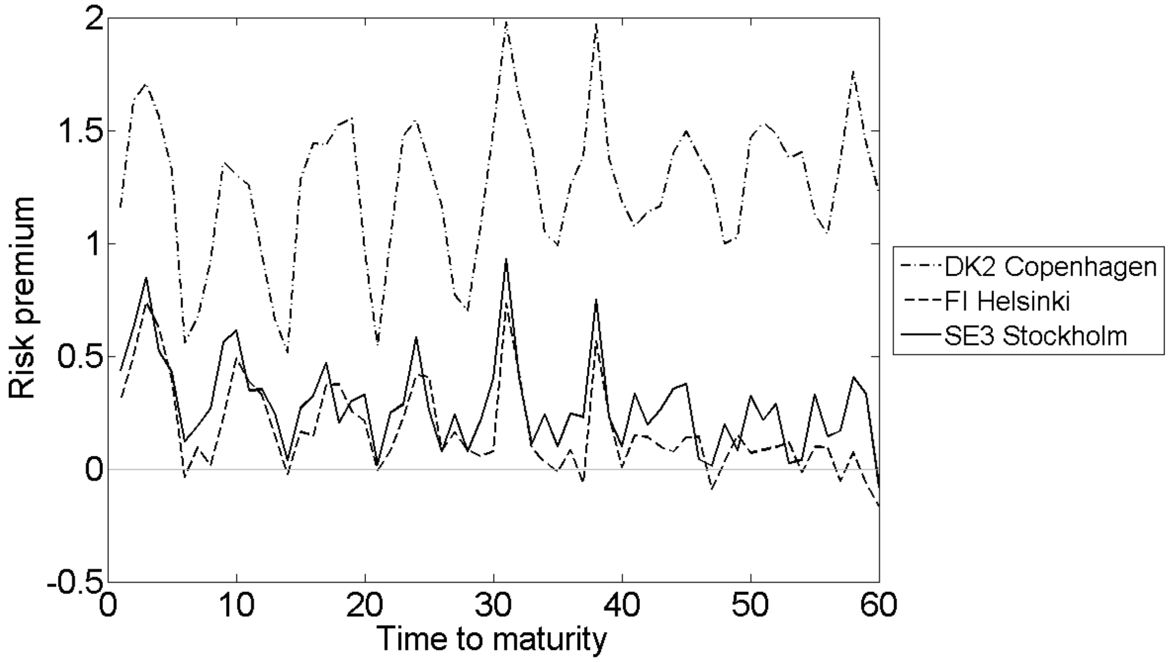

Figure 8. Risk premium and time-to-maturity, monthly EPAD contracts for price areas DK2 Copenhagen (top dash-dot line), FI Helsinki (bottom dashed line) and SE3 Stockholm (bottom solid line)
Note: The time-to-maturity is cut-off at 60 days for better representation, the full sample has 67 days for DK2, and 122 days for FI and SE3

7 Efficiency of EPADs - vector autoregression (VAR) model

We perform a confirmatory VAR model by which we seek to test theory of efficient pricing signals by investigating the relationship between monthly futures EPAD prices and the corresponding area spot price differences (area price – reference system price) during the contracts' delivery period. We focus on monthly EPAD contracts for two main reasons. First, monthly EPADs provide the highest price variability by being effectively EPADs with the shortest-term delivery period. This fact is also related to, on average, lower forecasting errors of market participants due to the near-term delivery period (Redl & Bunn, 2013). Second, monthly EPADs belong to the most liquid contract types, what generally implies higher efficiency in transaction costs, price discovery process, and speed of adjustment to fundamental information.

We take the convergence and relationship between spot and forward markets as a measure of efficiency. In an efficient spot and futures markets, we expect to see a bi-directional Granger causality between prices that send proper signals to each other. This means that the area spot price difference, reflecting the local cost of congestion, is properly reflected in the futures EPAD price, which is the expected cost of congestion. Vice versa, the expected cost of congestion priced in the EPAD is properly reflected in the realized spot price difference. These assumptions are tested by Granger causality tests and complemented by impulse response functions and variance decomposition. The latter two approaches allow for dynamic investigation of short-term transmission of shocks in the estimated relationships.

The linear interdependency between futures monthly EPAD prices and their area spot price references is captured by the following vector autoregressive model:

$$x_t = c_1 + \sum_{i=1}^{k} \varphi_{1i} x_{t-i} + \sum_{i=1}^{k} \psi_{1i} y_{t-i} + \mu_{1t}$$
$$y_t = c_2 + \sum_{i=1}^{k} \varphi_{2i} x_{t-i} + \sum_{i=1}^{k} \psi_{2i} y_{t-i} + \mu_{2t} \qquad (6)$$

Where x_t = *spot price S; daily average difference of area price and reference system price during the delivery period*

y_t = *futures price F; daily synthetic closing prices of monthly EPAD for a specific area*

φ = *Coefficient of lagged spot prices S*

ψ = *Coefficient of lagged futures prices F*

c_i = *constant*

μ_i = *i.i.d. error terms,* $\in \sim N_m(0, \Sigma_\epsilon)$

k = *number of lags on* x_t *and* y_t

To estimate unrestricted VARs for each pair of area spot price differences (DSPOT) and monthly futures (MF) prices, we estimate and test the appropriate lag lengths that make the observed error $\hat{\mu}_{it}$ white noise (Jerko, Mjelde, & Bessle, 2004).25 Lag lengths of each bivariate VAR model were chosen based on lag length criteria tests (AIC, SC, HQ), residual tests, exclusion of jointly insignificant lag lengths based on Wald tests, and model's overall minimization of Akaike Information Criteria (AIC). All VARs appear to be stable as all inverse roots lie within the unit circle, satisfying the stability criterion. For lag length estimation statistics see Appendix Table 13, and for summary of final models' estimated results, see Table 9[26]. The explanatory power of the estimated models, measured by R^2, is always higher for the monthly future (MF) series than for the spot price difference series (DSPOT). This is mainly due to much higher volatility (st.dev) and infrequent price spikes (positively skewed and leptokurtic) in spot price differences (DSPOT), which also inflate the standard errors.

Table 9 Summary of the estimated VAR models of spot price differences (DSPOT) and monthly futures (MF) prices, with the respective probability statistics of the Granger causality test.

Area	k	AIC	Std.Error	R^2	Obs	Granger Causality (Prob.)*
DK2	5	10,68			2312	
	DSPOT	7,87	12,34	0,31		0,00
	MF	2,84	1,00	0,97		0,00
FI	5	9,23			2306	
	DSPOT	7,52	10,36	0,18		0,00
	MF	1,73	0,57	0,97		0,00
SE3	31	8,49			2282	
	DSPOT	7,20	8,79	0,34		0,00
	MF	1,31	0,46	0,97		0,00
NO1	11	5,54			2387	
	DSPOT	4,38	2,15	0,76		0,00
	MF	1,18	0,44	0,97		0,00
DK1	14	10,11			1508	
	DSPOT	6,63	6,63	0,71		0,00
	MF	3,50	1,38	0,97		0,00

[25] The white noise assumption is tested by residual serial correlation LM tests and Portmanteau tests for residual autocorrelations. Hence, the basic assumption is that the residual vector follows a multivariate white noise and has a multivariate normal distribution

[26] For detailed statistics of individual models, please contact the corresponding author.

SE1	2	4,86			417	
	DSPOT	5,20	3,24	0,82		0,00
	MF	-0,34	0,20	0,90		0,10
SE2	2	4,98			416	
	DSPOT	5,19	3,22	0,82		0,00
	MF	-0,21	0,22	0,92		0,01
SE4	1	8,49			430	
	DSPOT	5,82	4,43	0,78		0,31
	MF	2,68	0,92	0,94		0,37
NO3	7	3,74			430	
	DSPOT	4,34	2,10	0,25		0,66
	MF	-0,61	0,18	0,80		0.05

Note*:* *k*-th lag order VAR model, based on 5 % level of Schwarz Information criterion (SC), Akaike information criterion (AIC), sequential modified LR test, or Hannan-Quinn information criterion (HQ); Lag exclusion Wald tests - remove jointly insignificant lag at 10% significance level; *Test based on Granger Causality/Block Exogeneity Wald test. Each row represents the dependent variable and tests whether the second variable in each model provides significant information about the dependent variable.

Next, Granger causality test holds the null hypothesis that variable x_t or y_t is influenced only by itself and not by lagged values of the other variable in the model. In most of the estimated VAR models we reject the exclusion of the remaining variable, i.e. the probability of Granger causality test is significant This means that both futures and spot prices bi-directionally Granger cause each other, which can be understood as one type of long-term price efficiency within the tested markets. However, the null-hypothesis that spot prices do not Granger cause futures prices and vice versa cannot be rejected at 5% significance in both directions for Sweden 4 (Malmö). Also, futures prices Granger causing spot prices is non-significant in Norway 3 (Tromsø). This may point out to possible inefficiency in SE4 and NO3 where past changes of futures prices and spot prices do not contribute to the prediction of the other variable, i.e. the interdependence of spot and future price is limited.

Nevertheless, we do not know the direction or the magnitude of the causality effects, for which we turn to impulse response functions (IRF) and variance decomposition, respectively. In general, the IRF figures illustrate (see Appendix, Figure 9) a significant positive effect of spot price shocks on EPAD futures for NO1, FI, SE3 (10 days), and with shorter significant duration for DK2 (7 days), DK1 (5 days). The impacts of EPAD futures prices on the spot price differences are also significantly positive, especially pronounced for NO1, DK2, and with fluctuating duration and magnitude for FI, SE3, SE1, SE2, and DK1. The duration of the positive effect in “fluctuating” group seems to last approximately one working week (5 days). The impulse response function is non-significant for SE4 in both directions, and for NO3 in spot to futures direction. These non-significant relationships were already underlined by the Granger causality test above.

Last, we decompose the variation in the endogenous variables into the component shocks to VAR, i.e. we get a relative measure of how important the shock in spot (futures) price is in explaining the variation in the futures (spot) price at different step-ahead forecasts. Unsurprisingly we find that the shocks in each price series, spot or futures, are largely explained individually by themselves with limited influence of the second variable. Table 10 summarises the impact (% of variance explained) in one price explained by a shock in another price, 10 days ahead. In combination with IRF, the variance decomposition signifies that spot prices in DK1, NO1, and SE3 respond most strongly to EPAD futures shocks. Likewise, EPAD prices respond most strongly to spot price shocks in NO1, FI, and SE3.

Table 10. Percentage of variance in one price explained by a shock in another price, 10 days ahead

Price area	Variation in the spot price explained by a shock in the EPAD price	Variation in the EPAD price explained by a shock in the spot price
DK2	4,2%	3,6%
FI	2,8%	5,7%
NO1	12%,	10,7%
SE3	5,4%	5%
DK1	18,7%	2%
SE1	3,2%	0,4%
SE2	2,9%	2,5%
SE4	0,4%	0,3%
NO3	0,42%.	3,8%

In sum, the estimated VAR models, Granger-causality tests, impulse response functions, and variance decomposition, show bi-directional causality of spot and futures prices, however with limited magnitude and varying durations. The most efficient EPAD markets seem to be located in the price areas with longest trading history (Helsinki, Stockholm, Oslo) which may be a contributing factor in reducing market frictions in the Nordic electricity market. Also EPAD futures and spot market seem to be well integrated in Denmark, especially in Aarhus DK1, where a contributing factor may be a larger hedging demand by retailers and large customers against price volatility due to the large share of fluctuating wind power production in the local power system.

8 Conclusions

The trigger mechanism for market participants to take position in EPADs is to manage locational price risk. Our ex-post calculation of risk premia revealed their important role in EPAD prices, with varying magnitude and direction across delivery periods, areas, and years. We explain the negative (positive) risk premia in EPADs by increased hedging pressure from producers (retailers and large customers), which, in turn, are influenced by the actual level of hydro reservoirs, or more precisely the deviation from the historical median, and cross-border transmission capacities. The need to hedge may be different in areas with much hydro capacity (less volatility in prices), with the long-term local price below the system price, and with good connection to neighbouring areas (NO1). Additionally, the hedging need is dependent on the share of fixed price contracts that the end customer have. Local type of production seems to also explain the high volatility and mainly positive risk premia in Danish EPADs, especially in DK1, where significant production originates from wind power.

Having shown the importance of risk premia in EPAD prices, we further tested their theoretical and empirically identified drivers. Our results support the finding that the deviation of the water level in hydro reservoirs from its historical median impacts the local area prices, the system-wide price, as well as the difference of the two prices. As constituents of EPADs, the area price spreads during the period 2000-2013 tend to be on average larger and their response to hydro level deviations (especially in Norway and Sweden) tends to be stronger as compared to the shorter period 2001-2006 studied by Marchoff and Wimschulte (2009). This provides indirect evidence of higher price variation on the Elspot market, but more studies have to be conducted in order to explore the causalities.

A consistent and significant negative relationship between risk premia and time-to-maturity has been identified for specific area/contract combinations (e.g. Aarhus/year, Copenhagen/season, Malmö/month). For these combinations, the average risk premium at the expiration date is above zero and statistically significant. However, the relationship is not constant and significant for all areas and contracts, and therefore the negative relationship between risk premia and time-to-maturity is supported only partially. Also, the size of the open interest, and hence liquidity, do not seem to correspond, at least at first glance, to the significant relationship between risk premium and the time-to-maturity.

In sum, reasonably conventional econometric tests support the overall efficiency of the Nordic EPAD market. Our findings indicate that market maturity may be the main driver as efficiency seem to increase with longer trading history. Illustrated on EPAD monthly contracts, we showed that EPADs futures prices and the realized spot price difference during their delivery period are reasonably integrated, thus efficient. Some limitations were found in Malmö SE4 area, which may be due to market's relative immaturity, but future research should investigate the causes in further detail.

9 Acknowledgements

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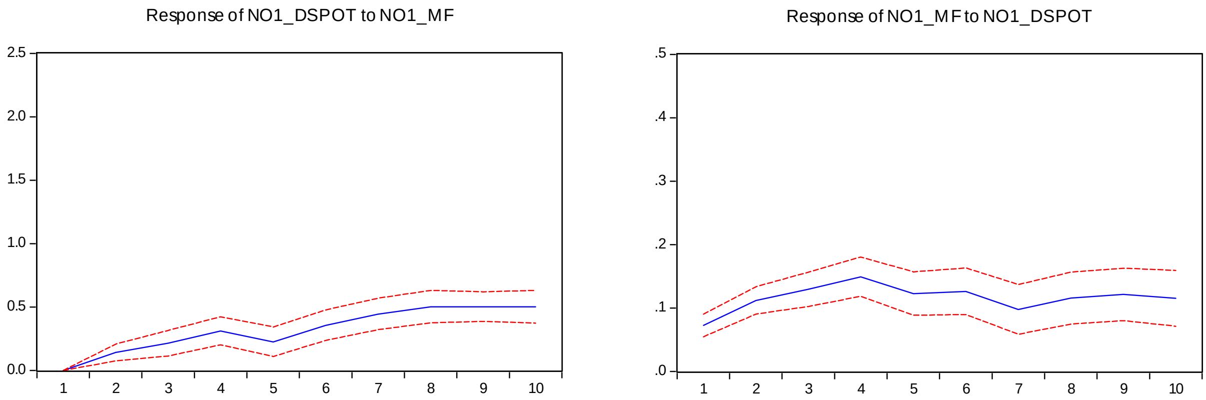
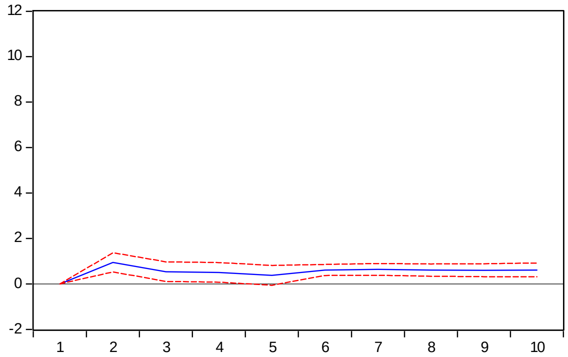
Appendix

Figure 9 Impulse response functions based on Cholesky decomposition method.

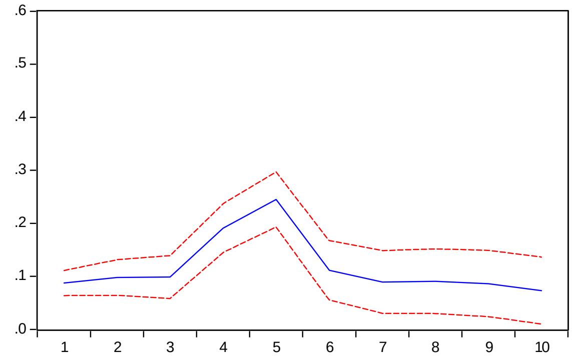
Note: The left graph shows the response of the spot price difference (DSPOT) to the EPAD monthly futures price (MF). The right graph, vice versa, shows the response of MF to DSPOT.



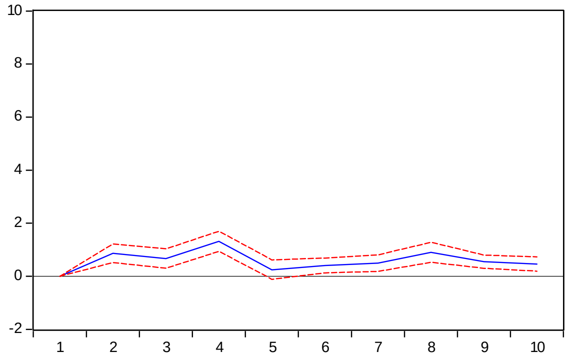
Response of FI_DSPOT to FI_MF



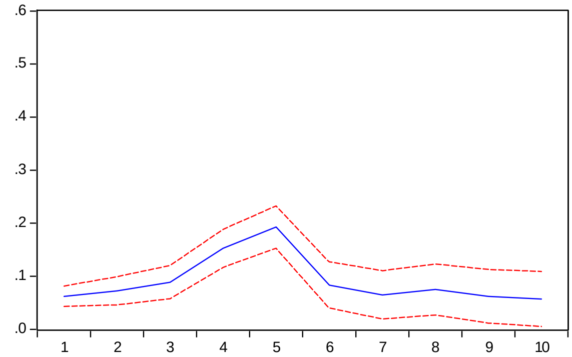
Response of FI_MF to FI_DSPOT



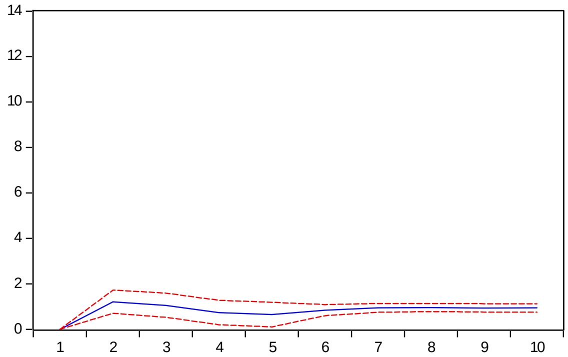
Response of SE3_DSPOT to SE3_MF



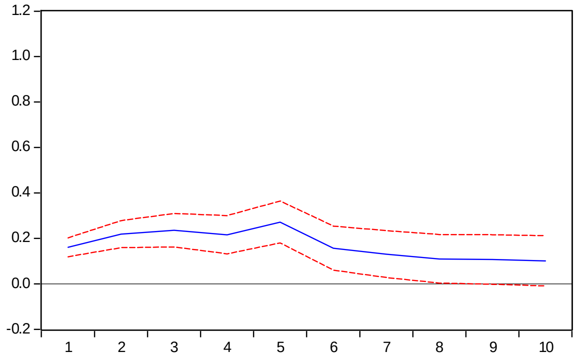
Response of SE3_MF to SE3_DSPOT



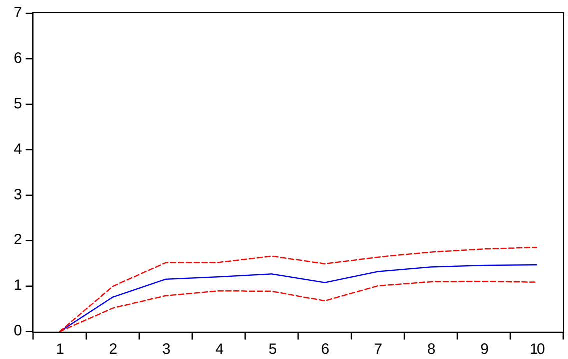
Response of DK2_DSPOT to DK2_MF



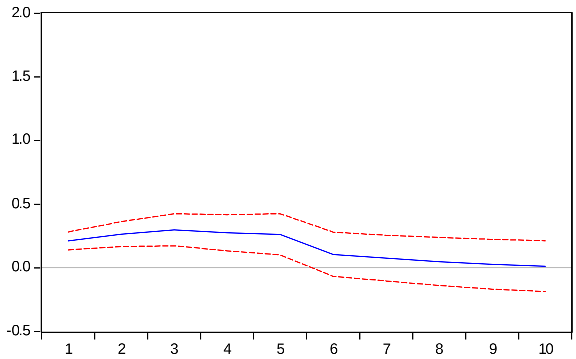
Response of DK2_MF to DK2_DSPOT



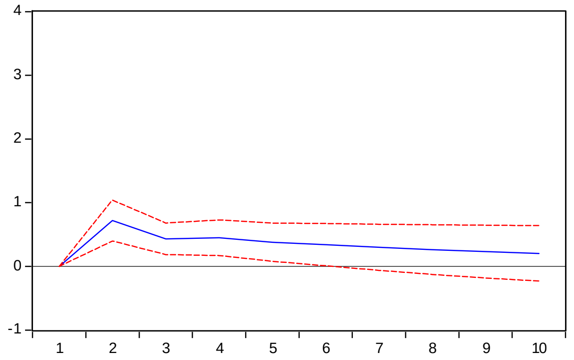
Response of DK1_DSPOT to DK1_MF



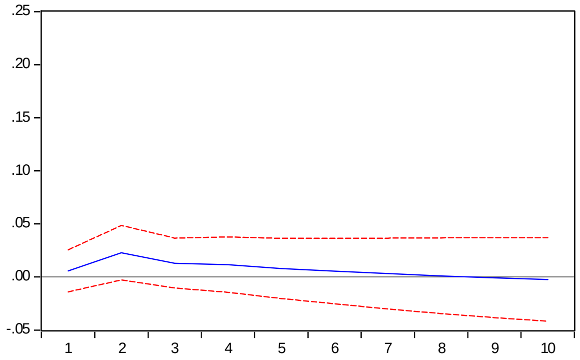
Response of DK1_MF to DK1_DSPOT



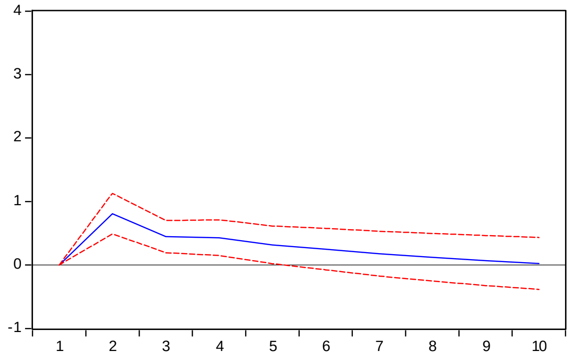
Response of SE1_DSPOT to SE1_MF



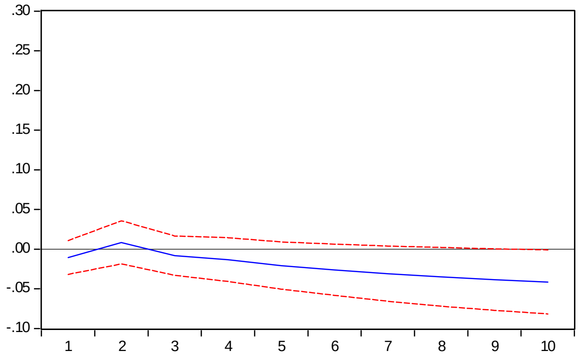
Response of SE1_MF to SE1_DSPOT



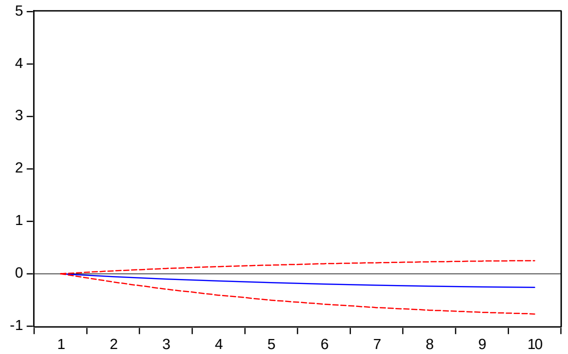
Response of SE2_DSPOT to SE2_MF



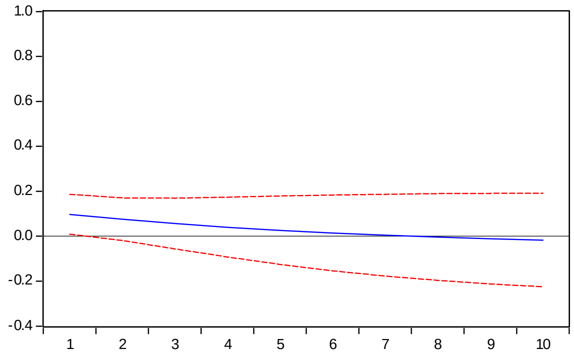
Response of SE2_MF to SE2_DSPOT



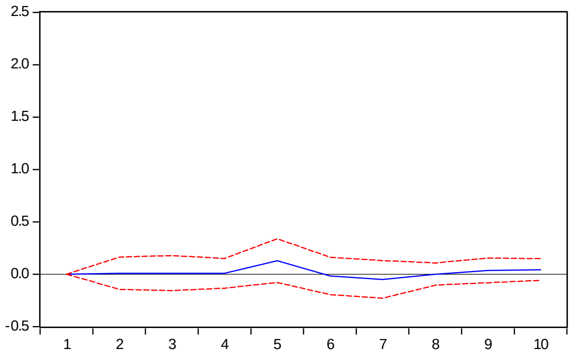
Response of SE4_DSPOT to SE4_MF



Response of SE4_MF to SE4_DSPOT



Response of NO3_DSPOT to NO3_MF



Response of NO3_MF to NO3_DSPOT

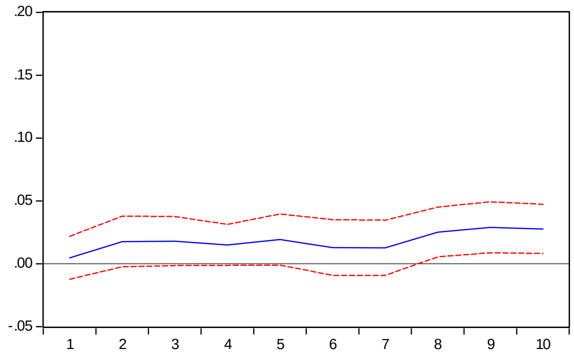


Table 11 Summary statistics of spot prices and their means, medians (), and standard deviations

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
DK1	16,43 (14,01)	23,74 (22,68)	25,47 (21,41)	33,68 (31,71)	28,8 (29,3)	37,23 (32,97)	44,18 (42,8)	32,4 (27,01)	56,43 (55,51)	36,05 (36,35)	46,48 (46,81)	47,96 (48,52)	36,33 (35,24)	38,98 (36,95)
	12,46	9,84	15,97	21,53	6,70	17,08	13,31	24,01	20,20	10,14	11,90	13,62	16,42	47,04
DK2	4,7 (0)	23,55 (22,76)	28,58 (22,69)	36,8 (33,5)	28,35 (28,75)	33,8 (30,13)	48,53 (45,6)	33,01 (27,42)	56,64 (54,57)	39,88 (36,8)	56,94 (49,5)	49,41 (50,04)	37,56 (35,54)	39,61 (38,12)
	8,64	9,57	17,53	15,93	5,61	29,52	17,55	22,03	21,89	25,50	54,53	14,94	18,32	12,12
EE	-	-	-	-	-	-	-	-	-	-	34,92 (40,1)	43,35 (42,81)	39,2 (37,05)	43,14 (40,18)
	-	-	-	-	-	-	-	-	-	-	52,16	10,22	11,40	13,26
FI	14,88 (14,04)	22,84 (22,52)	27,27 (21,74)	35,3 (32,31)	27,68 (28,18)	30,53 (29,91)	48,57 (47,14)	30,01 (26,54)	51,02 (49,45)	36,98 (36,25)	56,64 (49,2)	49,3 (49,84)	36,64 (34,87)	41,16 (39,07)
	10,23	8,27	16,17	15,45	4,49	14,23	14,73	10,20	16,11	23,30	45,55	14,31	18,02	11,65
LT	-	-	-	-	-	-	-	-	-	-	-	-	24,49 (27,05)	48,93 (45,97)
	-	-	-	-	-	-	-	-	-	-	-	-	25,02	17,77
LV	-	-	-	-	-	-	-	-	-	-	-	-	-	30,44 (33,14)
	-	-	-	-	-	-	-	-	-	-	-	-	-	30,35
NO1	12,04 (11,83)	23,08 (22,73)	26,57 (20,28)	37,11 (33,78)	29,4 (29,71)	29,13 (29,44)	49,23 (48,79)	25,73 (23,62)	39,15 (40,3)	33,74 (34,66)	54,25 (49,59)	46,42 (44)	29,56 (29,79)	37,56 (36,42)
	4,21	7,69	17,33	15,29	3,00	4,43	10,85	12,52	14,85	6,01	17,06	17,28	13,55	7,16
NO2	12,5 (12,26)	23,46 (22,89)	26,92 (20,74)	37,17 (33,84)	29,14 (29,15)	29,39 (29,5)	48,97 (47,86)	29,58 (26,13)	51,17 (49,98)	35,55 (35,04)	51,84 (49,18)	46,09 (44)	29,16 (29,74)	37,33 (36,35)
	8,94	7,45	17,00	15,33	2,90	5,03	11,32	9,96	15,05	23,29	23,99	16,74	11,81	6,89
NO3	4,19 (0)	6,42 (0)	3,11 (0)	19,48 (0)	11,75 (0)	-	4,27 (0)	29,43 (26,1)	44,02 (47,32)	24,92 (31,69)	58,03 (49,83)	47,49 (45,8)	31,48 (31,24)	38,96 (37,87)
	7,41	11,27	14,67	24,91	14,12	0,00	11,97	9,69	20,35	27,81	45,18	15,54	13,83	7,80
NO4	-	-	3,11 (0)	18,12 (0)	-	-	-	-	-	-	55,08 (49,36)	47,48 (45,61)	31,17 (31)	38,6 (37,79)
	-	-	14,67	25,12	-	-	-	-	-	-	40,17	15,42	13,66	7,32
NO5	-	-	-	-	-	-	-	-	-	-	41,13 (47,71)	45,86 (43,41)	28,95 (29,76)	37,6 (36,42)
	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	23,66	17,72	13,05	7,27
SE	14,23 (13,58)	22,86 (22,56)	27,61 (21,62)	36,49 (33,46)	28,08 (28,72)	29,76 (29,77)	48,12 (46,85)	30,25 (26,57)	51,12 (49,74)	37,01 (36,3)	56,82 (49,43)	49,77 (46,52)	-	-
	10,19	8,28	16,94	15,17	4,58	5,64	12,44	10,40	16,10	23,26	45,04	23,53	0,00	0,00
SE1	-	-	-	-	-	-	-	-	-	-	-	37,34 (0)	31,72 (31,46)	39,19 (38,14)
	-	-	-	-	-	-	-	-	-	-	-	14,27	13,98	8,29
SE2	-	-	-	-	-	-	-	-	-	-	-	37,34 (0)	31,78 (31,57)	39,19 (38,14)
	-	-	-	-	-	-	-	-	-	-	-	14,27	13,99	8,29
SE3	-	-	-	-	-	-	-	-	-	-	-	38,28 (0)	32,32 (31,63)	39,45 (38,16)
	-	-	-	-	-	-	-	-	-	-	-	14,83	15,30	8,86
SE4	-	-	-	-	-	-	-	-	-	-	-	42,04 (0)	34,21 (32,94)	39,93 (38,43)
	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	16,80	16,23	9,46
*SP	12,73 (12,54)	23,15 (22,73)	26,91 (20,78)	36,69 (33,28)	28,92 (29,09)	29,33 (29,59)	48,59 (48,26)	27,93 (25,09)	44,73 (44,68)	35,02 (35,23)	53,06 (49,25)	47,05 (45,78)	31,2 (31,01)	38,1 (37,44)
	5,39	7,67	17,06	15,12	3,25	4,65	11,13	10,67	13,69	6,26	16,05	15,72	13,77	6,95

*SP refers to system price

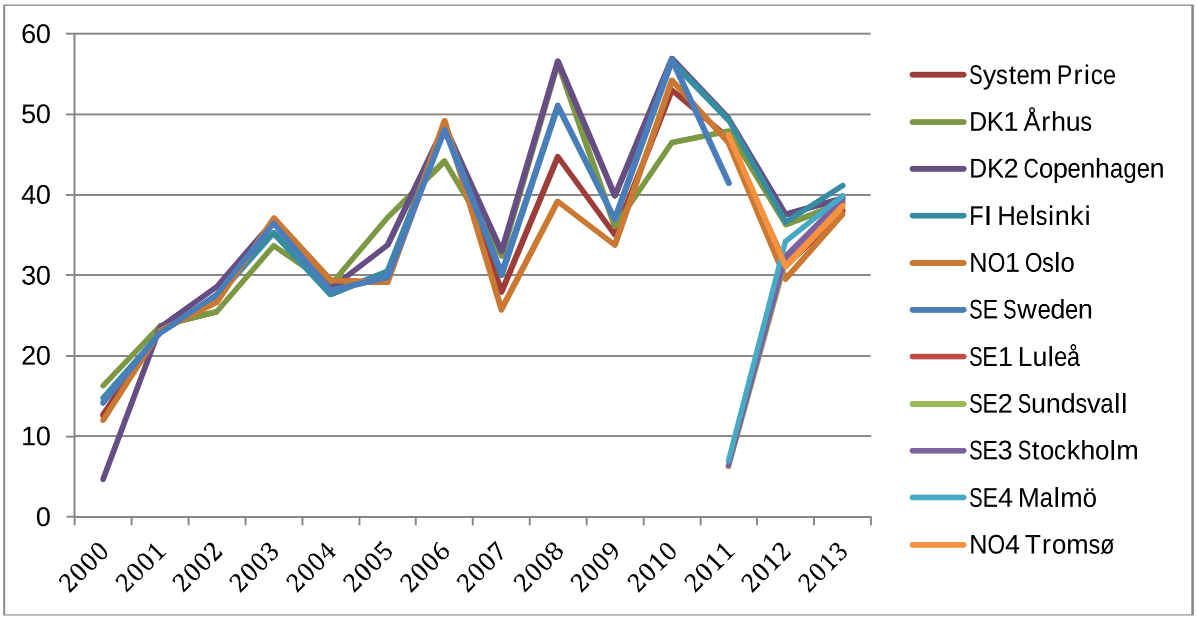


Figure 10 Annual mean of Elspot prices

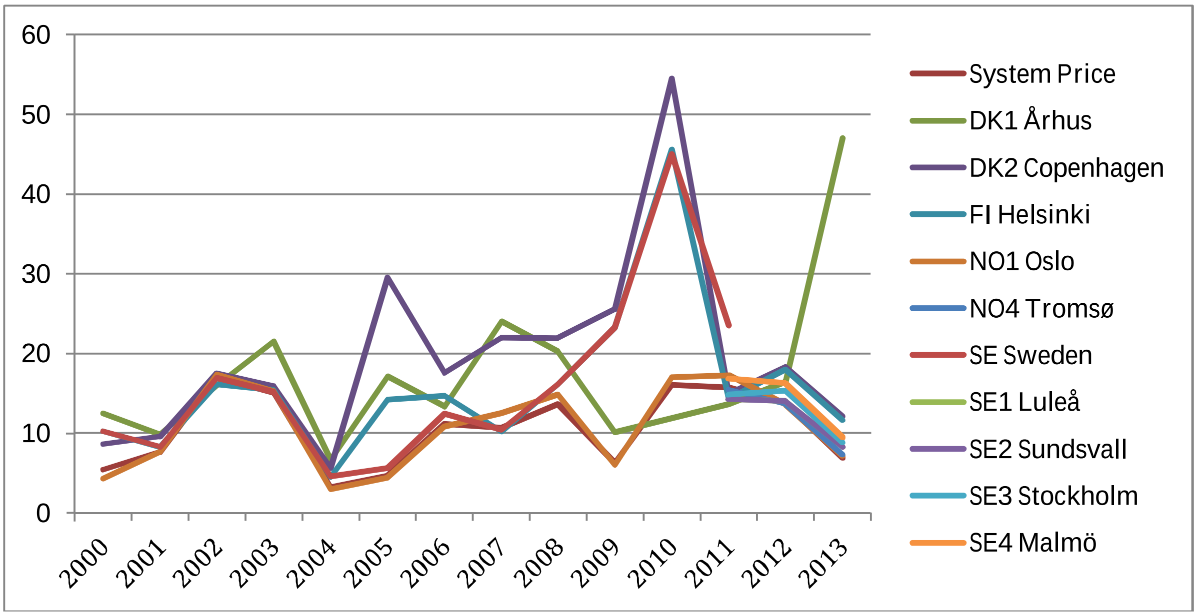


Figure 11 Annual standard deviations of Elspot prices

Table 12 Descriptive statistics for individual samples of daily area price differences (DSPOT) and synthetic monthly futures (MF) prices, 2004-2013

Area	Mean	Median	Max	Min.	Std. Dev.	Skew.	Kurt.	Jarque-Bera	Prob.	Sum	Sum Sq. Dev.	Obs.
DK2_DSPOT	5,85	2,09	370,88	-27,59	14,40	10,59	214,53	4634211,00	0,00	14402,18	510253,40	2461
DK2_MF	5,33	3,92	40,10	-12,83	5,88	0,87	5,86	1098,72	0,00	12550,46	81355,69	2355
FI_DSPOT	3,42	0,63	370,88	-9,89	11,23	18,96	541,20	29849677,00	0,00	8428,90	309992,90	2461
FI_MF	2,84	1,53	18,70	-4,50	3,43	1,47	5,27	1379,98	0,00	6842,00	28336,55	2407
NO1_DSPOT	-1,50	-0,30	46,33	-44,62	4,34	-1,12	27,75	63345,80	0,00	-3693,33	46256,05	2461
NO1_MF	-0,74	-0,30	10,50	-15,00	2,35	-1,63	9,37	5156,56	0,00	-1798,17	13334,69	2421
*SEf_DSPOT	2,28	0,23	370,88	-9,01	10,40	23,74	742,97	56355275,16	0,00	5618,95	266053,72	2460
*SEf_MF	2,08	1,15	13,60	-5,25	2,61	1,64	6,04	1981,92	0,00	4960,25	16252,89	2384
SE_DSPOT	2,46	0,25	370,88	-9,01	11,61	21,84	612,85	29874697,00	0,00	4727,09	258373,40	1918
SE_MF	2,01	1,00	13,60	-5,25	2,78	1,70	5,90	1597,16	0,00	3860,80	14804,25	1918
SE3_DSPOT	1,64	0,13	16,90	-7,38	3,70	1,97	6,90	693,72	0,00	891,31	7401,70	543
SE3_MF	2,43	2,28	7,50	-0,30	1,68	0,56	2,83	24,75	0,00	1133,98	1318,42	467
DK1_DSPOT	4,21	1,67	396,44	-95,41	15,28	10,56	268,65	4900271,00	0,00	6976,16	386249,20	1656
DK1_MF	4,11	3,55	42,13	-40,00	8,45	-0,20	7,33	1235,93	0,00	6439,35	111781,30	1565
SE1_DSPOT	-0,16	-0,03	16,90	-41,05	6,96	-3,85	22,72	10530,87	0,00	-89,12	27261,85	564
SE1_MF	0,10	0,00	3,50	-1,98	0,75	0,97	5,55	184,10	0,00	43,83	241,63	432
SE2_DSPOT	-0,12	-0,01	16,90	-41,05	6,96	-3,86	22,83	10642,44	0,00	-67,61	27249,36	564
SE2_MF	0,23	0,00	3,75	-1,95	0,89	0,89	4,22	84,96	0,00	101,31	347,81	439
SE4_DSPOT	2,26	1,03	25,75	-41,05	8,53	-2,16	13,65	3103,41	0,00	1274,12	40925,59	564
SE4_MF	5,29	5,05	17,00	-0,10	3,59	0,72	3,45	42,56	0,00	2388,99	5807,70	452
NO3_DSPOT	0,55	-0,03	16,90	-15,72	2,49	1,53	14,43	3286,86	0,00	311,31	3477,68	564
NO3_MF	-0,32	-0,40	0,95	-1,25	0,40	0,19	2,93	2,70	0,26	-139,80	70,47	442

Note: *SEf combines data for Sweden before the split (SE) into four areas and the Stockholm area (SE3) after the split.

Table 13 Model lag lengths

Area	k	AIC	SC	HQ	Lag exclusion Wald Tests	Obs
DK2	5	10,70	10,76	10,72*	-	2312
FI	5	9,22	9,28*	9,24*	-	2306
SE3	31	8,51	8,83*	8,63*	6,9,10,13,14,18,29,30	2282
NO1	11	5,61	5,72	5,65*	2,9	2387
DK1	14	10,12*	10,32	10,19*	2,4,7-9	1508
SE1	2	4,86*	4,96*	4,9*	-	417
SE2	2	4,98*	5,07*	5,02*	-	416
SE4	1	8,52	8,58*	8,54*	-	430
NO3	7	3,72*	4,01	3,83	2,3,6	430

Note: *k*-th lag order VAR model; * equals 5 % significance level of relevant statistics; Lag exclusion Wald test removes jointly insignificant lag(s) at 10% significance level.