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Are Monthly Electricity Price Area Differentials (EPADs) Efficient Hedging Instruments Against the Basis Risk in the Nordic Energy Market?

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Preface

This thesis represents the end of my master's degree at the School of Economics and Business at the Norwegian University of Life Sciences (NMBU). I have written this thesis in conjunction with my major in finance and my minor in energy economics. During my studies I have gained valuable knowledge about the Nordic energy market, and my interest for this field of study has also grown substantially. I would especially like to thank my supervisor, Associate Professor Olvar Bergland, for invaluable assistance and guidance throughout this process. I would also thank Montel for providing me with all relevant data.

I take full responsibility for all possible mistakes throughout this thesis.

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Mona Helen Heien

Abstract

The price of commodities and financial products varies over time, but in the electricity market there are also substantial variations over space. This spatial price variation becomes visible whenever there are congestion in the transmission grid, resulting in a difference between area and system prices. In the Nordic energy market Electricity Price Area Differentials (EPADs) were introduced at the end of year 2000 in order to manage this risk. This thesis investigates the pricing of the monthly EPAD contracts by applying the methods of Marckhoff and Wimschulte (2009) to a new time period, 2008-2015. I find that the EPAD prices contain significant ex-post risk premiums, however their sign and magnitude differ substantially both spatially and temporally. My findings regarding the ex-post risk premiums coincides with those of Marckhoff and Wimschulte (2009), who said that ex-post risk premiums varies because areas are subject to transmission congestion to varying degrees. I find no relationship between ex-post risk premiums and time-to-maturity, nor between ex-post risk premiums and the variance and skewness of area and system prices. This suggests that there are other determinants of ex-post risk premiums in the short run, and that the trading period for monthly contracts might be too short to show clear trends or relationships.

Sammendrag

Prisen på råvarer og finansielle produkter varierer over tid, men for elektrisitet vil det også forekomme betydelige prisvariasjoner mellom områder. En områdepriser vil være forskjellig fra systemprisen når en kapasitetsskranke i overføringsnettet til det aktuelle området blir brutt. For å håndtere denne områderisikoen ble Electricity Price Area Differentials (EPADs) introdusert til det nordiske energimarkedet i slutten av året 2000. Denne avhandlingen undersøker prisingen av månedlige EPAD kontrakter ved å prøve ut metodene til Marckhoff and Wimschulte (2009) på en ny tidsperiode, 2008-2015. Jeg kommer frem til at prisene på de fleste EPAD kontrakter inneholder signifikante ex-post risikopremier, men at fortegnet og omfanget av denne premien varierer både over tid og mellom områder. Funnene mine angående ex-post risikopremier er sammenfallende med de tidligere funnene til Marckhoff og Wimschulte (2009), som også påpekte at risikopremiene kom til å variere på grunn av at områdene i ulik grad opplever brudd på kapasitetsskrankene. Jeg finner ingen sammenheng mellom ex-post risikopremier og tid til forfall, og heller ingen sammenheng mellom ex-post risikopremier og varians og skjevhet av område- og systempriser. Dette antyder at det er andre faktorer som påvirker størrelsen på risikopremien på kort sikt, og at handelsperioden for månedlige kontrakter muligens er for kort til å vise klare trender og sammenhenger.

Table of contents

Figure list

Table list

1 Introduction

Electricity is commonly known as a highly volatile commodity, and it is therefore difficult to predict how the price will develop in the future. Market participants in the electricity market face great uncertainty with respect to the size of their future electricity-related incomes or costs. Generators, who produce electricity, wish for the future price to be high to maximize their future income. On the other hand, consumers, i.e. retailers and large industries, would like for the electricity price to be low to minimize their future costs. Market participants can hedge the price risk by buying forward or futures contracts, that way they no longer have to worry about the future price becoming too high or too low. Forward and futures contracts removes the price risk by guaranteeing a fixed future price for a pre-specified amount of electricity that is to be delivered in the future.

The electricity market is dependent on a well-functioning transmission grid to be able to transport the electricity from one location to another. Due to capacity constraints within the transmission grid, congestion on certain lines and interconnectors may occur. Different pricing areas will emerge whenever there are bottlenecks in the system, resulting in different prices between areas. If there is no transmission congestion in the grid all pricing areas will experience a uniform price, which equals the system price. A forward or futures contract only provide a hedge against this system price, which leaves the market participants faced with the basis risk. The basis risk refers to the risk of an area price being different from the system price, resulting in imperfect hedges for the market participants. Electricity Price Area Differentials (EPADs) were introduced at the Nordic market place, Nord Pool, late in year 2000. These financial derivatives are forward contracts on the difference between the area price and the system price, and theoretically they should provide a good hedge against the basis risk.

Marckhoff and Wimschulte (2009) investigated the pricing and ex-post risk premium of EPADs from 2001 to 2006 using an electricity forward pricing model. They found that the contracts contained significant ex-post risk premium, which they claim speaks in favor of efficiency of the EPAD market. Two studies by Kristiansen (2004a, 2004b) also focused on the pricing of EPADs. His periods of investigation was 2000-2002 and 2000-2003, while the EPAD-market was still young. Kristiansen also used an electricity forward pricing model, and he concluded that most EPAD contracts showed significant ex-post risk premiums. Spodniak et.al (2014) focused on the efficiency of EPADs during the period 2000-2013, and they concluded that their VAR model supported the overall efficiency of the Nordic EPAD market.

EPADs should provide a good hedge against the basis risk, but can only be described as being efficient if they are good hedging instruments for the participants in the Nordic energy market. There is limited research preformed on this energy derivative, therefore I would like to further investigate the overall efficiency of EPAD contracts. Kristiansen (2004a, 2004b) was the first to investigate the pricing of these derivatives, but his data was limited as the market was only a few years old at the time. Marckhoff and Wimschultes' study (2009) was larger in both scale and scope, and Spodniak et al. (2014) has an even larger sample size as it included more EPAD contracts over a longer time period. In this thesis I will continue the work of Marckhoff and Wimschulte (2009) by applying their electricity forward pricing model to the period 2008-2015. My research question is as follows:

Are monthly electricity price area differentials (EPADs) efficient hedging instruments against the basis risk in the Nordic energy market?

To explore this research question I will analyze ex-post risk premiums on a daily basis in order to evaluate their behavior over the trading period. I will focus the analysis on monthly contracts for EPADs in nine of the bidding areas in the Nordic energy market. In addition I will investigate the same determinants of ex-post risk premiums as Marckhoff and Wimschulte (2009) looked at in their study. Essentially, I believe my work will contribute to a better overview and understanding of the pricing of EPADs as the market now has been established for a longer period of time. The market may therefore be more mature for the period 2008-2015 than for the periods of the previous studies, which means that my results might be more applicable to the future.

In the following chapter I will put the research question into context by giving a brief introduction to the Nordic energy market. The theoretical framework about financial hedging and efficient markets will be presented in chapter three, and the methods, which is similar to that of Marckhoff and Wimschulte (2009), will be outlined in chapter four. I will describe the data more carefully in chapter five, and the results will be presented and discussed in chapter six. Finally some concluding remarks are stated in chapter seven.

2 The Nordic Energy Market

The Nordic countries, consisting of Norway, Sweden, Finland and Denmark, are well connected by transmission lines and interconnectors. These countries are also participants at Nord Pool, which is the leading market place for electric power in Europe (NordPool, 2015c). The different energy markets were previously subject to state management, but after restructuring these utilities the need for a common marketplace became visible. Nord Pool was established by Norway and Sweden, and the other Nordic countries then joined one by one. In this chapter I would like to further outline some essential topics concerning the Nordic energy market. This is done in order to build a foundation of basic knowledge about the electricity market, before I move closer to the actual EPAD contracts in the next chapter.

2.1 Restructuring

Historically the energy market has been a vertically integrated monopoly where one operator, like the regional monopolist BKK in Norway, undertakes all activities in the production chain, including generation, transmission, distribution and retailing (Decker, 2015, BKK, 2015). Due to the presence of monopolies the market has previously been characterized by strong governmental regulation, and in Norway a uniform electricity price was set once a year by the government (The Norwegian Water Resources and Energy Directorate, 2015). This regulatory system was never ideal since it did not result in a socially optimal solution, and Bye and Hope argued that the market was inefficient in both generation, transmission and distribution (Bye and Hope, 2005). Due to inefficiencies the different energy markets were restructured, with Norway being the first European country to deregulate and liberalize its market with the new Energy Act of 1990 (NordREG, 2014). As a result both generation and retailing became competitive activities, while the transmission activity remained a natural monopoly (Ministry of Petroleum and Energy, 1990). The Swedish power market was deregulated in 1996, and soon the rest of the Nordic countries followed (Statkraft, 2015). The price of electricity was now set based on supply and demand in the market, which is known to result in a socially optimal price under some restrictive assumptions. Moreover, as supply and demand varied geographically it became possible also for the price to vary, thus different pricing areas emerged.

2.2 Power production

The Nordic countries produce electricity from different sources, and basic knowledge about these sources may tell us something about the price differences between areas. Norway is the largest producer of renewable electricity in the Nordic electricity market as most of its production is based on hydropower. Countries like Sweden and Finland has some nuclear power production in addition to hydropower, while Denmark relies mostly on wind power and fossil fuel. (ENTSO-E, 2016). Table 1 gives a more detailed overview of each country's power production by source.

Table 1: Power generation for 2015 by source and country (numbers collected from ENTSOE-E, 2016)

SOURCE	NORWAY	SWEDEN	FINLAND	DENMARK
HYDRO	96%	48%	25%	-
NUCLEAR	-	34%	33%	-
FOSSIL	2%	2%	20%	39%
WIND	2%	10%	3%	50%
BIOMASS	-	6%	16%	9%
OTHER RENEWABLES	-	-	1%	2%

Hydro and wind power are cheap sources of supply since water and wind are free of charge, in addition to the marginal costs of production being close to zero (Førsund, 2007). There are also less costs associated with the shut-down and start-up processes for hydro and wind power plants compared to other power plants. Nuclear power and fossil fuel are the most expensive power sources, resulting in larger costs for nuclear and thermal power plants. Norway, Sweden and Denmark has a substantial amount of power originating from hydro and wind, respectively 98 %, 58 % and 50 %. This fact should theoretically result in lower prices for these countries, whereas Finland will be faced with somewhat higher prices. The prices will be analyzed more closely in chapter 5, but it is clear that Norway should be experiencing the lowest price among the Nordic countries based on their large amount of hydropower production.

The aggregated production for 2015 from the Nordic countries is shown in Figure 1. Here hydropower is the dominant source accounting for 60 % of total power production, followed by nuclear, fossil-fuel, wind and biomass. Both wind and hydropower are sources that are directly dependent on the weather, and weather conditions are known to vary significantly over time and between areas. Since the weather directly affects nearly 70 % of total power production, both wind and hydro, it is evident that weather conditions and the uncertainty associated with them will contribute to a volatile electricity price.

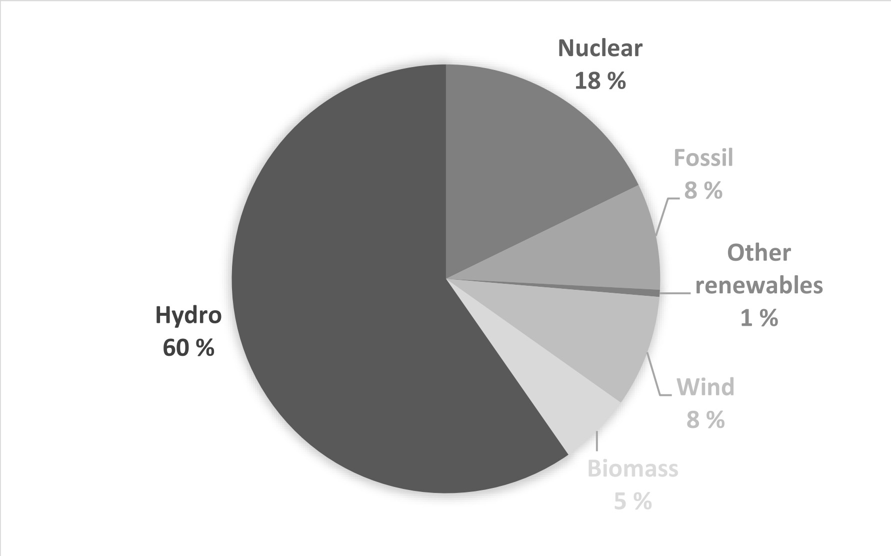

Figure 1: Power generation in the Nordic energy market by source for 2015 (numbers collected from ENTSOE-E, 2016)

2.3 Features of hydropower

One of the main features of electricity is that it is a non-storable commodity, meaning it must be used immediately after production. Water, however, can be stored in reservoirs until it is needed for electricity production. Hydropower is recovered from the energy of falling or fast running water, like waterfalls or run-of-the-river. Run-of-the-river power is usually generated as it flows through the power plant, but for waterfalls the water can be stored in reservoirs. As long as these storage units are not full, water supply can easily be adjusted to meet a varying electricity demand. (Førsund, 2007).

The marginal cost of hydropower production is close to zero. Significant investments are needed in order to construct hydropower plants, but once they are built the operating costs are small. Hydropower, being cheap in addition to being a renewable, is thus a feasible power source. The only variable affecting the price of hydropower is the amount of water available, which again depends on the weather. (Førsund, 2007).

The weather is a price driver on both the demand and the supply side. Since a major part of electricity consumption in the Nordic region is used for heating, the temperature will be a good indicator for demand. Therefore demand will be high during cold periods and low during warm periods. The supply side is dependent on the amount of precipitation as it affects the amount of water available. The temperature during spring is also of importance as warm weather results in snow melting in the mountains, which again fills up the reservoirs. The seasonal pattern for the Nordic region is characterized by heavy precipitation during fall and some inflow from snow melting during spring and early summer. This means that reservoirs are being filled during the fall, and are emptied during winter, spring and summer, before it fills up again next fall. Even though reservoirs are close to full during the winter-season and the supply is sufficient, the high level of demand will put an upward pressure on the electricity price. During summer, however, demand is normally low, which again results in low prices. (Schofield, 2011).

Due to the uncertainty of future weather conditions it is difficult to predict the future path of electricity prices. Seasonal patterns and weather forecasts give some idea about future water availability, but there is no guarantee that these factors show the true future amount. Electricity demand and supply are faced with substantial variations, both spatially and temporally, due to the uncertainty associated with weather conditions. These variations are typically reflected in the price of electricity, making the price highly volatile compared to other commodities.

2.4 Transmission congestion

In addition to the system price there might be several various area prices in the Nordic transmission system related to different bidding zones. These bidding zones, or pricing areas, results from congestion in interconnectors. Interconnectors are transmission lines linking the various bidding areas together, and their capacity may not always be sufficient to transport enough electricity to meet the demand in a particular zone (Statnett, 2015). When this capacity limit is reached the area with excess demand will be short on electricity and thus the price will increase. On the other hand, the area with sufficient supply of electricity may experience prices lower than the system price. If no capacity limits in the system are reached a uniform price will emerge as the system price then will apply to all areas. (Kristiansen, 2004a).

Figure 2 shows the different pricing areas in the Nordic energy market, as well as the interconnectors between areas as straight dotted lines. Norway has five different pricing areas, Sweden has four, Denmark has two, and Finland, Estonia, Lithuania and Latvia all have one single pricing area (NordPool, 2015c). Congestion in the transmission system is an essential price driver of electricity as it is the main reason for the formation of different pricing areas. Furthermore, with the possibility of different pricing areas to emerge, the need for market participants to hedge against varying area prices becomes visible.

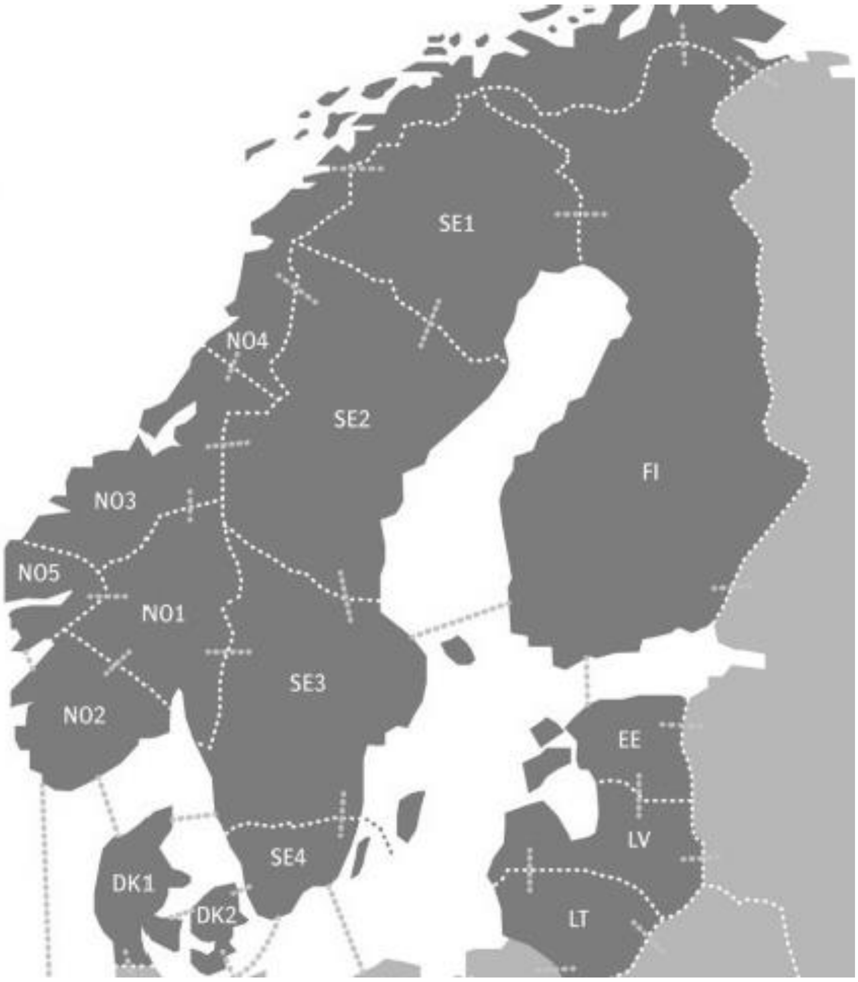

Figure 2: Bidding areas and interconnectors in the Nordic and Baltic energy market (NordPool, 2015c)

2.5 Trading platform

I will now move on to discussing how electricity is traded at Nord Pool, which is the main trading platform for electricity in Northern Europe. Nord Pool is a non-mandatory pool, meaning that the market participants themselves choose whether or not to trade on this platform. The market participants at Nord Pool are typically power producers, generators and suppliers, but there are also some large end-users and financial institutions who trade on the platform. (NordPool, 2015c). Nord Pool's history starts with Statkraft taking a small shareholding in the Swedish Sydkraft in 1996 due to the deregulation of the Swedish power market the same year. Statnett in Norway and Svenska Kraftnät in Sweden then established the joint energy exchange market, Nord Pool (Statkraft, 2015). Nord Pool grew rapidly as

Finland joined in 1998 and Denmark in 2000 (Bye and Hope, 2005). Since then Estonia, Latvia, Lithuania, Germany and the UK has also joined the pool, which makes it the largest market for electrical energy in Europe (NordPool, 2015a). Nord Pool's main responsibility is to operate the spot market, provide a reference price, and report to the Transmission System Operators (TSOs) the amount of electrical power that is to be consumed or delivered during a specific hour of a specific day (Schofield, 2011). The TSOs are operators of the transmission grid, and they are responsible for balancing supply and demand at all times.

In addition to trading at Nord Pool it is common for market participants to negotiate bilateral Over-The-Counter (OTC) contracts. OTC contracts are agreements between two parties which are customized to meet the needs and demands of both sides. NASDAQ OMX Commodities, referred to as NASDAQ from now on, offers clearing of OTC contracts. This means that NASDAQ acts as the counterparty to all trades and thus eliminates a potential counterparty risk. NASDAQ also offers different financial electricity derivatives that can help market participants to hedge their risk exposures. (Nasdaq OMX, 2015b). Both the physical spot market and the financial derivatives market are reviewed more closely below.

2.5.1 The physical market

Elspot is the physical day-ahead market where electricity is traded for delivery the following day. This is because electric demand and supply must balance at all times, and therefore the amount of electricity that is to be generated or consumed in one day must be sold or bought the day before. The day-ahead market is like a spot market except from the fact that physical delivery happens the day after the trade is executed instead of instantaneously. The system price is set on the day prior to the delivery day and is determined by auctions where the participants report a schedule for the day ahead of price and volume pairs. To construct a schedule suppliers have to calculate hourly expected demand from their customers and producers must estimate their hourly production. The aggregated supply and demand curves are then constructed for each hour, and the system price is found in the market equilibrium. This results in a balanced market where the system price reflects supply and demand for each hour. Nord Pool also becomes the counterparty of all trades made on the platform, meaning it is the buyer to all sellers and the seller to all buyers. (Schofield, 2011, Green, 2005).

Elbas is a supplement to Elspot and here market participants can trade electricity in almost real time. Elbas is constructed so that supply will meet demand at all times, and it thus has a balancing purpose. If any participants are unable to fulfil the contract they initiated the day before it is possible to sell this obligation to other market participants up until one hour prior to delivery. (NordPool, 2015b).

2.5.2 The financial market

In addition to trading electricity in the spot market, many market participants will benefit from buying or selling derivatives in the financial market. A derivative is defined as a financial instrument whose price is derived from an underlying variable, which is commonly stocks, indices, currencies or commodities (Hull, 2012). In regards to the Nordic energy market, electricity is the underlying variable. Derivatives like futures, DS futures, options and EPADs are derivative contracts commonly traded on electricity, and they are mainly used to reduce the risk exposure of market participants. Previously derivative contracts could be bought at Nord Pool's Eltermin, but now they are traded through NASDAQ. Due to uncertainty and high price volatility in the electricity market there is a significant demand for these derivatives as both producers and consumers want to manage their price risks. Financial electricity derivatives are different from contracts on other commodities as the delivery takes place during a period and not on a specific day, and the contracts are always cash settled. (Nasdaq OMX, 2015a).

2.5.2.1 Futures and DS Futures

Futures and DS (deferred settlement) Futures contracts are agreements to buy or sell a commodity, like electricity, to a specific price during a certain future period of time. These contracts have several positive attributes, with the most important one being that they provide a certainty for the market participants regarding the future electricity price (Schofield, 2011). The difference between Futures and DS Futures contracts is that Futures are marked to market on an ongoing basis during the trading period, while DS Futures are only marked to market during the delivery period (Nasdaq OMX, 2015a). For a holder of a Futures contract this means that the margin requirements can change during the trading period, and that he may get a margin call if the account falls below the required level (Schofield, 2011). The holder of a DS Futures contract will, on the other hand, not receive any margin calls during the trading period as he will receive (pay) the aggregated profit (loss) at expiration. The futures contracts can be bought with yearly, quarterly, monthly, weekly and daily delivery periods, while DS futures only can be bought with yearly, quarterly and monthly delivery periods.

2.5.2.2 Options

Options are contracts that gives the holder a right, but not an obligation, to either buy or sell an underlying asset by a specific time for a certain price. A call option gives the right to buy, while a put option gives the right to sell. Options can be useful in the way that it is optional to exercise them; one can simply compare the strike price to the underlying spot price and decide whether or not it is profitable to exercise. However, there are costs associated with acquiring options, and if it is not profitable to exercise it the holder will experience a loss. Options are commonly combined with other derivatives in order to manage risk (Hull, 2012).

2.5.2.3 EPADs

Futures and DS Futures will provide a good hedge against the future system price. Market participants are, however, located in a bidding zone and are thus faced with the price that applies to that specific area and not with the system price. To be fully hedged a position in Futures or DS Futures contracts should be supplemented with an EPAD contract. An EPAD contract can be compared to a DS Futures contract which has the difference between the area price and system price as its underlying value instead of the system price itself. EPADs were introduced at Nord Pool in 2000, but were then referred to as Contracts for Difference (CfDs). In 2013 the contracts were renamed EPADs, Electricity Price Area Differentials, and are currently being traded at NASDAQ (Nasdaq OMX, 2015b). According to the contract specification at NASDAQ EPADs are traded for 11 areas: Århus, Copenhagen, Helsinki, Oslo, Tromsø, Stockholm, Sundsvall, Malmö, Luleå, Tallin and Riga, and the contract comes with three different delivery periods: monthly, quarterly and yearly. Traders can buy contracts for the nearest two months, three quarters and three years, and the trade lot is 1 MW per contract. Daily market settlement applies during the delivery period, and the contracts are always cash settled. (Nasdaq OMX, 2015a). I will discuss EPADs more thoroughly in the following chapter, where I also will address the pricing of these contracts.

3 Theoretical Framework

Hedging means removing some of the risk one is exposed to, and this is relevant because most investors display some degree of risk aversion. Price, volume and basis risk are all relevant in the electricity market, and these risks can be hedged by using different derivatives. This chapter will move further into some financial topics in order to outline the theoretical foundation for this thesis.

3.1 Risk aversion

Risk aversion is the degree to which an investor would like to avoid risky investments. Investors will assign an individual utility score to each investment alternative equal to:

$$U = E(r) - {}^{1}\!/_{2}\, A\sigma^2 \tag{1}$$

where *E(r)* is expected return, σ^2 is the variance of returns, and *A* is an index number for the trader's risk aversion (Bodie et al., 2014). Some investors may have a greater aversion against risk, meaning that *A* is large, and hence total utility will be decreasing with risk aversion. Utility is also decreasing with variance of returns since this is a measure of the riskiness of an investment.

Risk premium is the excess return an investor can earn beyond the risk-free interest rate, and investment with risk premium equal to zero are commonly referred to as fair games. There are three different attitudes towards risk; risk seeking, risk neutral and risk averse. A risk seeking investor could also be called a gambler in which he is willing to take on a significant amount of risk in exchange for higher expected returns. This type of investor would have a negative risk-aversion-measure ($A < 0$), and he would never turn down a fair game. For a risk neutral investor ($A = 0$) the expected return is more important than the amount of risk he faces. A risk averse investor would avoid risky investments as far as possible. With a positive risk-aversion-measure ($A > 0$) the utility measure is penalized more for large variances than for the other two types of behaviors. This results in the risk averse investor rejecting fair games. The fact that market participants display some degree of risk aversion results in a need for hedging possibilities. (Schotter, 2008).

3.2 Hedging

There are three main types of traders: hedgers, speculators and arbitrageurs. Hedgers are typically producers or buyers of a commodity who wish to secure themselves against price fluctuations in the market. Their goal is to eliminate risk to a certain degree, as well as to ensure a steady cash flow to the company. Speculators, however, are players who enter the market in order to make a profit. They can be seen as the counterpart to hedgers since they take on the risk that hedgers seek to avoid. Lastly, there are arbitrageurs who enter the market only if they are able to make a riskless profit. (Hull, 2012). Following I will discuss the different types of risks participants in the electricity market are faced with, and how these risks can be managed by the use of financial derivatives.

3.2.1 The price risk

The price risk is connected to the future price of a commodity, which is unknown to the market participants. Hedgers would typically try to eliminate this price uncertainty, where producers might want to secure their cash flow by hedging against a price drop and consumers might want to control their costs by hedging against a price increase. To reduce the price risk hedgers often invest in Futures or DS Futures contracts. The contracts provide predictability so that the company knows what price it must pay or charge for electricity during a future period of time. (Sleire et al., 2015).

3.2.2 The volume risk

The volume risk is related to the amount of electricity a producer will sell or a retailer will acquire during a given period. Cold weather means higher electricity demand while warm weather means lower electricity demand, thus making weather the main determinant when it concerns volume. Producers would typically want to protect themselves against lower demand that could result from e.g. a warm winter. Consumers, on the other hand, may protect themselves against higher demand resulting from e.g. an extra cold winter. In order for market participants to protect themselves against varying demand they can invest in something called temperature derivatives, but I will not elaborate further on this topic here. (Garman et al., 2000).

3.2.3 The basis risk

The basis risk, also called the spatial risk or the price area risk, is the possibility of an area price being different from the system price. Market participants must pay attention to the price that applies to the specific area where they are located since this is the price they will either pay or receive. Since Futures and DS Futures contracts only provide a hedge against the system price market participants who invest in these derivatives are still faced with the basis risk.

Financial transmission rights (FTRs), in addition to EPADs, are forward hedging products that may be used to hedge the basis risk. FTRs are contracts between market participants and the Transmission System Operator (TSO) which gives the market participant the right to collect any financial revenue from a specific transmission line. The transmission line goes from A to B and the price difference between these points will determine the profit or loss of the FTR-holder (ENTSO-E, 2012, Kristiansen, 2004a). FTRs and EPADs are similar in many ways, but there are also some differences. Firstly, it is the difference between the area price and the system price that determines the profit or loss of the holder of an EPAD and not the price difference between two areas. Secondly, EPADs are often sold by other market participants and not by TSOs. Lastly, EPADs are not dependent on the physical transmission grid and the transmission capacities between areas. (Spodniak et al., 2014). FTRs are of lesser interest to this thesis, but I chose to include them here to show that there are alternatives to EPADs.

3.3 Electricity Price Area Differentials

EPADs should provide a good hedge against the basis risk, and the value of an EPAD will depend on the difference between the area and the system price. This difference will vary over time, and can be either positive or negative. One problem with the EPAD market is that it is less liquid that the market for Futures and DS Futures. This liquidity problem is, to some extent, solved by market makers, who quote both bid and offer prices on the contracts. This makes it possible for market participants to trade at all times. We also know that EPAD contracts are mostly used for hedging, and not speculation as most contracts are only sold once instead of being traded repeatedly. (ENTSO-E, 2012).

3.3.1 The pricing of EPADs

This chapter is based on the theory of Marckhoff and Wimschulte, who stated that an EPAD theoretically equals a long position in an area forward and a short position in a system forward as:

$$EPAD_{t,T} = F_{t,T}^{A} - F_{t,T}^{S}, \qquad (2)$$

where $EPAD_{t,T}$ is the EPAD price at time *t* with delivery in *T*. $F_{t,T}^{A}$ and $F_{t,T}^{S}$ are respectively the area and system forward price at time *t* with delivery in *T*. The area forward is, however, not available for sale and its forward price is therefore unknown to us. By rearranging equation 2 we find that the implied area forward price equals a long position in an EPAD and a long position in a system forward, like:

$$F_{t,T}^{A} = EPAD_{t,T} + F_{t,T}^{S}. \tag{3}$$

For most commodities the theory of storage would be applied to the pricing model. This theory suggests that the forward price equals the spot price in addition to the cost of storage, which is denoted W in equation 4. Whenever this is true the forward price will be greater than the spot price and the market is in contango. If, however, the spot price is greater than the forward price the market is in backwardation. This is possible because sometimes the benefit of having access to a commodity immediately is greater than the benefit of having access to it in the future. This benefit is known as the convenience yield (CY), and the pricing equation becomes (Schofield, 2011, Fama and French, 1987):

$$F_{t,T} = S_t + W - CY \tag{4}$$

Electricity, however, is commonly accepted as a non-storable commodity. This makes the theory of storage non-applicable to financial derivatives within the electric market. On the other hand, there is a second well known pricing theory called the theory of risk premiums. This theory states that $F_{t,T}$, the forward price at time *t* with delivery in *T*, consists of the expected spot price at time *T* given information set Ω_t, plus the forward risk premium π_t^F, like (Marckhoff and Wimschulte, 2009):

$$F_{t,T} = E(S_T|\Omega_t) + \pi_t^F. \tag{5}$$

By rearranging equation 5 we get that the forward risk premium equals the forward price minus expected spot price at time *T* given information set Ω_t as:

$$\pi_t^F = F_{t,T} - E(S_T|\Omega_t). \tag{6}$$

The risk premium is the amount a buyer is willing to pay and a seller is willing to accept in order to eliminate some of the buyer's price risk. The seller, or the issuer, must be compensated for taking on some of the buyer's risk, and the buyer is willing to compensate the issuer for his service. According to Marckhoff and Wimschulte, Cootner (1960) was one of the first to study the theory about futures prices containing a certain risk premium. In his paper he presents two theories; the Keynes-Hicks theory and the Telser theory. Keynes-Hicks suggests that speculators are sellers of insurance, and that their payoff should be positive over time. Tesler's theory, on the other hand, suggests that speculators buy gambles, making the payoff not necessarily positive (Cootner, 1960). Later Breeden argued that positive risk premium were called for in some markets because of high systematic risks (Breeden, 1980). The theory of risk premiums has been widely used and it may therefore be considered to be scientifically accepted for financial derivatives in the electricity market (Kristiansen, 2004b, Bessembinder and Lemmon, 2002, Marckhoff and Wimschulte, 2009, Longstaff and Wang, 2004).

Equation 6 for forward risk premium can easily be transferred to EPADs. The information set of Ω_t is left out for simplicity, and the risk premium for EPADs can be calculated as follows:

$$\pi_t^{EPAD} = EPAD_{t,T} - E_t(EPAD_{T,T}), \tag{7}$$

where $EPAD_{t,T}$ is the EPAD price at time *t* with delivery in period *T*, and $E_t(EPAD_{T,T})$ is the ex-post delivery price. The ex-post delivery price refers to the payoff of the contract, and is the average of the daily differences between the area and system prices during the delivery period. (Marckhoff and Wimschulte, 2009). The risk premium of EPADs are of great interest to this thesis, and I will examine these closely in chapter 6.

3.3.2 Risk premium in EPADs

According to Kristiansen the EPAD contracts have a positive price whenever the market anticipates an area price higher than the system price, and a negative price whenever the system price is expected to exceed the area price. Positive EPAD prices implies a net import situation, while negative prices implies a net export situation for a particular area. (Kristiansen, 2004a). The risk premium, however, does not have an as clear cut interpretation since it is defined as the difference between the EPAD price and the ex-post delivery price. The risk premium is therefore not observable until after the delivery period, and it will mostly depend on the difference between the area price and the system price throughout the delivery period. If the average difference between the area and system price is smaller than an EPAD price at time *t* the risk premium is said to be positive, and if the difference exceeds the EPAD price the risk premium will be negative.

Kristiansen attributed positive values of risk premium to risk-averse consumers being a majority in one particular area. These consumers were willing to pay a risk premium in order to hedge against possible price spikes. Likewise, he explained the negative values of risk premium by a majority of risk-averse generators wishing to hedge their production. (Kristiansen, 2004b). Benth et al. (2008) and Marckhoff and Wimschulte (2009) argue that risk premium varies over time to maturity because of market participants’ behaviour and their hedging horizons. They conclude that consumers have market power for longer time horizons, like year contracts, while generators have market power for shorter time horizons, like quarter and month contracts. This is explained by generators, who are exposed to uncertainty regarding their future revenues, being more eager to make long-term hedges. Movements in the electricity price will have a significant impact on their revenues as most of their income is based on electricity sales. For consumers trading in electric power, most of their total costs will also be linked to the electricity price. Their costs are therefore affected by variations in the area price, but consumers are generally more interested in short-term hedges to secure themselves against possible short-term price spikes. (Benth et al., 2008, Marckhoff and Wimschulte, 2009). Essentially, there should be a negative relationship between the risk premium and the time to maturity.

When the risk premium is positive consumers will be paying the risk premium while generators will be receiving the risk premium. With negative risk premium the opposite will be the case. Kristiansen found that the contracts appeared to be over-priced due to negative payoffs for most contracts during the settlement period. His explanation for this was that there might be a majority of risk-averse consumers in the market who are willing to pay a premium in order to avoid the basis risk. (Kristiansen, 2004b).

3.4 The Efficient Market Hypothesis - EMH

In this chapter I will address the theory behind efficient markets as well as the efficient market hypothesis. This is a central theory within finance and I believe it to be relevant for the thesis since I am investigating both the pricing and the efficiency of EPADs.

In 1953 Kendall and Hill discovered that spot price changes were random and that it was impossible to predict future price changes (Kendall and Hill, 1953). The prices follow a random walk process, meaning it is impossible to know in which direction and by how much a price will change from one day to the next. This was first seen as a sign of an irrational market, but was later viewed as one of the requirements for a well-functioning and efficient market (Bodie et al., 2014). In 1965 Fama describes an efficient market as having a large number of rational, profit-maximizing market participants who separately tries to predict future prices on securities, and where important information is freely available. It is the competition between market participants that leads to efficient markets as the competition results in prices that reflect all available information. The price of the security is therefore a good estimate of its intrinsic value. (Fama, 1965).

The Efficient Market Hypothesis (EMH), which was formulated by Fama in 1970, states that it is impossible for traders to consistently beat the market. This is because stock price changes are thought to be unpredictable and to follow a random walk. There are three different versions of the EMH: weak form, semi-strong form and strong form. The weak form assumes that stock prices reflect all information embedded in historic stock price data and other easily obtainable market data. Further the semi-strong form states that all publicly available information, like fundamental data on a firm, are reflected in the current stock price. Lastly the strong form assumes that all information, including information only available to company insiders, are reflected in the spot price. (Fama, 1970).

In order for the efficient market hypothesis to be valid it is required that the market is sufficiently big, and thus liquid. The background for this requirement is to prevent firms from exercising market power. A big market also ensures diversification in the way that people have different opinions and perceptions about future market situations. If everyone had the same market view they would all be making the same transactions at the same time, which is impossible because there must always be someone on the other side of a trade. Different market opinions among market participants help ensuring market efficiency by pricing different assets and securities at their fair values. The price on a stock or a derivative might deviate from its fair value for a short period of time, but this deviation will be discovered by arbitrageurs or other traders. As soon as this happens the arbitrageurs will lock in a profit and the deviation will disappear as the price moves back to its fair value. Ultimately it is the traders who, in their quest for excess returns, ensures the efficiency of markets.

3.5 Research question and hypotheses

As stated in the introduction, the research basis for this thesis is the risk premium of EPAD contracts.

<u>Research question</u>*: are monthly electricity price area differentials (EPADs) efficient hedging instruments against the basis risk in the Nordic energy market?*

In order to answer this question I have constructed some hypotheses that I wish to examine more closely. First, I will put the issue in context by examining the usefulness of EPADs. To determine this I need to know if the risk of area prices differing from the system price is real. It is this difference that makes EPADs relevant as hedging instruments, and without this basis risk there is no need for EPADs.

Hypothesis I: there is no significant difference between the area prices and the system price over time.

Second, I will continue the work of Marckhoff and Wimschulte in order to determine whether there are significant risk premiums within the EPAD market. The existence of risk premiums is a sign of an efficient market, and it will be interesting to examine the risk premium for this newer time period to see if market maturity can change any conclusions from earlier studies.

Hypothesis II: there is no significant risk premiums in the EPAD market.

Third, I will examine the changes in the risk premiums over the last month before maturity, and forth, I will conduct a regression to examine if the variance and skewness of the area and system prices are affecting the risk premium. Both of these hypotheses were also examined by Marckhoff and Wimschulte (2009).

Hypothesis III: there are no changes in risk premium over time to maturity.

Hypothesis IV: variance and skewness of the area and system prices cannot be classified as determinants of risk premium.

4 Methods

In order for me to evaluate the efficiency of EPAD contracts I will do as Marckhoff and Wimschulte (2009) and look at the risk premium of EPADs. I find the risk premium by using the electricity forward pricing model, and with this new variable I am able to conduct some simple regressions that can help me test my hypotheses.

4.1 Time series data

Time series data is ordered temporally and my analyses will be based on daily observations. A time series process is a stochastic process defined as a sequence of random variables indexed by time (Wooldridge, 2014). One important aspect of time series data is the possibility of past observations affecting present observations, and therefore lagged values of the dependent variable might prove statistically significant in the model. In addition it is common for time series data to show a trend, either increasing or decreasing, or some kind of seasonal pattern. As discussed in chapter 2.3, evidence show that electricity prices follow a seasonal pattern with high prices during winter months and low prices during summer months. Time series data are particularly vulnerable to spurious regressions, but whenever the processes are stationary we avoid this problem.

4.2 Electricity Forward Pricing Model

In order to determine the significance and magnitude of a potential risk premium in the EPAD market I will use the same technique as Marckhoff and Wimschulte (2009), namely applying the electricity forward pricing model to the EPAD market. The model was derived in chapter 3.3.1, and here I will make some notational adjustments in order for the model to be denoted properly.

The risk premium of an EPAD contract is the difference between the traded EPAD price and the ex-post delivery price. The ex-post delivery price refers to the payoff of the contract, and is the average of the daily differences between the area and system prices during the delivery period. Formally, Marckhoff and Wimschulte (2009) specified:

$$\pi_{i,t}^{EPAD} = EPAD_{i,t,T} - E_t(EPAD_{i,T,T}), \tag{8}$$

In 2014 Spodniak et al. made some notational changes to the model and ended up with the following equation:

$$\pi_{i,t}^{EPAD} = EPAD_{i,t,T} - \frac{1}{T_2 - T_1}\sum_{t=T_1}^{T_2}(S_{i,t}^{A} - S_t^{S}) \tag{9}$$

This equation shows the risk premium of a specific EPAD contract on day *t* during the trading period. Where $EPAD_{i,t,T}$ is the traded EPAD price for area *i* at time *t*, T_1 and T_2 are the start and end dates of the delivery period, and $S_{i,t}^{A}$ and S_t^{S} are respectively the spot price of area *i* and system price on day *t*. Focusing on monthly EPAD contracts we know that they are traded over a two-month period before the start of the delivery period, meaning that there are always two different month contracts available for trade. The contract with the shortest time to maturity is called the front contract, and the variable $EPAD_{t,T}$ is found by aggregating these front contracts for each bidding area. I now have a new time series process for each contract area, $\pi_{i,t}^{EPAD}$, which is the risk premium of area *i* at day *t*.

First, I will test for non-zero risk premium, meaning whether or not there are significant differences between the area prices and the system price over time. In order to test this I apply the regression from equation 10, where μ_i is the mean value of the risk premium of area *i* over the study period. The null hypothesis is tested against the two-sided alternative hypothesis, and rejecting the null hypothesis involves saying that the risk premium is significantly different from zero.

$$\begin{aligned}
&\pi_{i,t}^{EPAD} = \mu_i + \varepsilon_t \\
&H_0: \mu_i = 0 \\
&H_1: \mu_i \neq 0
\end{aligned} \tag{10}$$

Second, I look at the relationship between the risk premium and the time to maturity. Theory states that time-to-maturity is negatively related to the risk premium in EPADs (Benth et al., 2008, Marckhoff and Wimschulte, 2009). To test this I conduct the regression from equation 11, which was previously performed by Marckhoff and Wimschulte (2009). Here *c* is a constant, τ_t is the remaining time to maturity, and ε_t is the error term. Monthly contracts are traded for two months, but since only the front month is of interest the time to maturity will only range between 1 and 31 days. The null hypothesis is tested against the two-sided alternative hypothesis.

$$\pi_{i,t}^{EPAD} = c + \beta\tau_t + \varepsilon_t$$
$$H_0: \beta_i = 0 \qquad (11)$$
$$H_1: \beta_i \neq 0$$

Third, I will look at the risk premium in relation to the variance and skewness of the daily area and system prices. Regression 12 is derived by Marckhoff and Wimschulte (2009), and is based on the work of Bessembinder and Lemmon (2002). Here *c* is a constant, $Var(S^A)$ and $Var(S^S)$ are the variance of the area and the system price respectively, and $Skew(S^A)$ and $Skew(S^S)$ are the skewness of the area and system prices respectively. The variances and skewness is calculated as a moving average of 4 weeks (28 days). Like Marckhoff and Wimschulte (2009) I expect the variance of the area (system) spot price to have a negative (positive) impact, and the skewness of the area (system) spot price to have a positive (negative) impact on the risk premium. The monthly contracts are aggregated over all areas in order to obtain a larger sample size, as well as to be able to compare the results with those of Marckhoff and Wimschulte (2009).

$$\pi_i^{EPAD} = c + \alpha_1 Var(S^A) + \alpha_2 Var(S^S) + \gamma_1 Skew(S^A) + \gamma_2 Skew(S^S) + \varepsilon_i$$
$$H_0: \alpha_1 < 0 \mid H_1: \alpha_1 \geq 0$$
$$H_0: \alpha_2 > 0 \mid H_1: \alpha_2 \leq 0 \qquad (12)$$
$$H_0: \gamma_1 > 0 \mid H_1: \gamma_1 \leq 0$$
$$H_0: \gamma_2 < 0 \mid H_1: \gamma_2 \geq 0$$

4.2.1 Assumptions for time series models

In order for the regressions above to be valid I base my analyses on some assumptions about time series data. Assumptions 1-3 make sure that the coefficient estimates are consistent, while assumption 4 and 5 assures that confidence intervals, *t* statistics and *F* statistics are approximately valid in large samples. The following assumptions are obtained from the textbook of Wooldridge:

1. Linear in parameters and weakly dependent: this means that the time series process is stationary and follows the linear model, $Y_t = \beta_0 + \beta_1 x_{t1} + \cdots + \beta_k x_{tk} + u_t$
2. No perfect collinearity: meaning that no independent variable is a perfect linear combination of the others
3. Zero conditional mean: the expected value of the error term is zero, $E(u_t | x_{t1}, \ldots, x_{tk}) = 0$

4. Homoskedasticity: the variance of u_t is the same for all t, $Var(u_t|x_t) = \sigma^2$
5. No serial correlation: the errors are uncorrelated across time periods, $Corr(u_t, u_s|x_t, x_s) = 0$

For time series data it is common to experience heteroscedasticity and serial correlation. I will therefore test for heteroscedasticity by using the Breusch-Pagan test, and the Breusch-Godfrey test for serial correlation. (Wooldridge, 2014).

4.2.1.1 Stationarity

In addition to the assumptions above it is important that the different time series processes are stationary in order for us to avoid spurious regressions. Spurious regressions is a common problem in time series regressions, and relationships that does not really exist may appear. Stationarity of a time series process requires the mean, variance and covariance of ε_t to be invariant over time. Prices are commonly not stationary processes, but we often find that the difference in prices are stationary. To check for stationarity I use the Augmented Dickey Fuller (ADF) test for unit root:

$$\Delta Y_t = \delta + \pi Y_{t-1} + c_1 \Delta Y_{t-1} + \cdots + c_{p-1} \Delta Y_{t-p+1} + \varepsilon_t \tag{13}$$

This extended version of the Dickey Fuller test corrects for serial correlation in ΔY_t by including lagged changes. The number of lags may vary, but generally I include all significant lags. I test the null hypothesis against the alternative hypothesis:

$$H_0: \pi = 1$$
$$H_1: \pi \neq 1$$

The null hypothesis suggests spurious non-stationarity, meaning that the regular t-values cannot be used since the t-ratio does not have a t distribution under the null hypothesis. I use the critical values for the ADF test, which is -2.86 for the 5% significance level. If the null hypothesis is rejected the time series process is stationary and we do not have to worry about spurious regressions. On the other hand, if the null hypothesis cannot be rejected the differences in prices may be used in the regression instead of the prices themselves. I could also check for cointegration, and if two series are cointgrated an error correction model may be applied to fix the problem of spurious regression. (Wooldridge, 2014).

5 Data

5.1 Data overview

The data used in the analyses consists of area and system prices, and prices on monthly EPAD contracts. Nord Pool's web page (nordpoolspot.com) provides the spot prices, while the web page of Nasdaq OMX Commodities (nasdaqomx.com) provides prices for the EPAD contracts. I have gained access to these data by the courtesy of Montel (montel.no). The study of Marckhoff and Wimschulte (2009) focused on the period from 2001 to 2006 when the market was still young and possibly immature. To continue their work I have chosen to analyze the 8-year period from 2008 to 2015, as I believe this period shows a more established EPAD market.

The areas that will be studied include nine of the Nordic areas for which one can buy an EPAD contract, namely: Århus (DK1/ARH), Copenhagen (DK2/CPH), Oslo (NO1/OSL), Tromsø (NO4/TRO), Helsinki (FI/HEL), Stockholm (SE3/STO), Sundsvall (SE2/SUN), Malmö (SE4/MAL) and Luelå (SE1/LUL). Up until 2010 Sweden had one single contract area, Stockholm, but after 2010 Sweden was split into four different areas. Because of this I only have price data for Sundsvall, Malmö and Luelå for the period 2011-2015. Tromsø has been a separate bidding area, but it did not get its own contract before 2011. Therefore I only have prices for EPAD contracts for the period 2011-2015. For the rest of the areas I have both area prices and prices for EPAD contracts for the whole period.

Further I will examine monthly EPAD contracts since these are the most liquid ones (Spodniak et al., 2014). For monthly contracts there are two contracts traded at the same time, but I am only interested in the front contract, which is the contract that is up for delivery first. I aggregated the different front contracts to get a new time variable, and for all days with no EPAD closing prices I let the last known closing price apply.

5.2 Area and system prices

It is commonly accepted that the electricity market is a highly volatile market, and based on my data I coincide with this perception. (Marckhoff and Wimschulte, 2009, Kristiansen, 2004b, Spodniak et al., 2014). The system price during the period 2008-2015 is shown in Figure 3, and it appears as if this overall electricity price moves around quite a lot with peaks during the winter season.

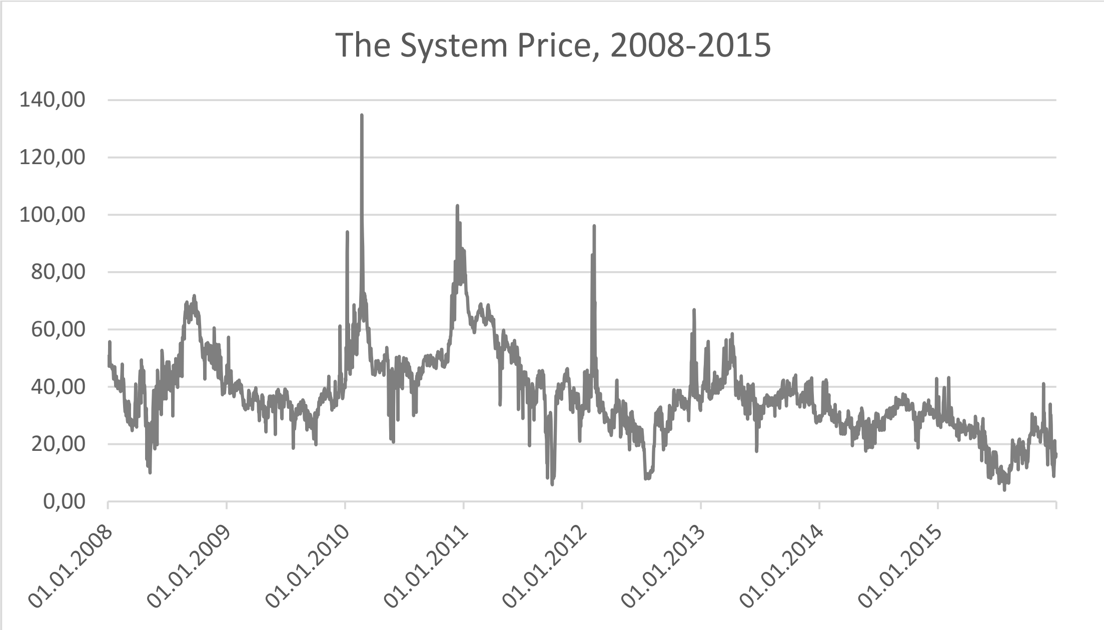

Figure 3: The system price, 2008-2015 (prices collected from Nord Pool, 2016)

Further, Table 2 lists the average area prices and system price, including their standard deviations, for each year during the study period, 2008-2015. The average system price is lowest in 2015 at 21.05 EUR, and highest in 2010 at 53.30 EUR. I believe this to be large movements, at least since we are considering yearly averages. Generally, I see a tendency of area prices being higher than the system price. The exception is the Oslo area, which has historically experienced lower prices than the system price because of their significant amount of hydropower production. The standard deviations vary greatly over time and between areas, and confirms my earlier assumption about the electricity price being highly volatile. Århus, Copenhagen and Helsinki looks to be the areas experiencing largest price movements compared to the others.

The year 2010 stands out from the other years as both price level and standard deviations are high, and the volatility is actually above 50%[1] for four of the areas. During this year we also observe that the area price for Oslo exceeds the system price. These abnormalities may be explained by low precipitation and low reservoir levels in Norway during 2010 (Spodniak et al., 2014). Oslo had to import more expensive electricity from other areas, resulting in a higher area price for Oslo. Furthermore, many of the other areas were benefiting from cheap hydropower production, either by producing for themselves or importing from nearby areas.

[1] Calculated as the standard deviation of a pricing area divided by its area price.

As mentioned before 60% of the electricity production in Northern Europe originates from hydropower, and simple microeconomic theory suggests a price increase whenever the supply is reduced. This is what I observe for most areas, and also larger price variations during this year (except from Århus). Moreover, both the prices and the standard deviations look to have been reduced from 2010 to 2015.

Table 2: Annual mean area and system prices (EUR/MWh)

	SYS	ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
2008	44.74	56.48	56.67	51.06	39.15	51.22	51.16	-	-	-
	(12.48)	(14.59)	(15.84)	(13.90)	(14.72)	(13.17)	(13.90)			
2009	35.14	36.15	39.98	37.08	33.87	35.68	37.11	-	-	-
	(4.83)	(5.95)	(13.66)	(12.20)	(5.29)	(12.72)	(12.18)			
2010	53.30	46.49	56.95	56.87	54.55	58.28	57.05	-	-	-
	(13.87)	(8.27)	(34.33)	(32.99)	(16.05)	(32.80)	(32.84)			
2011	46.82	47.97	49.42	49.09	46.14	47.26	47.63	47.47	48.26	47.47
	(14.97)	(9.10)	(9.40)	(12.38)	(16.69)	(14.62)	(14.42)	(14.42)	(14.43)	(14.42)
2012	31.20	36.44	37.65	36.67	29.55	31.48	32.34	31.79	34.23	31.73
	(11.56)	(11.56)	(12.38)	(13.00)	(11.71)	(11.63)	(12.46)	(11.70)	(12.72)	(11.70)
2013	38.14	38.97	39.62	41.19	37.60	39.00	39.49	39.23	39.97	39.23
	(5.73)	(22.70)	(8.58)	(7.69)	(6.20)	(6.30)	(6.76)	(6.42)	(6.88)	(6.42)
2014	29.57	30.63	32.11	35.83	27.30	31.52	31.59	31.40	31.89	31.40
	(4.27)	(7.45)	(6.39)	(5.74)	(5.67)	(3.92)	(4.90)	(4.66)	(5.16)	(4.66)
2015	21.05	22.90	24.49	29.79	19.92	21.31	22.05	21.23	22.93	21.21
	(7.31)	(8.26)	(8.24)	(9.19)	(7.38)	(7.19)	(8.06)	(7.35)	(8.54)	(7.34)

In Table 3 I have included descriptive statistics for the electricity prices for the whole study period, 2008-2015. Sundsvall, Malmö and Luelå has both the lowest prices and the smallest standard deviation, but this might be explained by their relatively shorter study period, 2011-2015. Looking past these Swedish areas Oslo has the overall lowest price, and the system price has the lowest standard deviation. The highest prices is found in Helsinki and Copenhagen, and the Helsinki price can be explained by the relatively more expensive power sources in Finland. Another point worth noticing is the minimum prices for Århus and Copenhagen which is negative. This is possible whenever there are unbalances between demand and supply in the system. Sometimes it is more beneficial for generators to let the price drop below zero than to shut down the production or to let some of the power go to waste.

Table 3: Descriptive statistics for area and system prices, 2008-2015

	SYS	ARH	CPH	HEL	OSL	TRO	STO	SUN	MAL	LUL
MEAN	37.45	39.46	42.06	42.16	35.97	39.42	39.75	34.22	35.46	34.21
ST.DEV	14.14	15.62	19.23	17.73	15.32	18.99	18.85	13.08	13.29	13.09
SKEW	0.85	5.87	7.02	8.46	1.08	7.11	7.17	0.71	0.64	0.71
KURTOSIS	5.05	145.2	138.5	185.0	6.6	144.9	148.4	4.6	4.4	4.6
MINIMUM	3.9	-38.4	-38.4	6.3	2.9	4.1	3.5	3.5	3.5	3.5
MAXIMUM	134.8	436.3	505.7	505.7	151.7	505.7	505.7	99.6	101.3	99.6
OBS.	2926	2926	2926	2926	2926	2926	2926	1829	1829	1829

5.3 Differences between area and system prices

Marckhoff and Wimschulte found that the daily area prices differed from the system price 99.7% of all days in 2006, and they predicted that the number would reach 100% for the following years. For the period 2008-2015 I find maximum two days for the same area where the difference between the area price and the system price is zero. This means that for all other days there are at least one active capacity constraints resulting in price differences.

Knowing that area prices differ from the system price it is interesting to take a closer look at these differences. Table 4 presents the average differences between the area prices and the system price by year in both absolute and percentage terms. I calculated the percentage terms as price differences in percentage of the average system price for the current year and area. In addition the table includes standard deviation, and minimum and maximum values of the differences. For most areas the sign of the difference does not change over the years, with the exception being Århus and Oslo in 2010. This table also reveals both spatial and temporal mean differences, and it appears as if Århus, Copenhagen and Helsinki are experiencing the largest price differences. The difference from the previous study of Marckhoff and Wimschulte (2009) is that the differences used to vary more often in sign for the particular areas than they appear to do for the new period, 2008-2015. For the maximum and minimum values I observe that the maximum is much larger than the minimum in absolute values. The maximum price difference were particularly large in 2009 and 2010 with area prices exceeding the system price with respectively 189.82 and 370.88 euro for all except two areas. Due to transmission congestion prices will differ between areas, and areas with excess supply will transfer electricity to the areas with excess demand. Electricity may be seen as a necessity, which usually results in an inelastic demand curve for a particular good. Because of this inelastic demand curve the price will only have a small impact on demand. Therefore, in order to reduce demand the price must be increased significantly.

Table 4: Annual mean differences between area prices and system price in absolute and percentage terms, plus some additional descriptive statistics (EUR/MWh)

		ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
2008	Mean (abs.)	11,75	11,93	6,32	-5,59	6,48	6,43	-	-	-
	Mean (%)	26,3%	26,7%	14,1%	-12,5%	14,5%	14,4%	-	-	-
	St.dev.	11,49	11,56	6,87	6,21	6,17	6,78	-	-	-
	Min	-13,49	-10,91	-6,82	-32,94	-1,55	-3,89	-	-	-
	Max	47,59	47,59	31,49	1,28	31,49	31,49	-	-	-
2009	Mean (abs.)	1,02	4,85	1,95	-1,26	0,54	1,98	-	-	-
	Mean (%)	2,9%	13,8%	5,5%	-3,6%	1,5%	5,6%	-	-	-
	St.dev.	4,30	11,63	10,20	2,31	10,24	10,16	-	-	-
	Min	-36,28	-5,41	-9,00	-21,47	-16,19	-9,00	-	-	-
	Max	27,49	189,82	189,82	3,47	189,82	189,82	-	-	-
2010	Mean (abs.)	-6,81	3,65	3,58	1,26	4,99	3,76	-	-	-
	Mean (%)	-12,8%	6,8%	6,7%	2,4%	9,4%	7,1%	-	-	-
	St.dev.	12,02	25,58	23,61	6,13	23,25	23,21	-	-	-
	Min	-95,41	-56,89	-14,15	-44,62	-8,14	-14,15	-	-	-
	Max	10,38	370,88	370,88	46,32	370,88	370,88	-	-	-
2011	Mean (abs.)	1,15	2,59	2,27	-0,68	0,44	0,81	0,65	1,44	0,65
	Mean (%)	2,5%	5,5%	4,8%	-1,5%	0,9%	1,7%	1,4%	3,1%	1,4%
	St.dev.	11,80	12,38	6,07	2,80	1,78	2,33	2,08	3,49	2,08
	Min	-38,63	-38,47	-10,03	-18,62	-4,45	-4,99	-4,99	-4,99	-4,99
	Max	43,97	43,97	32,32	7,37	9,58	14,83	9,58	19,98	9,58
2012	Mean (abs.)	5,23	6,45	5,47	-1,65	0,29	1,14	0,59	3,03	0,53
	Mean (%)	16,8%	20,7%	17,5%	-5,3%	0,9%	3,7%	1,9%	9,7%	1,7%
	St.dev.	9,54	9,35	6,81	2,67	2,28	3,14	2,62	5,41	2,64
	Min	-73,79	-73,74	-1,20	-14,94	-15,73	-5,30	-15,29	-5,30	-15,29
	Max	30,35	31,66	35,90	8,71	16,90	16,90	16,90	25,75	16,90
2013	Mean (abs.)	0,83	1,48	3,06	-0,54	0,87	1,35	1,09	1,84	1,09
	Mean (%)	2,2%	3,9%	8,0%	-1,4%	2,3%	3,5%	2,9%	4,8%	2,9%
	St.dev.	21,70	5,98	5,56	1,81	2,19	3,43	3,08	3,74	3,08
	Min	-33,63	-30,98	-7,38	-6,26	-2,75	-7,38	-7,38	-7,38	-7,38
	Max	396,44	24,62	50,80	5,87	16,06	15,77	15,77	15,77	15,77
2014	Mean (abs.)	1,07	2,55	6,26	-2,27	1,96	2,03	1,84	2,32	1,84
	Mean (%)	3,6%	8,6%	21,2%	-7,7%	6,6%	6,9%	6,2%	7,8%	6,2%
	St.dev.	6,13	4,90	4,52	2,90	2,91	3,37	3,24	3,55	3,24
	Min	-28,11	-16,90	-0.11	-15,92	-5,57	-3,01	-5,57	-3,01	-5,57
	Max	23,58	23,58	25,87	5,75	14,27	23,58	23,58	23,58	23,58
2015	Mean (abs.)	1,85	3,44	8,74	-1,12	0,27	0,99	0,18	1,88	0,16
	Mean (%)	8,8%	16,3%	41,5%	5,3%	1,3%	4,7%	0,9%	8,9%	0,8%
	St.dev.	6,06	6,02	8,49	1,83	2,01	2,93	2,38	3,94	2,35
	Min	-22,08	-14,83	-2,49	-9,33	-15,42	-3,69	-14,15	-2,86	-14,15
	Max	30,98	31,58	51,87	5,00	7,16	22,51	19,68	23,84	19,68

Table 5 shows descriptive statistics for the differences between the area prices and the system price for the whole study period, 2008-2015. Here Copenhagen and Helsinki experienced the largest differences, and Sundsvall and Luelå the smallest differences. Oslo is the only area with an overall negative difference. Based on the values for skewness and kurtosis I know that the observations are not normally distributed. For the areas with the highest numbers of kurtosis I know that the distribution is leptokurtic with fat tails. This means that the observation area is large even though most observations are clustered around the mean, resulting in many extreme observations and large standard deviations. Also, based on the maximum and minimum values, I know that the differences can become very large in either direction.

Table 5: Descriptive statistics for differences between area prices and the system price, 2008-2015

	ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
MEAN	2.01	4.62	4.71	-1.48	1.97	2.31	0.87	2.10	0.85
ST.DEV	12.50	12.90	10.91	4.14	9.66	9.73	2.77	4.12	2.77
SKEW	10.51	11.04	17.20	-0.94	25.03	24.42	2.07	2.19	2.07
KURTOSIS	343.7	266.9	502.5	29.05	842.1	816.1	12.64	8.6	12.64
MINIMUM	-95.4	-73.7	-14.1	-44.6	-16.2	-14.1	-15.3	-7.4	-15.3
MAXIMUM	396.4	370.9	370.9	46.3	370.9	370.9	23.6	25.8	23.6
OBS.	2926	2926	2926	2926	2926	2926	1829	1829	1829

5.4 EPAD prices

Moving to the financial market of EPADs I look at the mean EPAD closing prices in Table 6. Oslo is the only area with mainly negative prices, which was explained by Spodniak et al. (2014) as the result of a majority of hydro producers demanding a hedge against price differences. Their demand is highest in wet years because in these years the electricity price tends to be low. Similar to the differences between area prices and the system price, the EPAD prices show both spatial and temporal price differences. Like Spodniak et al. (2014) I expect the volatility of the areas with large hydro reservoirs to be lower than for the other areas. This includes Oslo, Tromsø, Stockholm, Sundsvall and Luelå, but the theory does not always apply. One thing that seem to be consistent, on the other hand, is that the Danish areas appears to experience largest annual volatility.

Table 6: Annual mean closing prices of EPADs and their standard deviations (in brackets)

	ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
2008	14.10	13.96	6.30	-4.75	-	6.08	-	-	-
	(8.38)	(6.04)	(3.09)	(3.20)		(3.23)			
2009	2.85	5.21	1.89	-1.17	-	2.07	-	-	-
	(1.83)	(3.07)	(1.27)	(0.66)		(1.26)			
2010	-4.66	2.07	1.89	1.15	-	1.85	-	-	-
	(8.99)	(2.88)	(3.55)	(1.47)		(3.63)			
2011	2.40	4.54	3.46	0.02	-0.32	3.38	0.87	12.40	0.29
	(7.75)	(8.33)	(3.27)	(3.00)	(0.41)	(2.90)	(0.52)	(2.66)	(0.49)
2012	7.63	9.27	7.49	-1.94	-0.41	2.47	-0.05	5.59	-0.06
	(4.64)	(4.07)	(3.99)	(1.02)	(0.38)	(1.25)	(0.71)	(1.82)	(0.70)
2013	0.23	2.46	4.04	-0.29	0.33	1.84	0.89	2.27	0.84
	(2.54)	(2.21)	(2.74)	(0.86)	(0.67)	(1.47)	(1.18)	(1.51)	(1.14)
2014	2.24	4.24	7.37	-1.33	1.61	2.74	2.23	3.32	2.23
	(2.99)	(2.15)	(1.95)	(0.86)	(1.42)	(1.67)	(1.66)	(1.45)	(1.68)
2015	2.75	5.13	9.49	-1.87	0.67	1.95	1.24	2.98	1.25
	(3.29)	(2.76)	(3.40)	(0.99)	(0.69)	(0.92)	(1.02)	(0.95)	(1.02)

6 Results and Discussion

The main objective of this thesis is to evaluate the efficiency of EPAD contracts as hedging instruments. In order to evaluate this efficiency I will examine the risk premiums of EPAD contracts. The risk premiums are therefore fundamental in my thesis, and new time series variables for risk premiums of EPAD contracts are obtained through calculations based on equation 9 in chapter 4.2. The four hypotheses presented in chapter 3.5 are tested thoroughly, and in this chapter I will include a presentation and discussion of the results.

6.1 Potential data problems

Before I start looking at the results I will address some potential data problems. First, it is of importance that all variables that are to be included in any regressions are stationary. This is to avoid spurious regressions, and therefore I apply the Augmented Dickey Fuller test to all relevant variables. All lags with coefficients significantly different from zero are included, and the test results are summarized in Table 11 in the appendix. The null hypothesis about unit root is rejected based on the t-value[2], and I conclude that all relevant variables are stationary. Furthermore, the regressions are tested for heteroscedasticity using the Breusch-Pagan test, and for serial correlation using the Breusch-Godfrey test. The test results are presented in Table 12 and Table 13 in the appendix, and I find that most of the regressions suffer from both heteroscedasticity and serial correlation. Because of these problems I will use the Newey West estimator on all regressions in order to obtain HAC standard errors, which are robust against heteroscedasticity and serial correlation.

6.2 Hypothesis I

Hypothesis I: there is no significant difference between the area prices and the system price over time.

Before I start looking at the risk premiums I will consider the price difference between the area prices and the system price. The EPAD contracts are created based on the fact that there exists a basis risk, meaning a price difference between an area price and the system price. However, if this difference is not significantly different from zero there will be no need for EPAD contracts in the first place. I will therefore investigate the significance and magnitude of the price differences for each year separately, as well as for the whole period. Table 7 lists

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[2] The critical t-value for the ADF test used at the 5% significance level is -2,86.

the same mean values for the price differences as Table 4 did, but instead of descriptive statistics Table 7 includes HAC standard errors. I regressed the different price differences against their annual mean values using the Newey-West estimator to obtain these HAC standard errors, and I included a lag length of 7 in order to capture any weekly effects in the time series. The HAC standard errors help me decide the significance of the price differences. I will use the 95% significance level throughout this chapter, and reject the null hypothesis whenever the t-value[3] exceeds the critical t-value[4] in absolute terms. For the overall period, 2008-2015, all differences are significantly different from zero. The overall largest difference are found in Copenhagen and Helsinki, and the only negative difference is found in Oslo. By looking at the annual mean values I find that 51 of 63 observations are significantly different from zero, resulting in 19% of the observations being insignificant. However, there seem to be no clear pattern as to which areas prove to have significant or insignificant mean values since they vary between years. Based on these observations I reject *hypothesis I* and conclude that the differences are significantly different from zero over time, and that EPADs are needed.

Table 7: Annual mean differences between area prices and the system price, and their HAC standard errors (in brackets)

	ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
2008-2015	1.617 (0.423)	4.199 (0.390)	3.989 (0.297)	-1.340 (0.161)	1.784 (0.240)	2.034 (0.242)	0.866 (0.148)	2.098 (0.204)	0.852 (0.148)
2008	11.746 (1.418)	11.928 (1.427)	6.324 (0.931)	-5.589 (0.796)	6.484 (0.840)	6.425 (0.921)	-	-	-
2009	1.016 (0.384)	4.848 (0.917)	1.950 (0.670)	-1.263 (0.262)	0.542 (0.678)	1.979 (0.664)	-	-	-
2010	-6.81 (1.541)	3.654 (1.906)	3.577 (1.744)	1.256 (0.657)	4.987 (1.765)	3.757 (1.723)	-	-	-
2011	1.148 (1.603)	2.594 (1.671)	2.265 (0.782)	-0.677 (0.344)	0.440 (0.202)	0.806 (0.248)	0.648 (0.228)	1.436 (0.414)	0.648 (0.228)
2012	5.234 (1.052)	6.448 (1.002)	5.470 (0.775)	-1.649 (0.297)	0.286 (0.205)	1.136 (0.315)	0.592 (0.253)	3.030 (0.583)	0.531 (0.258)
2013	0.833 (1.273)	1.481 (0.606)	3.058 (0.607)	-0.537 (0.223)	0.865 (0.253)	1.354 (0.424)	1.095 (0.389)	1.836 (0.436)	1.095 (0.389)
2014	1.066 (0.627)	2.545 (0.534)	6.263 (0.454)	-2.268 (0.362)	1.957 (0.391)	2.027 (0.439)	1.835 (0.434)	2.320 (0.433)	1.835 (0.434)
2015	1.853 (0.591)	3.443 (0.620)	8.744 (0.872)	-1.120 (0.203)	0.271 (0.196)	0.999 (0.241)	0.177 (0.239)	1.884 (0.346)	0.165 (0.235)

HAC standard errors are used in this table due to heteroscedasticity and serial correlation.

[3] The t-value is found by dividing the mean value on the standard error.
[4] The critical t-value at the 5% significance level is ±1.96.

6.3 Hypothesis II

Hypothesis II: there is no significant ex-post risk premium in the EPAD market.

Here I am interested in the significance and the magnitude of the risk premiums, and to test *hypothesis II* I regress the risk premiums against their annual mean values. Again I use the Newey-West estimator, with 7 lags included, to obtain HAC standard errors. Theoretically I expect the risk premiums to be positive, meaning that consumers pay a premium to generators or speculators in order to hedge their basis risk. This is because I believe generators have dominant market power for contracts with shorter delivery periods, meaning that the hedging pressure is largest among consumers for month contracts. However, the risk premium is not observable until after the delivery period as it depends on the average price difference during the delivery period, and may therefore be hard to predict and interpret.

Table 8 presents the annual mean values of the risk premiums and their HAC standard errors. For the whole period I find that 40 out of 60 observations are significantly different from zero on a 95% significance level. I also find that 32 out of 40 significant observations are positive in sign. I observe no clear trends in the table as the sign and magnitude of the risk premiums appear to be random. However, it looks like risk premiums are more likely to be significant after 2011 than before, and in 2015 I only observe one insignificant risk premium which applies to Helsinki. Tromsø has mostly negative risk premiums, and in 2010 most areas also showed negative risk premiums. Kristiansen attributed positive risk premiums to situations with predominance of risk-averse consumers who were willing to pay a premium to hedge against possible price spikes. The negative values, however, he attributed to situations predominated by risk-averse generators wishing to hedge their production. (Kristiansen, 2004b).

Wind and hydro power depend on varying weather conditions, and therefore the flow of electricity between areas might change direction over time. Therefore transmission congestion varies widely over time and between areas, which again causes the sign and magnitude of the risk premium to also vary both spatially and temporally. I conclude that the risk premiums are significantly different from zero for most areas and years, but that it is hard to observe trends and to establish rules based on these results.

Marckhoff and Wimschulte (2009) observed mostly significant risk premiums for quarter, season and year contracts for the years 2001-2006. Month contracts were first introduced in

2004, but these also seem to include a significant risk premium. One interesting finding in the study of Marckhoff and Wimschulte (2009) is that the contracts for Oslo appears to have an opposite sign compared to the sign of the majority. This trend is not apparent in my results since the sign for Oslo is mostly the same as for the other areas. Beyond this, there is little evidence to suggest other trends in the risk premiums in the study of Marckhoff and Wimschulte (2009). This is in line with my findings, and suggests that the risk premiums are mostly random.

Table 8: Annual mean ex-post risk premiums of EPADs (EUR/MWh)

	ARH	CPH	HEL	OSL	TRO	STO	SND	MAL	LUL
2008	2.352	2.061	-0.030	0.832	-	-0.348	-	-	-
	(0.688)	(0.820)	(0.480)	(0.357)		(0.463)			
2009	1.894	0.236	-0.142	0.123	-	0.006	-	-	-
	(0.226)	(0.482)	(0.322)	(0.150)		(0.321)			
2010	1.937	-1.635	-1.603	-0.093	-	-1.817	-	-	-
	(0.617)	(0.905)	(0.897)	(0.337)		(0.884)			
2011	1.395	2.086	1.190	0.667	-1.111	2.568	-0.528	8.671	-1.102
	(0.591)	(0.615)	(0.356)	(0.228)	(0.307)	(0.294)	(0.393)	(1.014)	(0.470)
2012	2.443	2.859	2.036	-0.294	-0.695	1.340	-0.643	2.568	-0.594
	(0.442)	(467)	(0.623)	(0.224)	(0.161)	(0.239)	(0.152)	(0.230)	(0.154)
2013	-0.660	0.955	0.984	0.244	-0.529	0.492	-0.207	0.444	-0.256
	(0.489)	(0.337)	(0.321)	(0.158)	(0.170)	(0.249)	(0.224)	(0.234)	(0.228)
2014	1.173	1.708	0.964	0.950	-0.320	0.724	0.413	1.015	0.411
	(0.323)	(0.325)	(0.271)	(0.237)	(0.232)	(0.342	(0.302)	(0.330)	(0.302)
2015	0.903	1.669	0.872	-0.762	0.382	0.939	1.051	1.08	1.070
	(0.417)	(0.405)	(0.483)	(0.154)	(0.143)	(0.235)	(0.202)	(0.303)	(0.198)

HAC standard errors are used in this table due to heteroscedasticity and serial correlation.

6.4 Hypothesis III

Hypothesis III: there are no changes in risk premium over time to maturity.

Next I will take *hypothesis III* into consideration as I analyze how the risk premiums of the front contracts behave over the remaining time to maturity. In order to explore this hypothesis I conduct the regression from equation 11 in chapter 4.2. The results from this regression is summarized in Table 9[5]. The test results for the Breusch-Pagan and Breusch-Godfrey tests

[5] HAC standard errors are obtained by using the Newey-West estimator with 7 lags.

can be found in Table 12 and Table 13 in the appendix, and these tests suggest that I have a problem with heteroscedasticity and serial correlation. The positive significant constant, *C*, indicates that the risk premium is mostly positive for these contracts, except from Tromsø which display a negative significant constant. Table 9 coincides with Table 8 in that the risk premiums are mainly positive. The coefficients on time-to-maturity, however, show more variation in sign, but none of these are actually significant. Also, based on the close-to-zero adjusted R-squared, the model has poor predictive power. Therefore, I will not put too much trust on these results, but it might still be interesting to compare the results to those of Marckhoff and Wimschulte (2009).

Marckhoff and Wimschulte (2009) points out that market participants hedging behavior depend on their degree of risk aversion and their planning horizon. Generators are exposed to uncertainty regarding their future revenues, making them more eager to hedge their risk long-term. Consumers, on the other hand, typically make more short-term hedges to secure themselves against possible price spikes. Therefore, consumers are said to have market power for longer horizons, like year contracts, while generators are said to have market power for shorter horizons, like quarter and month contracts. Marckhoff and Wimschulte (2009) found that forwards followed this pattern as year contracts tended to have a negative constant while the quarter and month contracts tended to have positive constants. Also they found that the risk premium for year and quarter contracts was increasing over time to maturity as the coefficient on time-to-maturity was negative.

The results for the EPAD contracts are not as clear cut as the results for forwards in the study of Marckhoff and Wimschulte (2009). According to them the constants are mostly positive and significant for all maturities, which also coincides with my own findings. The coefficients on time-to-maturity, however, are somewhat ambiguous since they vary in both sign and magnitude between areas and over delivery periods. Marckhoff and Wimschulte (2009) found that the coefficients on time-to-maturity for year and quarter contracts were mostly significant while the coefficients on time-to-maturity for month contracts were mostly insignificant. This might be due to the immaturity of month contracts since they first started trading in 2004, but may also be due to the limited time to maturity since they are only traded over a two-month period. I believe the limited trading period prevents the creation of clear trends, and therefore it is easier to observe significant coefficients on time-to-maturity for year and quarter contracts than for month contracts. My coefficients on time-to-maturity for month contracts are in line with those of Marckhoff and Wimschulte. This is also what I would expect as I only look at the front contract for each area, resulting in an even shorter trading period of maximum 31 days. Based on the regression results I cannot reject *hypothesis III*, and therefore I conclude that there are no clear changes in risk premium over time to maturity.

Table 9: Regression of ex-post risk premium on time-to-maturity, 2008-2015.

AREA	*C*	*B*	ADJ. R^2
ÅRHUS (DK1)	1.3682 (0.3591)	0.0109 (0.0189)	0.0006
COPENHAGEN (DK2)	1.3682 (0.3439)	-0.0003 (0.0187)	-0.0003
HELSINKI (HEL)	0.6551 (0.3132)	-0.0037 (0.0177)	-0.0003
OSLO (OSL)	0.2412 (0.1369)	0.0029 (0.0079)	-0.0001
TROMSØ (TRD)	-0.3384 (0.1711)	-0.0008 (0.0092)	-0.0006
STOCKHOLM (SE3)	0.4240 (0.2223)	-0.0020 (0.0126)	-0.0002
LUELÅ (SE1)	0.0099 (0.2120)	0.0034 (0.0119)	-0.0003
MALMÖ (SE4)	1.4853 (0.3526)	0.0230 (0.0204)	0.0035
SUNDSVALL (SE2)	0.0441 (0.2071)	0.0038 (0.0116)	-0.0003

HAC standard errors are used in this table due to heteroscedasticity and serial correlation.

6.5 Hypothesis IV

Hypothesis IV: variance and skewness of the area and system prices cannot be classified as determinants of risk premium.

In addition to the significance of the risk premium and the development of the risk premium over time to maturity, Marckhoff and Wimschulte (2009) were also interested in the determinants of the risk premium. They argue that it is essential to understand the different determinants of risk premiums in order for proper risk management. Marckhoff and Wimschulte (2009) looked at the variance and skewness of the area and system prices as possible determinants of risk premiums, and therefore I will conduct a similar analysis. Variance and skewness are calculated as moving averages over 28 days, and are based on daily area and system prices. The area prices are aggregated to form a new variable which contains the daily average area prices. By aggregating over areas I obtain a larger sample size and more robust results, and this was also done by Marckhoff and Wimschulte (2009). I conduct the regression from equation 12 in chapter 4.2 and present the results in Table 10 with HAC standard errors[6]. The test results for the Breusch-Pagan and Breusch-Godfrey tests

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[6] HAC standard errors are obtained by using the Newey-West estimator with 7 lags.

can be found in Table 12 and Table 13 in the appendix, and these tests suggest that I have a problem with heteroscedasticity and serial correlation. The constant, *C*, suggests an overall positive risk premium, which is consistent with my previous findings.

The theoretical signs of the variance and skewness coefficients are based on the fact that EPADs imply a long position in a hypothetical area forward contract and a short position in a system forward contract. Marckhoff and Wimschulte (2009) expected the variance of the system price to have a positive effect and the skewness of the system price to have a negative effect on the risk premium of the EPADs. For the area price they expected the opposite signs compared to the system price. Marckhoff and Wimschulte (2009) found that area variance was positive and significant, the system variance was insignificant, the area skewness was negative and significant, and that the system skewness was negative and significant. They expected the area variance to have a negative effect and the area skewness to have a positive effect on risk premiums in EPADs. They were wrong for both coefficients for month contracts, but the contracts for season and year displayed the expected signs. My results suggests that both area variance and area skewness have a negative impact on the risk premiums, and these coefficients are both significantly different from zero. Further, Marckhoff and Wimschulte (2009) expected the system variance to have a positive effect and the system skewness to have a negative effect on EPAD risk premiums. They found the system variance insignificant for month contracts, but positive and significant for both year and season. The system skewness was in line with their expectations for both year, season and month contracts. My results suggests that both system variance and system skewness have a positive impact on the risk premiums, but it is only the system skewness that is significant and thus has explanatory power.

The adjusted R-squared tells me that included variables explain about 28% of the variation in the risk premium, while Marckhoff and Wimschulte (2009) found this number to be 38% for the month contract. However, the adjusted R-squared measure penalizes additional observations, and I believe that is why my value is lower than that of Marckhoff and Wimschulte. Moreover, none of the adjusted R-squared values for month contracts are large, and I would say that both models has poor predictive power and that they lack some essential explanatory variables. Marckhoff and Wimschulte (2009) found that the adjusted R-squares for season and year contracts to be respectively 77% and 69%, and compared to these values the model for month contracts is not good at all.

To sum up, Marckhoff and Wimschulte (2009) found that the coefficient on system skewness was in line with their expectations, while I found that the coefficient on area variance was in line with the expectations. For the month contract Marckhoff and Wimschulte (2009) only had data covering 2004-2006, which may have been too few observations. However, my data covered eight years, 2008-2015, and I still did not get more significant results. Based on these regression results I would not classify variance and skewness of area and system prices as determinants of risk premium and therefore *hypothesis IV* still stands.

Table 10: Regression of ex-post risk premium on variance and skewness of area and system prices, 2008-2015.

EPAD	C	α_1	α_2	γ_1	γ_2	**ADJ** R^2
MONTH CONTRACT	0.9450 (0.0860)	-0.0035 (0.0008)	0.0028 (0.0023)	-0.3055 (0.1197)	0.4916 (0.0965)	0.281
EXPECTATIONS		< 0	> 0	> 0	< 0	

HAC standard errors are used in this table due to heteroscedasticity and serial correlation.

6.6 Discussion

The results of my analysis suggests that the demand for EPADs is justified since the difference between the area prices and the system price is significantly different from zero. Furthermore, the EPAD contracts mostly display positive significant risk premiums, and this conclusion is based on both Table 8, Table 9, and Table 10. I could not confirm that the time to maturity, nor the variance and skewness of the area and system prices were determinants of risk premiums. These determinants might be more apparent for the year and quarter contracts with longer trading periods, which means that there are other determinants of risk premiums that apply in the short run.

The analysis in this thesis is limited to the study period 2008-2015 and only includes monthly EPAD contracts. These monthly EPAD contracts has a maximum trading period of 31 days since I only focused on the front contract, whereas the actual trading period is maximum 61 days. This limitation might have affected the results for *hypothesis III* where I looked at the changes in risk premium over time to maturity. EPAD contracts for quarters and years might also have shown different results as both their trading and delivery periods are much longer. However, the quarterly and yearly contracts are believed to be less liquid than the monthly contracts. The EPAD market has previously struggled with low liquidity resulting in few trades and questions about market efficiency. This may still be a problem, but the inclusion of market makers has eased this issue as they will quote bid and ask prices whenever necessary.

Regardless, low liquidity may result in EPAD prices that does not properly reflect all available information, which again leads to an inefficient market. I believe that the monthly EPAD contracts faces sufficient liquidity, but I cannot draw any conclusions for the quarterly and yearly contracts as I have not studied these. Another limitation to this thesis is that the monthly contracts first started trading in 2004, even though the EPAD market opened in 2000. This means that the market for monthly EPAD contracts may not be as established as the market for quarter and year contracts. I can only speculate in whether or not the market for monthly EPAD contracts is well established or if it will show different results in the future.

As mentioned before the risk premiums are calculated ex-post, meaning that their size depend on the price difference between the area price and the system price during the delivery period. The factors that drives this price difference will therefore also be determinants of risk premiums. As mentioned in chapter 2.2 hydropower constituted 60% of all power production in 2015, and the hydropower production is highly dependent on the weather. The power supply is therefore strongly linked to weather conditions. An area short on supply will import from neighboring areas, which may result in capacity constraints on transmission lines being violated. The areas which lack supply will experience higher prices than the system price, and the areas with excess supply will experience lower prices than the system price. Additionally, the elasticity of demand for electricity is known to be inelastic, resulting in small transmission congestions causing large price changes between areas. Therefore, I believe that the weather conditions during the delivery period is one of the main determinants of risk premiums for EPAD contracts, both monthly, quarterly and yearly.

6.7 Further research

I have looked at whether or not the monthly EPAD contracts can be classified as efficient. It is also interesting to look at the contracts for quarters and years over a more recent time period. It could be that the risk premiums for these longer-termed contracts prove to be more significant, and that the regressions show stronger relationships. Further, it would be interesting to explore other possible determinants of risk premiums in the short run. I mentioned weather conditions in the previous chapter, but also factors like transmission congestion, trading pattern, open interest, and the risk premiums of Futures and DS Futures contracts may prove interesting. Marckhoff and Wimschulte (2009) and Spodniak et al. (2014) additionally looked at the difference between area and system prices compared to the relative reservoir levels in Norway, Sweden and Finland and found a clear relationship. I believe their conclusion is applicable also today, but it is still interesting to study this relationship for a different time period.

7 Conclusion

The purpose of this thesis has been to investigate the efficiency of monthly EPAD contracts by applying the methods used by Marckhoff and Wimschulte (2009) to a more recent time period. I suspected the study period of Marckhoff and Wimschulte, 2001-2006, to show unsure results due to the immaturity of the EPAD market. Their study included the first six years of trading for quarterly and yearly contracts, and the two first years of trading for the monthly contract. It is therefore interesting to look at the more recent time period, 2008-2015, in order to decide whether or not the market efficiency has changed as the market has become more established.

Four different hypotheses have now been tested. First, I conclude that there is a significant difference between the area prices and the system price, therefore I assert that the basis risk is an actual risk faced by market participants which justifies the demand for EPAD contracts. Second, I observe risk premiums that are mostly positive and significantly different from zero. However, there are substantial variations in sign and magnitude both spatially and temporally. For the third hypothesis I conclude that there are no clear changes in risk premium over time to maturity. However, the positive and significant constants coincides with the rejection of *hypothesis II*, suggesting on average positive risk premiums. Finally, I cannot find a relationship between the risk premiums and the variance and skewness of the area and system prices, therefore these variables are not determinants of risk premiums for monthly contracts. However, the significant positive constant again suggests an overall positive risk premium, which is in line with both conclusions in *hypothesis II* and *hypothesis III*.

Based on the study of Marckhoff and Wimschulte (2009) I expected to find significant risk premiums, and that is also what I found. However, I find it hard to draw a conclusion to my overall research question solely based on these significant risk premiums. To make it easier I additionally consider the substantial variation in sign and magnitude between areas and over time. This variation may very well be the strongest sign of market efficiency I have access to. The area and system prices will vary during the delivery period based on factors like weather conditions and transmission congestion, and EPAD prices will vary based on expectations of future prices. These prices affect the risk premium directly. According to the efficient market hypothesis the risk premium should reflect available market information, and the fact that it varies substantially might suggest that it responds well to outside determinants. On the other hand, if the variations prove to be noise I cannot say that the market is efficient. In order for me to conclude on the efficiency of the EPAD market I must therefore determine whether or not the variation in risk premium is random.

So, are monthly electricity price area differentials (EPADs) efficient hedging instruments against the basis risk in the Nordic energy market?

EPADs should provide a good hedge against the basis risk, and based on the positive significant, and varying, risk premiums I believe they are efficient hedging instruments. However, I would like for the variations in risk premiums to be further investigated to decide whether or not the variation is random or if it is determined by underlying variables. Therefore, I am inconclusive about the overall research question as I believe there are still unanswered questions.

8 Reference List

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9 Appendix

9.1 Data description

variable name	storage type	display format	value label	variable label
price_sys	double	%10.0g		**System price (EUR/MWh)**
price_arh	double	%10.0g		**ARH location price (EUR/MWh)**
price_cph	double	%10.0g		**CPH location price (EUR/MWh)**
price_hel	double	%10.0g		**HEL location price (EUR/MWh)**
price_lul	double	%10.0g		**LUL location price (EUR/MWh)**
price_mal	double	%10.0g		**MAL location price (EUR/MWh)**
price_osl	double	%10.0g		**OSL location price (EUR/MWh)**
price_sto	double	%10.0g		**STO location price (EUR/MWh)**
price_snd	double	%10.0g		**SND location price (EUR/MWh)**
price_trd	double	%10.0g		**TRD location price (EUR/MWh)**
price_aggr	double	%10.0g		**Aggregated location price (EUR/MWh)**
price_sys	double	%10.0g		**System price (EUR/MWh)**
var_sys	double	%10.0g		**Variance of system price**
skew_sys	double	%10.0g		**Skewness of system price**
trd_sys	double	%10.0g		**Price difference between TRD and SYS**
snd_sys	double	%10.0g		**Price difference between SND and SYS**
lul_sys	double	%10.0g		**Price difference between LUL and SYS**
mal_sys	double	%10.0g		**Price difference between MAL and SYS**
sto_sys	double	%10.0g		**Price difference between STO and SYS**
hel_sys	double	%10.0g		**Price difference between HEL and SYS**
osl_sys	double	%10.0g		**Price difference between OSL and SYS**
cph_sys	double	%10.0g		**Price difference between CPH and SYS**
arh_sys	double	%10.0g		**Price difference between ARH and SYS**
cprice_arh	double	%10.0g		**ARH EPAD closing price**
cprice_cph	double	%10.0g		**CPH EPAD closing price**
cprice_hel	double	%10.0g		**HEL EPAD closing price**
cprice_lul	double	%10.0g		**LUL EPAD closing price**
cprice_mal	double	%10.0g		**MAL EPAD closing price**
cprice_osl	double	%10.0g		**OSL EPAD closing price**
cprice_sto	double	%10.0g		**STO EPAD closing price**
cprice_sun	double	%10.0g		**SND EPAD closing price**
cprice_trd	double	%10.0g		**TRD EPAD closing price**
rp_snd	double	%10.0g		**SND Risk premium**
rp_mal	double	%10.0g		**MAL Risk premium**
rp_lul	double	%10.0g		**LUL Risk premium**
rp_sto	double	%10.0g		**STO Risk premium**
rp_trd	double	%10.0g		**TRD Risk premium**
rp_osl	double	%10.0g		**OSL Risk premium**
rp_hel	double	%10.0g		**HEL Risk premium**
rp_cph	double	%10.0g		**CPH Risk premium**
rp_arh	double	%10.0g		**ARH Risk premium**
rp_aggr	double	%10.0g		**Aggregated Risk Premium**
ttm	byte	%10.0g		**Time to maturity**

9.2 Data summary

Variable	Obs	Mean	Std. Dev.	Min	Max
price_sys	3,654	37.60961	14.2286	3.88	134.8
price_arh	3,654	39.22688	15.32684	-38.42875	436.3258
price_cph	3,654	41.80868	18.42098	-38.38208	505.6812
price_hel	3,654	41.58812	17.08798	6.300833	505.6812
price_lul	1,829	34.2098	13.08689	3.510417	99.60833
price_mal	1,829	35.45651	13.28585	3.510417	101.2588
price_osl	3,654	36.26963	15.56819	2.069583	151.675
price_sto	3,654	39.64321	17.93579	3.510417	505.6812
price_snd	1,829	34.22432	13.08294	3.510417	99.60833
price_trd	3,654	39.39362	18.07817	4.097917	505.6812
price_aggr	3,654	39.55622	15.52359	4.109352	368.9652
price_sys	3,654	37.60961	14.2286	3.88	134.8
var_sys	3,653	27.14163	44.85594	.2799766	359.4076
skew_sys	3,652	.006608	.9858971	-3.423655	3.619736
trd_sys	3,654	1.784016	8.743589	-16.19333	370.8812
snd_sys	1,829	.8662576	2.76885	-15.29458	23.58417
lul_sys	1,829	.8517396	2.770435	-15.29458	23.58417
mal_sys	1,829	2.09845	4.119502	-7.379166	25.75
sto_sys	3,654	2.033599	8.864157	-15.1825	370.8812
hel_sys	3,654	3.978506	10.08664	-15.1825	370.8812
osl_sys	3,654	-1.339982	4.030283	-44.61833	46.32124
cph_sys	3,654	4.199068	12.30129	-73.74208	370.8812
arh_sys	3,654	1.617273	12.33871	-95.40875	396.4359
cprice_arh	2,986	3.516674	7.609406	-40	42.13
cprice_cph	3,654	5.562548	5.50327	-12.83	40.1
cprice_hel	2,986	5.186979	3.99483	-4.5	18.7
cprice_lul	1,586	1.005378	1.40955	-1.98	7.5
cprice_mal	1,586	4.22826	3.091952	-.1	17
cprice_osl	3,654	-1.051814	2.322994	-15	10.5
cprice_sto	3,654	2.424962	2.53688	-5.25	13.6
cprice_sun	1,586	1.062371	1.397105	-1.95	7.3
cprice_trd	1,586	.4863619	1.123408	-1.25	6
rp_snd	1,586	.1044863	1.736452	-5.827917	4.072625
rp_mal	1,586	1.849392	3.154293	-5.505889	14.41414
rp_lul	1,586	.0642362	1.780766	-5.877916	4.072625
rp_sto	3,654	.3913631	3.060386	-23.31701	11.86871
rp_trd	1,586	-.3514345	1.357751	-4.34775	2.48035
rp_osl	3,654	.2881678	1.839422	-10.95024	9.67379
rp_hel	2,986	.5967653	3.760528	-23.37726	18.72608
rp_cph	3,654	1.36348	4.246953	-22.58994	13.42301
rp_arh	2,986	1.539987	3.806994	-14.52573	21.97427
rp_aggr	3,654	.6986253	2.047343	-15.50604	5.845062
ttm	3,654	15.73536	8.804024	1	31

9.3 Tests

9.3.1 Augmented Dickey Fuller test

Table 11: Augmented Dickey Fuller test results

VARIABLE	LABEL	LAG	T-VALUE
RP_ARH	Risk premium Århus	1	-9.063
RP_CPH	Risk premium Copenhagen	1	-8.518
RP_HEL	Risk premium Helsinki	1	-7.064
RP_OSL	Risk premium Oslo	2	-8.948
RP_TRD	Risk premium Tromsø	1	-5.472
PR_STO	Risk premium Stockholm	1	-7.407
RP_SND	Risk premium Sundsvall	1	-5.159
RP_MAL	Risk premium Malmö	1	-4.885
RP_LUL	Risk premium Luelå	1	-5.074
RP_AGGR	Aggregated risk premium	1	-8.364
TTM	Time to maturity	26	-31.663
SKEW_SYS	Skewness of the system price	1	-8.638
VAR_SYS	Variance of the system price	3	-7.357
SKEW_AREA	Skewness of the aggregated area prices	1	-7.767
VAR_AREA	Variance of the aggregated area prices	1	-7.465
ARH_SYS	Price difference between and Århus and Sys.	13	-6.515
CPH_SYS	Price difference between and Copenhagen and Sys.	13	-8.170
HEL_SYS	Price difference between and Helsinki and Sys.	13	-8.948
OSL_SYS	Price difference between and Oslo and Sys.	14	-6.050
TRD_SYS	Price difference between and Tromsø and Sys.	6	-14.039
STO_SYS	Price difference between and Stockholm and Sys.	12	-10.362
SND_SYS	Price difference between and Sundsvall and Sys.	6	-5.769
MAL_SYS	Price difference between and Malmö and Sys.	6	-6.192
LUL_SYS	Price difference between and Luelå and Sys.	6	-5.791

9.3.2 Breusch-Godfrey test for serial correlation

Table 12: Breusch-Godfrey test results

REGRESSION	LAGS	Chi^2
RISK PREMIUM ARH AGAINTS TIME TO MAT.	7	2689.74
RISK PREMIUM CPH AGAINTS TIME TO MAT.	7	3384.73
RISK PREMIUM HEL AGAINTS TIME TO MAT.	7	2786.66
RISK PREMIUM OSL AGAINTS TIME TO MAT.	7	3318.43
RISK PREMIUM TRO AGAINTS TIME TO MAT.	7	1458.16
RISK PREMIUM STO AGAINTS TIME TO MAT.	7	3451.38
RISK PREMIUM LUL AGAINTS TIME TO MAT.	7	1478.03
RISK PREMIUM MAL AGAINTS TIME TO MAT.	7	1509.80
RISK PREMIUM SND AGAINTS TIME TO MAT.	7	1468.23
RISK PREMIUM AGAINST VARIANCE AND SKEWNESS	7	3241.53

9.3.3 Breusch-Pagan test for homoskedasticity

Table 13: Breusch-Pagan test results

REGRESSION	Chi^2
RISK PREMIUM ARH AGAINTS TIME TO MAT.	3.96
RISK PREMIUM CPH AGAINTS TIME TO MAT.	2.28
RISK PREMIUM HEL AGAINTS TIME TO MAT.	31.38
RISK PREMIUM OSL AGAINTS TIME TO MAT.	51.92
RISK PREMIUM TRO AGAINTS TIME TO MAT.	0.07
RISK PREMIUM STO AGAINTS TIME TO MAT.	53.32
RISK PREMIUM LUL AGAINTS TIME TO MAT.	8.43
RISK PREMIUM MAL AGAINTS TIME TO MAT.	25.73
RISK PREMIUM SND AGAINTS TIME TO MAT.	9.16
RISK PREMIUM AGAINST VARIANCE AND SKEWNESS	1089.93

9.4 STATA commands

```
*** Summarize by year and for the overall period ***
sum price_* if year==2006
sum price_* if year==2007
sum price_* if year==2008
sum price_* if year==2009
sum price_* if year==2010
sum price_* if year==2011
sum price_* if year==2012
sum price_* if year==2013
sum price_* if year==2014
sum price_* if year==2015

sum cprice_* if year==2006
sum cprice_* if year==2007
sum cprice_* if year==2008
sum cprice_* if year==2009
sum cprice_* if year==2010
sum cprice_* if year==2011
sum cprice_* if year==2012
sum cprice_* if year==2013
sum cprice_* if year==2014
sum cprice_* if year==2015

sum *_sys if year==2006
sum *_sys if year==2007
sum *_sys if year==2008
sum *_sys if year==2009
sum *_sys if year==2010
sum *_sys if year==2011
sum *_sys if year==2012
sum *_sys if year==2013
sum *_sys if year==2014
sum *_sys if year==2015

sum rp_* if year==2006
sum rp_* if year==2007
sum rp_* if year==2008
sum rp_* if year==2009
sum rp_* if year==2010
sum rp_* if year==2011
sum rp_* if year==2012
sum rp_* if year==2013
sum rp_* if year==2014
sum rp_* if year==2015

sum price* if tin(31.12.2007,03.01.2016), detail
sum *_sys if tin(31.12.2007,03.01.2016), detail

sum price_* *_sys cprice_* rp_* ttm


*** Count if the differences between area and system price is zero ***
count if arh_sys==0
count if cph_sys==0
count if hel_sys==0
count if osl_sys==0
count if trd_sys==0
```

```
count if sto_sys==0
count if lul_sys==0
count if mal_sys==0
count if snd_sys==0

*** Augmented Dickey Fuller test for unit root ***
dfuller rp_arh, lags (1) regress
dfuller rp_cph, lags (1) regress
dfuller rp_hel, lags (1) regress
dfuller rp_osl, lags (2) regress
dfuller rp_trd, lags (1) regress
dfuller rp_sto, lags (1) regress
dfuller rp_snd, lags (1) regress
dfuller rp_mal, lags (1) regress
dfuller rp_lul, lags (1) regress
dfuller rp_aggr, lags (1) regress
dfuller ttm, lags (27) regress
dfuller skew_sys, lags (1) regress
dfuller var_sys, lags (3) regress
dfuller skew_area, lags (1) regress
dfuller var_area, lags (1) regress
dfuller arh_sys, lags(13) regress
dfuller cph_sys, lags(13) regress
dfuller hel_sys, lags(13) regress
dfuller osl_sys, lags(14) regress
dfuller trd_sys, lags(6) regress
dfuller sto_sys, lags(12) regress
dfuller snd_sys, lags(6) regress
dfuller mal_sys, lags(6) regress
dfuller lul_sys, lags(6) regress

*** Newey-West regression of risk premium against mean by area and year ***
reg rp_arh if year==2008
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2008, lag(7)
reg rp_cph if year==2008
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2008, lag(7)
reg rp_hel if year==2008
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2008, lag(7)
reg rp_osl if year==2008
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2008, lag(7)
reg rp_sto if year==2008
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2008, lag(7)

reg rp_arh if year==2009
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2009, lag(7)
reg rp_cph if year==2009
hettest
estat bgodfrey, lags(7)
```

```
newey rp_cph if year==2009, lag(7)
reg rp_hel if year==2009
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2009, lag(7)
reg rp_osl if year==2009
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2009, lag(7)
reg rp_sto if year==2009
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2009, lag(7)

reg rp_arh if year==2010
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2010, lag(7)
reg rp_cph if year==2010
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2010, lag(7)
reg rp_hel if year==2010
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2010, lag(7)
reg rp_osl if year==2010
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2010, lag(7)
reg rp_sto if year==2010
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2010, lag(7)

reg rp_arh if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2011, lag(7)
reg rp_cph if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2011, lag(7)
reg rp_hel if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2011, lag(7)
reg rp_osl if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2011, lag(7)
reg rp_trd if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_trd if year==2011, lag(7)
reg rp_sto if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2011, lag(7)
reg rp_snd if year==2011
```

```
hettest
estat bgodfrey, lags(7)
newey rp_snd if year==2011, lag(7)
reg rp_mal if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_mal if year==2011, lag(7)
reg rp_lul if year==2011
hettest
estat bgodfrey, lags(7)
newey rp_lul if year==2011, lag(7)

reg rp_arh if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2012, lag(7)
reg rp_cph if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2012, lag(7)
reg rp_hel if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2012, lag(7)
reg rp_osl if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2012, lag(7)
reg rp_trd if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_trd if year==2012, lag(7)
reg rp_sto if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2012, lag(7)
reg rp_snd if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_snd if year==2012, lag(7)
reg rp_mal if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_mal if year==2012, lag(7)
reg rp_lul if year==2012
hettest
estat bgodfrey, lags(7)
newey rp_lul if year==2012, lag(7)

reg rp_arh if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2013, lag(7)
reg rp_cph if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2013, lag(7)
reg rp_hel if year==2013
hettest
estat bgodfrey, lags(7)
```

```
newey rp_hel if year==2013, lag(7)
reg rp_osl if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2013, lag(7)
reg rp_trd if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_trd if year==2013, lag(7)
reg rp_sto if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2013, lag(7)
reg rp_snd if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_snd if year==2013, lag(7)
reg rp_mal if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_mal if year==2013, lag(7)
reg rp_lul if year==2013
hettest
estat bgodfrey, lags(7)
newey rp_lul if year==2013, lag(7)

reg rp_arh if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2014, lag(7)
reg rp_cph if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2014, lag(7)
reg rp_hel if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2014, lag(7)
reg rp_osl if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2014, lag(7)
reg rp_trd if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_trd if year==2014, lag(7)
reg rp_sto if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2014, lag(7)
reg rp_snd if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_snd if year==2014, lag(7)
reg rp_mal if year==2014
hettest
estat bgodfrey, lags(7)
newey rp_mal if year==2014, lag(7)
reg rp_lul if year==2014
hettest
```

```
estat bgodfrey, lags(7)
newey rp_lul if year==2014, lag(7)

reg rp_arh if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_arh if year==2015, lag(7)
reg rp_cph if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_cph if year==2015, lag(7)
reg rp_hel if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_hel if year==2015, lag(7)
reg rp_osl if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_osl if year==2015, lag(7)
reg rp_trd if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_trd if year==2015, lag(7)
reg rp_sto if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_sto if year==2015, lag(7)
reg rp_snd if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_snd if year==2015, lag(7)
reg rp_mal if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_mal if year==2015, lag(7)
reg rp_lul if year==2015
hettest
estat bgodfrey, lags(7)
newey rp_lul if year==2015, lag(7)

*** Newey-West regression of price differences against mean by area and year ***
reg arh_sys if year==2008
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2008, lag(7)
reg cph_sys if year==2008
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2008, lag(7)
reg hel_sys if year==2008
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2008, lag(7)
reg osl_sys if year==2008
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2008, lag(7)
reg trd_sys if year==2008
hettest
estat bgodfrey, lags(7)
```

```
newey trd_sys if year==2008, lag(7)
reg sto_sys if year==2008
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2008, lag(7)


reg arh_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2009, lag(7)
reg cph_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2009, lag(7)
reg hel_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2009, lag(7)
reg osl_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2009, lag(7)
reg trd_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2009, lag(7)
reg sto_sys if year==2009
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2009, lag(7)


reg arh_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2010, lag(7)
reg cph_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2010, lag(7)
reg hel_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2010, lag(7)
reg osl_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2010, lag(7)
reg trd_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2010, lag(7)
reg sto_sys if year==2010
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2010, lag(7)


reg arh_sys if year==2011
```

```
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2011, lag(7)
reg cph_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2011, lag(7)
reg hel_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2011, lag(7)
reg osl_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2011, lag(7)
reg trd_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2011, lag(7)
reg sto_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2011, lag(7)
reg snd_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey snd_sys if year==2011, lag(7)
reg mal_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey mal_sys if year==2011, lag(7)
reg lul_sys if year==2011
hettest
estat bgodfrey, lags(7)
newey lul_sys if year==2011, lag(7)

reg arh_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2012, lag(7)
reg cph_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2012, lag(7)
reg hel_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2012, lag(7)
reg osl_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2012, lag(7)
reg trd_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2012, lag(7)
reg sto_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2012, lag(7)
```

```
reg snd_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey snd_sys if year==2012, lag(7)
reg mal_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey mal_sys if year==2012, lag(7)
reg lul_sys if year==2012
hettest
estat bgodfrey, lags(7)
newey lul_sys if year==2012, lag(7)

reg arh_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2013, lag(7)
reg cph_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2013, lag(7)
reg hel_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2013, lag(7)
reg osl_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2013, lag(7)
reg trd_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2013, lag(7)
reg sto_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2013, lag(7)
reg snd_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey snd_sys if year==2013, lag(7)
reg mal_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey mal_sys if year==2013, lag(7)
reg lul_sys if year==2013
hettest
estat bgodfrey, lags(7)
newey lul_sys if year==2013, lag(7)

reg arh_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2014, lag(7)
reg cph_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2014, lag(7)
reg hel_sys if year==2014
hettest
```

```
estat bgodfrey, lags(7)
newey hel_sys if year==2014, lag(7)
reg osl_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2014, lag(7)
reg trd_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2014, lag(7)
reg sto_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2014, lag(7)
reg snd_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey snd_sys if year==2014, lag(7)
reg mal_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey mal_sys if year==2014, lag(7)
reg lul_sys if year==2014
hettest
estat bgodfrey, lags(7)
newey lul_sys if year==2014, lag(7)

reg arh_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey arh_sys if year==2015, lag(7)
reg cph_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey cph_sys if year==2015, lag(7)
reg hel_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey hel_sys if year==2015, lag(7)
reg osl_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey osl_sys if year==2015, lag(7)
reg trd_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey trd_sys if year==2015, lag(7)
reg sto_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey sto_sys if year==2015, lag(7)
reg snd_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey snd_sys if year==2015, lag(7)
reg mal_sys if year==2015
hettest
estat bgodfrey, lags(7)
newey mal_sys if year==2015, lag(7)
reg lul_sys if year==2015
```

```
hettest
estat bgodfrey, lags(7)
newey lul_sys if year==2015, lag(7)

*** Newey-West regression of risk premium against time to maturity ***
reg rp_arh ttm
hettest
estat bgodfrey, lags(7)
newey rp_arh ttm, lag(7)

reg rp_cph ttm
hettest
estat bgodfrey, lags(7)
newey rp_cph ttm, lag(7)

reg rp_hel ttm
hettest
estat bgodfrey, lags(7)
newey rp_hel ttm, lag(7)

reg rp_osl ttm
hettest
estat bgodfrey, lags(7)
newey rp_osl ttm, lag(7)

reg rp_trd ttm
hettest
estat bgodfrey, lags(7)
newey rp_trd ttm, lag(7)

reg rp_sto ttm
hettest
estat bgodfrey, lags(7)
newey rp_sto ttm, lag(7)

reg rp_snd ttm
hettest
estat bgodfrey, lags(7)
newey rp_snd ttm, lag(7)

reg rp_mal ttm
hettest
estat bgodfrey, lags(7)
newey rp_mal ttm, lag(7)

reg rp_lul ttm
hettest
estat bgodfrey, lags(7)
newey rp_lul ttm, lag(7)

*** Newey-West regression of risk premium against variance and skewness ***
reg rp_aggr var_area var_sys skew_area skew_sys
hettest
estat bgodfrey, lags(7)
newey rp_aggr var_area var_sys skew_area skew_sys, lag(7)
```

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