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Trading time seasonality in the Nordic electricity market

Evidence from System and EPAD futures

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ABSTRACT:
In the Nordics, the electricity market consists of two markets: a physical day-ahead (better known as spot) market and a financial market. The spot market acts as an underlying market for electricity futures. In the spot market, hourly prices for the next day are determined in a daily auction among producers, retailers and industrial consumers. Nordic spot prices can be very volatile depending on factors such as power demand, hydrological balance, available transmission capacity, renewable energy production, and nuclear output. In the financial market for electricity there are two types of futures products. System futures which are settled against system spot-price, and EPAD futures which are area-specific products that are settled against the difference between area-specific spot price and system spot price.

Electricity consumption in the Nordics is seasonal as demand is higher during winter months compared to summertime as in wintertime electricity is used for heating purposes. The seasonality in power consumption is typically reflected in the so-called future's curve since summer months and quarters tend to be priced at lower level compared to the corresponding winter months. In other words, winter months are riskier and are priced higher for this reason. However, electricity futures can also display another type of seasonality that is not dependent on the underlying spot-price, delivery period, or time to maturity. This seasonality is called time seasonality, and it results from the electricity market being incomplete. Unlike traditional financial assets, electricity is a non-storable asset and thus electricity future prices don't converge with the underlying asset price as trading ceases before the delivery period. Therefore, it's almost certain that the average spot of the delivery period differs from the last quotation of the future's price.

This thesis studies time seasonality of two types of annual futures product: traditional system future (SYS) and synthetic future product for the Finnish price area (SYS+EPAD). Results of nonparametric tests show that yearly SYS and SYS+EPAD futures tend to be lowest around springtime (March – April), and prices reach the highest levels in autumn (August-September) and just before the end of the year (November – December). As expected, time seasonality is more pronounced for SYS+EPAD futures compared to SYS futures. For SYS+EPAD futures, the time seasonality effect is stronger for front year 1 futures compared to front year 2 futures.

CAPM regressions show that "Buy in April, Sell in November" and "Buy in March, Sell in December" trading strategies can generate statistically significant and positive alpha for both SYS front year 1 and SYS+EPAD Front 1 Futures. However, alpha levels can be only described as modest or moderate. For SYS Font Year 2 and SYS+EPAD front year 2 the results are mostly statistically insignificant, therefore the results cannot be recommended for practical application.

KEYWORDS: Commodities, Electricity markets, Nord Pool, Futures, EPAD's, Time seasonality, Capital asset pricing model

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TIIVISTELMÄ:

Pohjoismaissa sähkömarkkinat koostuvat kahdesta eri markkinasta: fyysisestä spot-markkinasta sekä finanssimarkkinasta. Spot-markkinalla seuraavan vuorokauden tuntihinnat määräytyvät kysynnän ja tarjonnan mukaan sähkön tuottajien ja ostajien välisessä huutokaupassa. Spot-hinnat voivat olla hyvin vaihtelevia riippuen mm. sähkön kysynnästä, uusiutuvan energian tuotannosta, ja pohjoismaisista vesivarannoista. Sähkön finanssimarkkinalla on puolestaan tarjolla kahdenlaisia futuurituotteita: systeemi- ja aluehintaerotuotteita. Systeemifutuurit koskevat koko yhteispohjoismaista sähkömarkkinaa, kun taas aluehintaerotuotteet ovat hinta-aluekohtaisia. Systeemifutuurien arvo määrittyy toteutuneen spot-hinnan keskiarvon perusteella, kun taas aluehintaerotuotteiden arvo perustuu aluekohtaisen spot-hinnan ja systeemi spot-hinnan väliseen erotukseen.

Sähkökulutus Pohjoismaissa on kausiluontaista johtuen korkeammasta kysynnästä talviaikana, kun sähköä käytetään lämmitykseen. Kulutuksen kausiluonteisuus on nähtävillä niin sanotussa futuurikäyrässä, jossa kesäkuukaudet ja -kvartaalit hinnoitellaan matalammalle tasolle kuin talviajanjaksot. Tämän kausittaisuuden lisäksi sähköfutuureissa voidaan nähdä myös ns. ajallista kausittaisuutta, joka ei ole riippuvainen futuurin hinnan perustana olevasta spot-hinnasta, futuuria koskevasta ajanjaksosta, tai ajasta futuurin erääntymiseen. Sähkömarkkinoiden yksi erityispiireistä on se, että sähköä ei varastoida samalla tapaa kuin muita kulutushyödykkeitä. Sähköfutuurien kaupankäynti päättyy ennen toimitusjakson alkua, jonka vuoksi on lähes varmaa, että toimitusjakson spot-hinnan keskiarvo poikkeaa futuurin viimeisestä noteerauksesta. Näiden seikkojen vuoksi sähköfutuurien hinnoittelu ei ole yksiselitteistä, ja sähkömarkkinoita voidaan kuvailla epätäydellisiksi.

Tässä tutkielmassa tutkitaan vuosittaisten systeemifutuurien (SYS) ja Suomen hinta-alueen futuurituotteiden (SYS+EPAD) ajallista kausittaisuutta. Tilastolliset testit osoittavat, että SYS sekä SYS+EPAD futuurituotteiden hinnat ovat tyypillisesti alhaisimmillaan keväällä maalis- ja huhtikuussa. Vastaavasti korkeimmat hinnat nähdään syksyllä ja juuri ennen vuoden loppua. Ajallisen kausittaisuuden vaikutus on korostuneempi SYS+EPAD futuureille verrattuna SYS futuureihin. Myöskin SYS+EPAD futuureissa ajallisen kausiluonteisuuden vaikutus on voimakkaampi seuraavan vuoden futuurituotteille verrattuna sitä seuraavan vuoden futuureille.

CAP-hinnoittelumallin mukaan sijoitusstrategiat, jossa futuurituotteita ostetaan huhtikuussa ja myydään marraskuussa tai ostetaan maaliskuussa ja myydään joulukuussa voivat tuottaa tilastollistesti merkittävää ylituottoa suhteessa markkinaportfolioon, kun kyseessä seuraavan vuoden futuurituotteet. Tuottojen tasoja voidaan kuitenkin pitää vain maltillisina. Tulevan vuoden jälkeiselle vuodelle tulokset ovat pääosin tilastollisesti merkityksettömiä, ja täten strategiaa ei voida suositella käytännön sovelluksiin kyseisten tuotteiden osalta.

AVAINSANAT: Hyödykkeet, sähkömarkkinat, Nord Pool, Futuurit, Aluehintaerotuotteet, Ajallinen kausittaisuus, CAP-hinnoittelumalli

Contents

Pictures

Figures

Tables

Abbreviations

EPAD	Electricity price area difference
CAPM	Capital asset pricing model
SYS	System future
TSO	Transmission system operator

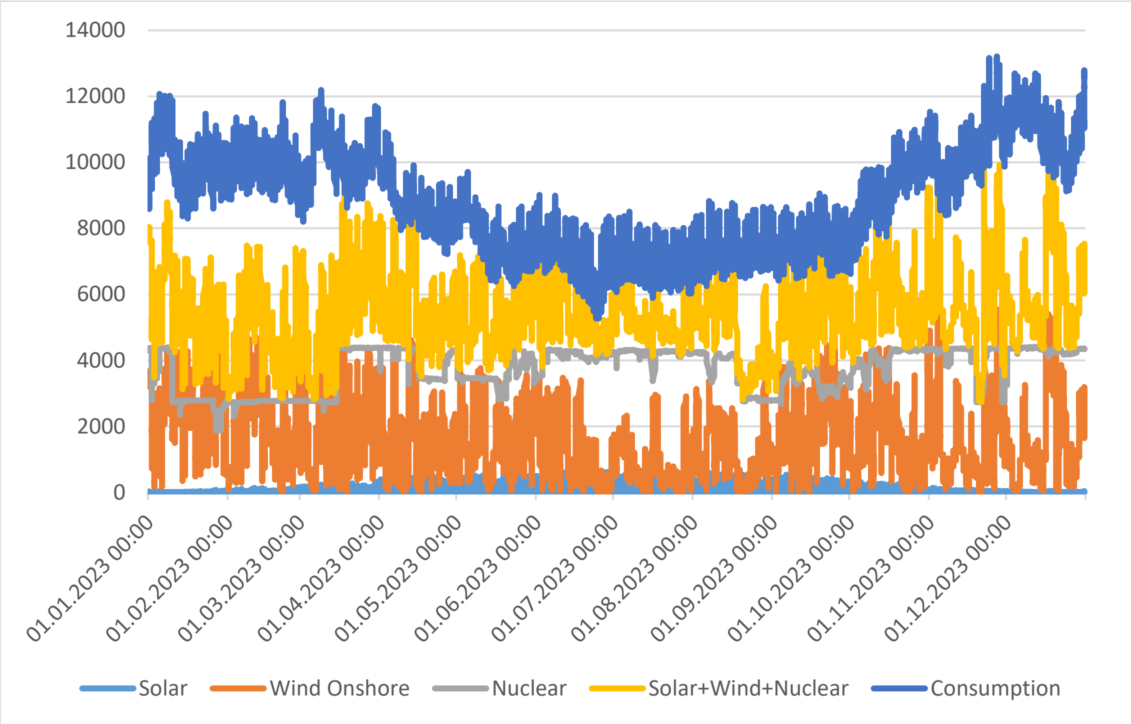
1 Introduction

Electricity prices and markets have become a topic of public interest these days, as we have seen spot prices climb to record highs in the past few years. In 2022, Finnish spot price averaged ~154 €/MWh which was significantly higher than any other year in the 21st century. On the other hand, near-zero and negative spot prices have not ever been this common due to the growth of renewable production across the Nordics. To give an example of this, there was total of 467 negative spot price hours in Finland during the year 2023 which was substantially more than ever before (Yle, 2023). Negative spot prices may occur for various reasons but usually factors such as fixed feed-in-tariffs, profit from selling GoO's (renewable producers get Guarantees of Origin for every MWh that they produce which they may sell to electricity retailers, brokers, or industrial consumers), and nuclear ramping limitations cause negative prices (Montel News, 2024). It seems that high volatility has become a new normal in the spot and futures market for electricity. Increasing volatility means more risk for e.g., consumers, retailers, and producers but it also may provide opportunities for all kinds of market participants.

In the Nordic market model, electricity is traded in two different markets: the physical day-ahead and the financial market. Day-ahead market refers to Nord Pool's daily auction where prices are determined for each hour of the following day. Due to limited transmission capacity, Nord Pool's market area is divided into a total of 15 different price areas. In the daily auction market participants place their ask and bid offers and based on these offers hourly spot prices are calculated daily for each individual area. Nord Pool is a physical market which means that all market participants such as electricity retailers, producers, and industrial companies are balancing responsible for local TSO's (Transmission System Operators) which essentially means that market participants need to maintain their power balance continuously. (Nord Pool, 2025a).

Futures trading for electricity takes place in Nasdaq OMX Commodities which is purely a financial market, meaning that all trades are settled financially against the realized spot price. In the financial market, futures trades are made for forthcoming and fixed time periods such as weeks, months, quarters, and years ahead from the present moment. There are two types of futures products in the financial market for electricity: System futures that are settled against system spot price which is the theoretical price for the whole Nord Pool market area, and EPAD (Electricity Price Area Difference) futures which are specific to certain price areas. Thus, EPAD's are often used to hedge against so-called price area risk which is caused by the limited transmission capacity within the market area and bottleneck situations. System futures and EPAD's are discussed in more detail in chapter three. By combining a system future and EPAD product, market participants may create an area-specific synthetic futures product that hedges equally against market and area price risks. In this thesis, the focus will be on yearly system futures and Finnish EPAD's in the period 2018 – 2023. In the context of electricity futures, a yearly product means that delivery period lasts for the entire calendar year.

In general, price seasonality refers to spot or futures price movements that are cyclical throughout the years (Ewald et al., 2022). In the Nordics, where temperature changes within the same year are high due to cold winters and relatively warm summers, electricity spot prices are seasonal depending on time of the year. In the summer demand for electricity is much lower compared to winter when electricity is used for heating purposes. For example, in Finland the total electricity consumption usually varies between 6 000 – 8 000 MW per hour during summertime but consumption can reach up to 12 000 – 15 000 MW per hour in the winter depending on how cold the weather gets. Finnish electricity consumption, renewable (wind and solar) production, and nuclear output during year 2023 is presented in picture 1.



Picture 1. Finnish electricity consumption, renewable production, and nuclear output in 2023 (adapted from SKM Market Predictor, 2024).

Due to seasonal demand, spot prices tend to be lower in the summer and respectively peak during the winter months. Therefore, it makes sense that system future prices for summer months, e.g. June, July, and August, are usually traded at a lower level compared to the fall and winter months, e.g. December, January, and February. However, seasonal demand is not necessarily the only reason why futures prices for summer months are cheaper compared to the winter months as so-called risk premium may also lift prices for winter months. For example, Lucia & Torro (2008) and Gjolberg & Brattested (2011) have found higher ex-post risk premiums for winter periods compared to other seasons of the year. Since in the academic literature regarding electricity markets term "risk premium" is somewhat ambiguous, it is decided that in this thesis positive premium refers to futures prices exceeding realized spot price, and negative premium means futures prices lower than realized spot price. Gjolberg & Brattested (2011) argue that high risk premiums (5 -8 % on an annual basis) results from the market being immature and inefficient, and from risk avoiding behavior from the electricity users.

Lucia & Torro (2008) studied the seasonality of risk premium in the Nordic electricity market and found that risk premium for short-term weekly futures is zero during summer and spring, slightly positive for fall, and significantly positive for winter. Furthermore, Gjolberg & Brattested (2011) found that risk premium for 4-weeks ahead futures is highest in January, February, and July, and for 6-weeks ahead futures premium peaks in June, December, and January. They consider that high risk premiums during mid-summer might be caused by dry weather conditions and weak hydro balance which increases the price risk for the upcoming winter period. However, although they find some seasonality in risk premium, they also conclude that premium does not significantly differ across the seasons of the year, and it remains positive throughout the year.

Seasonality of electricity futures can be studied from maturity or trading time perspective. Maturity time refers to the time remaining until a futures contract expires. For electricity futures, maturity time includes both the time remaining until the delivery starts and the whole delivery period. This type of seasonality is typically seen in the so-called future curve which reflects seasonality of the spot prices. However, futures prices can also show seasonality that is independent from the underlying spot price or remaining time to maturity. This type of seasonality can be described as time seasonality, and it often relates to seasonal risk preferences of market participants and hedging pressure of electricity buyers. Time seasonality is connected to the no-arbitrage assumptions, and it can be seen as statistical patterns in the backward curve. More detailed theoretical approach to time seasonality is presented in chapter two of this thesis.

Trading time seasonality hasn’t gotten much attention in academic literature, but it has been studied by e.g., Størdal et al. (2023) and Ewald et al. (2022). In both research papers authors first conduct nonparametric tests as they try to reveal which trading months are stochastically dominating other months. In other words, they try to find out in which trading months prices tend to be the lowest, or respectively the highest. Based on the results of nonparametric tests, authors then create time seasonality-based trading strategy which is then tested in an empirical model. This thesis follows the same methodology as the formerly mentioned studies.

Størdal et al. (2023) studied time seasonality in the Nordic and German electricity markets during years 2006 – 2021. They found that in both Nordic and German markets annual products typically reached their lowest levels in February. Respectively, the highest prices on average occurred in July and August. They applied their findings as they tested simple long-short trading strategy in which futures were bought in February and sold away in August. In the context of capital asset pricing model, they found higher positive alphas in German market compared to Nordics in all selected portfolios (1 year ahead, 2+3 years ahead, 4+5 years ahead). Positive and statistically significant alphas indicates that time seasonality is indeed an arbitrage opportunity that can beat the market continuously. In both markets, 1 year ahead portfolio provided higher excess returns than portfolios 2+3 and 4+5 years ahead. In the research, OMX Nordic 40 index was used as proxy for market portfolio in the Nordics, and respectively DAX index for German market.

Ewald et al. (2022) studied time seasonality in the Henry Hub natural gas and West Texas intermediate (WTI) crude oil markets. They found that regardless of futures product maturity time, prices of natural gas futures peak in June and bottom out in February. Correspondingly, oil prices tend to be highest in July, and lowest in December. Similar to methodology of Størdal et al. (2023) they also conducted CAPM analysis and found that “buy low months, sell high months” trading strategy has produced statistically significant alphas compared to market portfolio. S&P 500 stock index was used as a proxy for both natural gas and crude oil markets. Although the research provides clear evidence of the existence of time seasonality in these markets, the exact source of why it exists remains unclear for both Størdal et al. (2023) and Ewald et al. (2022). They speculate that factors such as seasonal hedging pressures of different market participants, ESG related risks and human behavioral factors could influence why time seasonality exists in these markets, but more detailed analysis is left for further research.

1.1 Purpose and hypotheses of the thesis

After the energy crisis of 2022, spot prices and electricity futures have gained a lot more interest in the media and among the public. In academic literature regarding Nordic electricity futures, most of the research only focuses on system futures whereas EPAD futures have gotten very little attention although it has been seen in recent years that in some Nordic areas prices can deviate significantly, either positively or negatively, from the Nordic system price. History has proven that changes to the realized area price difference between months, weeks, or days can be quite drastic depending on the weather conditions and operational situation of crucial power plants and transnational transmission cables. Therefore, the system future itself may be a poor indicator of the spot price for some areas, and for this reason e.g. hedging with only system futures may pose a large price risk for industrial consumers that want to fix their energy costs, or alternatively for retailers that have sold fixed price contracts to households and businesses.

Finland is a good example of a price area that has experienced large area price differences in the recent years. Finland has one of the most volatile electricity markets in the Europe due to rapid growth of renewables, lack of flexibility in the power system, and its dependency on the nuclear availability (Montel News, 2024). For example, in November of 2022 Finnish area price was delivered ~86 €/MWh higher on average compared to the system spot price (system spot was delivered at ~109 €/MWh). On contrary, in March of the same year Finnish spot was delivered ~58 €/MWh lower on average than system spot (system spot was delivered at ~145 €/MWh). To provide some context, in 2022 yearly average for Finnish area price difference was ~14 €/MWh. In this thesis, EPAD futures are included in the analysis since they are clearly an important price component in some price areas, like Finland. From the pricing standpoint, Finnish EPAD's are interesting product as the changes in the realized area price can be quite drastic day-to-day but EPAD's value depends on the realized average of the area price difference. This may lead to a situation where a single day has significant impact on the whole month's average if spot prices spike only in Finland due to e.g. weak domestic renewable production, limited transmission capacity between Finland and Sweden, high demand caused by cold weather, and lack of nuclear capacity, but at the same Nordic system price stays at relatively normal level. For example, on January 5th, 2024, the realized area price difference on a single day was ~750 €/MWh. This obviously had a significant impact on the monthly average as there are 744 hours in January.

The purpose of this thesis is to gain more knowledge about seasonal behavior of two types of annual future products in the Nordics: standard system future product (SYS) and area-specific synthetic future product (SYS+EPAD). Størdal et al. (2023) have previously studied time seasonality of Nordic system futures. However, to my knowledge time seasonality has not been previously studied from an area-specific synthetic futures perspective. The following hypotheses are formed and studied in this thesis.

Hypotheses 1: There is more time seasonality found in synthetic SYS+EPAD future compared to SYS future.

This hypothesis is based on the imbalance of between buyers and sellers in the Finnish EPAD market, and the higher price risk involved in the Finnish price area due to Finland's dependency on the imported electricity and high fluctuations in the Finnish renewable production.

In the past years, Finland has typically consumed more electricity than it produces, meaning that Finland has been a net-importer of electricity. As a result of this production-consumption imbalance, there are fewer natural sellers (typically electricity producers) of EPAD's compared to natural buyers (typically utilities and large industrial consumers). Lack of natural EPAD sellers has been previously highlighted in the research by Junttila, Myllymäki & Raatikainen (2018) as they analyzed risk premium in the Finnish

EPAD market. Another EPAD research by Spodniak et al. (2014) don't specifically mention Finland but generally acknowledges that many Nordic price areas suffer from high bid-ask spreads and lack of sellers in the EPAD market.

In a situation where there's buying interest in the market but lack of sellers, this may result in single trade causing significant price movements in the market, and thus more pronounced time seasonality. The financial market for electricity is open to other market participants than natural sellers that are looking to hedge their physical production and therefore, in theory, non-physical participants could sell EPAD products and thus boost market liquidity. However, very low trading volumes in the Finnish EPAD market indicate that there aren't speculators or other purely financial players participating in the market. Before the start of the delivery period the total traded amount through Nasdaq, also known as the open balance, for YR-23 EPAD product was 1092 MW which is equal to 9,5 TWh. In comparison, annual consumption in Finland has been around 80 TWh during years 2018 – 2023 meaning that EPAD trading in Nasdaq covered only ~12 % of the total annual consumption in Finland. For YR-22 EPAD the open balance was 1653 MW (14,5 TWh), and for YR-21 it was 1753 MW (15,4 TWh). Open balance data was obtained from SKM Market Predictor Online service. Lack of liquidity is not only a problem in the Finnish price area as Thema Consulting Group (2022) analyzed hedging opportunities in the Finnish, Estonian, Latvian, and Lithuanian bidding zones in the period of 2002 – 2021, and they found even lower trading volumes and open balance/physical consumption ratios for Latvian and Estonian EPAD's compared to Finnish EPAD's.

As the year goes on, there is more information available that affects the pricing of EPAD's for upcoming years. For example, market participants know more about hydrological balance, growth of renewable energy production, and operational situation of Finnish power plants. Winter periods are especially risky from the Finnish EPAD standpoint as consumption in Finland is much higher compared to the summer, and thus Finland is more dependent on the imported electricity. This was especially the case before the commission of Olkiluoto 3 nuclear power plant. Therefore, there's more risk involved when EPAD’s are included, especially in situations where the Nordic hydro balance is at weak level heading towards winter period. To summarize, due to higher price risk in the Finnish price area, it is expected that there is more time seasonality found in synthetic SYS+EPAD futures compared to just SYS products.

Hypotheses 2: Time seasonality effect is stronger in front year 1 products compared to front year 2 products.

Front year 1 products are closer to the beginning of the delivery period, and therefore it is expected that changes in market conditions e.g. development of hydrological balance, political decisions such as energy support schemes and emission trading system (EU ETS), operational situation of transmission cables, market prices in neighboring markets such as Germany and the UK, or nuclear output causes stronger price reactions for front year 1 futures compared to front year 2, and thus stronger time seasonality effect.

Hypotheses 3: Trading time seasonality of SYS+EPAD products will generate more positive alpha than SYS products in the context of capital asset pricing model.

The underlying argument for this hypothesis is that Finnish EPAD market is inefficient due to lack of market liquidity. The efficient market hypothesis by Eugene Fama (1970) argues that market prices reflect all the available and relevant information and for this reason it’s not possible to “beat the market” as there aren’t any undervalued or overvalued assets. Correspondingly, inefficient market means that all relevant information is not incorporated into prices, and therefore it’s possible to find consistent excess returns even with a simple long-short trading strategy. This hypothesis is lined with the results of Størdal et al. (2023) as they found that trading time seasonality for Nordic system futures has beaten the market from June 2006 to February 2021. It is expected that when EPAD products are added on top of SYS futures, this results in even higher excess returns in the context of CAPM.

As mentioned earlier, EPAD trading for the Finnish price area only covers small proportion of the actual consumption in Finland which strongly indicates lack of liquidity in the EPAD market. Nordic energy research's report (2024) also acknowledges EPAD's markets inefficiency, and notes that overall market liquidity has steadily declined after American companies withdrew from the Nordic power market after the financial crisis of 2008.

Changes in the regulatory framework have also contributed to the lack of liquidity in the financial market of electricity. To reduce counterparty risk in the market and the introduction of regulatory EU directives such as MiFID II (Markets in Financial Instruments Directive II) and EMIR (European Market Infrastructure Regulation), bank guarantees were no longer accepted as collateral for electricity futures which had previously been cost-effective way to participate in the financial market for electricity. This ban reduced liquidity since futures trades had to be backed up by cash or exchange-listed securities. Banning bank guarantees meant that trading required much more capital and this caused many small and medium sized participants to exit the Nasdaq financial market and switch to bilateral OTC trading according to report by Holtz et al. (2022).

PPA's may also have contributed to declining liquidity in the financial market. Thema Consulting Group's report (2021) for Norwegian TSO, Stattnet SF, studied hedging opportunities in the Norwegian electricity market. In the report, it's pointed out that the attractiveness and availability of PPA contracts is one of the possible reasons why liquidity has escaped from the financial market. Power Purchase Agreements (PPA's) are usually long-term contracts, typically 5-20 year, meaning that only a fraction of the total volume may come to the futures market if a significant share of project's capacity is hedged bilaterally through PPA's. The report acknowledges that PPA volumes have increased significantly not only in Norway but also in the other Nordic countries.

To summarize, liquidity in the EPAD market has been in constant decline due to:

1) Asymmetric power balances in some price areas such as Finland which leads to lack of natural sellers
2) Exit of financial players after the financial crisis
3) The limitation of using bank guarantees as collaterals
4) Growth of the PPA contracts

For Nordic system futures there haven't been similar issues regarding liquidity and efficient pricing as there are more participants who want to hedge their production or consumption against the system price, and the overall trading volume is not divided between several price areas.

Market participants know that the lack of liquidity is an issue, and therefore, e.g. consulting companies have come up with ideas to improve liquidity in the EPAD market. These ideas usually involve some kind of intervention in the market by Transmission System Operators. For example, a report by Thema Consulting Group & Hagman Energy (2015) suggests that local TSO's could act as market makers in the EPAD market and thus provide "base volume" in the market and tighter bid-ask spreads. Their other ideas include auctioning EPAD contracts or FTR options (Financial Transmission Rights). FTR option is a financial right between two bidding zones that gives the owner the right to receive the price differential for each hour if it is positive in the direction of the FTR-option. Respectively if the price differential is negative, the owner has no obligation to buy the price difference. Auctioning FTR options would be somewhat riskless for TSO's if the auctioned FTR volumes were the same but in the opposite directions as they would offset each other. In 2024, Svenska Kraftnät (Swedish TSO) launched a pilot project to improve liquidity in the Swedish electricity market by auctioning to buy and sell EPAD's in price areas SE2 (Sundsvall), SE3 (Stockholm), and SE4 (Malmö). The results of this pilot are still unknown at this moment.

Regarding the previous research, Finnish EPAD market is a very lightly studied research field but possible market inefficiency in the Finnish EPAD market is discussed in the research by Junttila, Myllymäki & Raatikainen (2018) as they write: *"However, it is also obvious that there are arbitrage opportunities in the financial market segment of the Finnish electricity markets, because the excess futures premium is positive and statistically significant in every specification considered so far. This speaks for the possibility that the Finnish EPADs market might not be efficient"*

In this thesis, a total of 4 different future products is selected for further analysis:

- System future 1 year ahead
- System+EPAD (Finland) future 1 year ahead
- System future 2 years ahead
- System+EPAD (Finland) future 2 years ahead

1.2 Structure of thesis

The remainder of this thesis is organized as follows. The theoretical backgrounds of futures pricing, time seasonality, and capital asset pricing model are presented in chapter 2. The fundamental basics of the Nordic power market, more precisely Nord Pool day-ahead and Nasdaq financial market are introduced in chapter 3. Data and descriptive statistics are presented in chapter 4. Empirical results are presented in chapter 5. Chapter 6 summarizes the thesis and discusses how and whether the results can be utilized in practical terms.

2 Theoretical background

2.1 Theory of commodity futures

2.1.1 Introduction to futures

In short, a futures contract is an agreement between two parties to buy or sell a certain asset in the future at a predetermined price. Traditionally, future markets can be divided into bilateral over-the-counter (OTC) markets and future exchanges such as Nasdaq OMX Commodities for electricity. In the OTC markets, market participants can negotiate specifics of the deal themselves and hence trades can be made for any volume and for any settlement date. One of the disadvantages of OTC trading is the counterparty risk which means that the opposing party of the transaction is not able to fulfill its contractual obligations. This risk virtually doesn't exist in futures exchanges as its role is to provide safety mechanisms such as daily margin requirements and base collaterals to avoid defaults (Nasdaq, 2025). Futures traded through exchanges are standardized products which means that trading is possible even if participants don't know each other. Also, in the future exchanges trading is more transparent compared to OTC trading as market participants can see all the trading activity that is taking place, and all the bid and ask offers currently placed in the market. Futures are usually settled financially but, in some cases, may lead to actual physical delivery. (Hull, 2003, pp. 1-2 & 21).

2.1.2 The payoff from a futures contract

There are always two sides of a futures transaction: buyer and seller. Buying a future is often referred to as taking a long position, and correspondingly selling is called taking a short position. If the price of the underlying asset goes up and exceeds the delivery price, the buyer ends up making money from a trade, and vice versa. Buyers' payoff (taking a long position) from a futures trade is defined in equation 1:

$$S_T - K \tag{1}$$

where S_T is the spot price at maturity of the contract, and K is the delivery price. For seller (short position), the payoff is the opposite to the buyer (equation 2).

$$K - S_T \tag{2}$$

The payoff from a future trade can be positive, negative, or zero depending on how the spot price develops compared to the delivery price. Future trading can be described as zero-sum game since one's gain is equivalent to another's loss. The majority of futures are closed out before maturity. Closing out on position means that a trader enters a trade that is opposite to the original trade. For example, if a trader initially bought a certain amount of stock index futures, then position is closed by selling corresponding amount of the same stock index futures. In this case, the trader's profit/loss is determined by the difference between the initial purchase price and the market price when the position is closed. (Hull, 2003, pp. 3- 4 & 20).

2.1.3 Reasons for future trading - hedging, speculation and arbitrage

Trading reasons in the futures markets can be roughly divided into three different categories. These categories are hedging, speculation, and arbitrage. Hedgers want to reduce the risk of unfavorable market movements, speculators take bullish or bearish view on the market or certain asset and look to make profit this way, and arbitrageurs look to lock in profit by taking two or more offsetting positions.

The basic idea in hedging is to improve the certainty of outcome in the future. To give a few examples: transportation companies might want to fix part of their fuel costs, or companies that export lots of goods and services and operate in several different countries might want to hedge against unfavorable foreign exchange rate movements, or nuclear energy producers may want to improve the stability of the cash flow that they receive from selling their production in the spot market. Long hedges are often used when e.g. a company knows that it is going to purchase some specific assets in the future, and they want to lock the price now. Respectively, short hedgers already own an asset, and they plan to sell it some specific time in the future, e.g. four months or one year from the current moment. In addition to futures, options can also to be used for hedging purposes. The key difference between futures and option hedging is that futures contracts neutralize the risk of unfavorable price movements whereas options provide insurance and allow the option buyer to benefit from possible favorable price movements. Obviously, this insurance does not come without cost as the buyer of the option needs to pay a premium to the seller who is carrying the price risk in an option trade. (Hull, 2003, pp. 11 & 71-73).

In theory, futures contracts can completely neutralize the risk of how much hedger pays or receives in the future. However, this requires that the hedger knows the exact date when the asset will be bought or sold. Secondly, they need to be certain about the volume they plan to buy or sell. And thirdly, the asset needs to be the same as the underlying asset in the futures contract. For financial assets such as individual stocks and market indexes the underlying asset is typically the same as futures contract but for consumption assets this is not necessarily the case. If these conditions are not fulfilled, this results in a basis risk. (Cuthbertson & Nitzsche, 2001, p. 19).

The basis for financial assets is defined as in equation 3:

$$Basis = Spot\ price\ of\ hedged\ asset - Futures\ price\ of\ contract\ used \qquad (3)$$

If the asset and underlying future are the same, the basis converts to zero at the maturity. Prior to maturity, the basis can be either positive or negative. If a spot price increases more than futures prices, this situation is called strengthening of the basis. In reverse, the weakening of the basis occurs when futures price increases more than the underlying spot price. (Hull, 2023, pp. 74-75).

In a certain way, speculators are the opposite to hedgers as speculators don't want to avoid exposure to unfavorable market movements of some asset they plan to sell or buy in the future. Speculators look to predict and gain financially from the price changes in the market. In essence, speculators are betting that the market price will go up or down. This depends on their view of the market. Speculators can be divided into three different groups: scalpers, day traders, and position traders.

Scalpers have a very short trading horizon as they typically close out within minutes of their initial trade. The goal in this trading strategy is to profit from small price changes in the market and accumulate profit with numerous trades on each trading day. If the market price doesn't move in favorable direction from a scalper's perspective, they close out their position and start looking for new opportunities in the market. Compared to scalpers, day traders hold their position a bit longer. Usually, day traders close out their positions within a few hours of the initial trade, or they close out before the end of each trading day as they want to avoid overnight risk exposure. Day traders trade based on news and announcements that take place during the trading day. Lastly, there are position traders who hold their position for days or even months. Position traders often cover their risk exposure to some degree as they often engage in spread trading. This means taking multiple positions e.g. position trader could take a short and long position on same underlying asset but with different maturity dates. This example is called an intracommodity spread. If position traders don't engage in any type of spread trading, this is called having an outright or a naked position. Having an outright position may lead to large financial gains if position trader ends up being correct. However, this is very risky and can lead to disastrous results if the market moves significantly to the other way that was expected by the speculator. (Cuthbertson & Nitzsche, 2001, pp. 52-53; Hull, 2003, pp. 32-33).

2.1.4 Pricing of futures

Futures contracts can be divided into investment and consumption assets. For example, stock and bonds are clearly investment assets whereas electricity, natural gas and crude oil are examples of consumption assets since they are primally held for consumption. For investment assets and consumption assets that are storable, we may use no-arbitrage arguments to determine futures prices.

However, electricity is a non-storable asset which means that electricity that is delivered now is not the same asset as electricity delivered in the future. This leads to a situation where there is no price convergence between futures price and underlying commodity which in this case is spot electricity. Therefore, no-arbitrage arguments cannot be used to price electricity futures like they can be used to price investment assets and storable consumption assets. (Vehviläinen, 2002).

No-arbitrage arguments can be defined as below (Fama, 1970; Hull, 2003, p. 44)

1. There are no transaction costs or taxes for all market participants as they trade.
2. All market participants may borrow or lend money at the same and constant risk-free rate.
3. Trading in the market is conducted by a large number of different participants and liquidity in the market is sufficient.
4. There are no restrictions on short selling.
5. All market participants take advantage of arbitrage opportunities if they occur in the market.

With the risk neutral valuation, the futures price for an investment asset that provides no additional income, e.g. stock that doesn't pay dividend, can be defined as in equation 4:

$$F_0 = S_0 e^{rT} \tag{4}$$

Where F_0 is the futures price, S_0 is the price of the underlying asset, T is the remaining time to maturity, and r is the risk-free interest rate.

If there's an arbitrage opportunity e.g. $F_0 > S_0 e^{rT}$, a market participant could buy the asset, and short the futures contract which would lead to a riskless profit. Respectively, if $F_0 < S_0 e^{rT}$, market participants could short the asset and buy a futures contract.

In theory, the pricing of futures is relatively simple for investment assets that don't provide additional income. Pricing gets a bit more complicated for consumption assets as the cost of storage must be considered into pricing equation. Also, the convenience yield is an important factor for some physical commodities. The convenience yield refers to benefiting from holding the physical asset compared to financially settled futures contract. For example, an oil refiner may hold crude oil in the inventory and use it whenever they want and thus can try to benefit from possible short-term shortages in the oil markets. A financially settled futures contract for crude oil does not offer this same benefit. Another example of benefitting from owning a physical asset is hydro power producers that may store water in their hydro reservoirs and optimize the value of their electricity production for longer periods of time. Electricity futures don't offer the same possibility as they are fixed baseload products that are settled financially against the delivered spot-price. (Hull, 2003, pp. 58-60).

Futures price for storable consumption assets can be defined as in equation 5:

$$F_0 = S_0 e^{(r+u-y)T} \tag{5}$$

Where u is the constant storage cost related to spot price, and y is the convenience yield. Typically, if convenience yield is very low, this means that shortages of asset S_0 are unlikely as current storage levels are high. And respectively, high convenience yield means low inventories and high likelihood that shortage situations occur in the market.

The link between spot electricity and electricity futures is weaker compared to e.g. investment assets and storable consumption assets as electricity is a non-storable commodity. Due to this special feature of non-storability electricity delivered today is not the same asset as the electricity delivered sometime in the future. Also, the underlying asset for electricity futures is the average spot price in the delivery period, and trading with electricity futures ends before the delivery period begins. Therefore, it is almost certain that the average spot price in the delivery period differs from the last quotation in the futures market. This means that futures prices don’t converge with the underlying spot price. However, it can be argued that before trading ceases the electricity future’s price converges into the risk-adjusted expectation of average spot price in the delivery period. To summarize, the futures market for electricity can be described as incomplete since there isn’t an arbitrage-free price relationship to the underlying spot price. (Vehviläinen, 2002).

2.2 Time seasonality

In the arbitrage-free financial market, it is expected that all futures will be priced in a consistent manner and determined by supply and demand. This means that there is a unique martingale measure $\mathbb{Q}$, also known as a risk neutral measure, and all financial instruments are calculated against this measure. However, a manifold of martingale can exist if the market is incomplete. As mentioned earlier, electricity futures don’t converge to the underlying spot price at maturity since trading ceases before the delivery period. Also, spot electricity is non-storable physical asset meaning that e.g. it’s not possible to buy physical electricity from the market, hold it for some time, and use it later or sell it back to the market. Therefore, the assumption of market completeness is not suitable for electricity. Under no-arbitrage assumptions futures prices are determined as in equation 6 where $\mathbb{Q}$ denotes the risk-neutral pricing measure, and $\mathbb{P}$ denotes the physical (spot) measure. $\mathbb{E}_t^{\mathbb{P}}$ is the conditional physical expectation measure, and respectively $\mathbb{E}_t^{\mathbb{Q}}$ is the conditional pricing expectation measure. $P(T)$ denotes the spot price at time T. The relationship between the physical measure $\mathbb{P}$ and the pricing measure $\mathbb{Q}$ is called the pricing kernel $\frac{d\mathbb{Q}}{d\mathbb{P}}$. (Størdal et al., 2022; Ewald et al., 2022; Vehviläinen, 2001).

$$F(t,T) = \mathbb{E}_t^{\mathbb{Q}}\left(P(T)\right) = \frac{\mathbb{E}_t^{\mathbb{P}}\left(\frac{d\mathbb{Q}}{d\mathbb{P}} * P(T)\right)}{\mathbb{E}_t^{\mathbb{P}}\left(\frac{d\mathbb{Q}}{d\mathbb{P}}\right)} \tag{6}$$

In the Nordics, spot prices are typically lower in the summer due to seasonal demand which causes futures prices for summer periods to be traded at lower levels compared to winter periods. This type of seasonality is often seen in the forward curve, which is the market's expectation of the future spot-price. This is represented by $P(T)$ on the right side of the equation.

In addition to seasonality in the forward curve $T \to F(t,T)$, pricing kernel $\frac{d\mathbb{Q}}{d\mathbb{P}}$ can also cause seasonality in the futures prices. This can also be identified in the realized seasonal statistical patterns in the backward curve $t \to F(t,T)$. Størdal et al. (2023) and Ewald et al. (2022) have named the seasonality that is reflected in the backward curve to time seasonality.

2.3 Capital asset pricing model

The capital asset pricing is based on the modern portfolio theory developed by Harry Markovitz in 1959. Key underlying assumption in Markovitz's model is that all investors are rational, risk-averse and choose only mean-variance efficient portfolios. This means that investors either choose portfolios that 1) maximize the expected return if the variance is given or 2) minimize the risk (portfolio variance) if an expected return is given. (Fama & French, 2004).

Portfolio investment opportunities are presented in figure 1. The vertical axis is the expected return, and the horizontal axis is the portfolio risk measured by standard deviation. The curve *abc* is called the minimum variance frontier for risky assets. For this curve, risk-free lending or borrowing is not included. An investor who wants a higher return must accept higher variance. Or respectively, if an investor wants lower variance, they then must accept lower return. In the minimum variance frontier, assets/portfolios above *b* are only efficient since they maximize return and minimize variance. When risk-free lending and borrowing is allowed (presented by the straight line from *Rf* to *g*), efficient frontier moves up to point *T* which is a combination risk-free asset and market portfolio. (Fama & French, 2004).

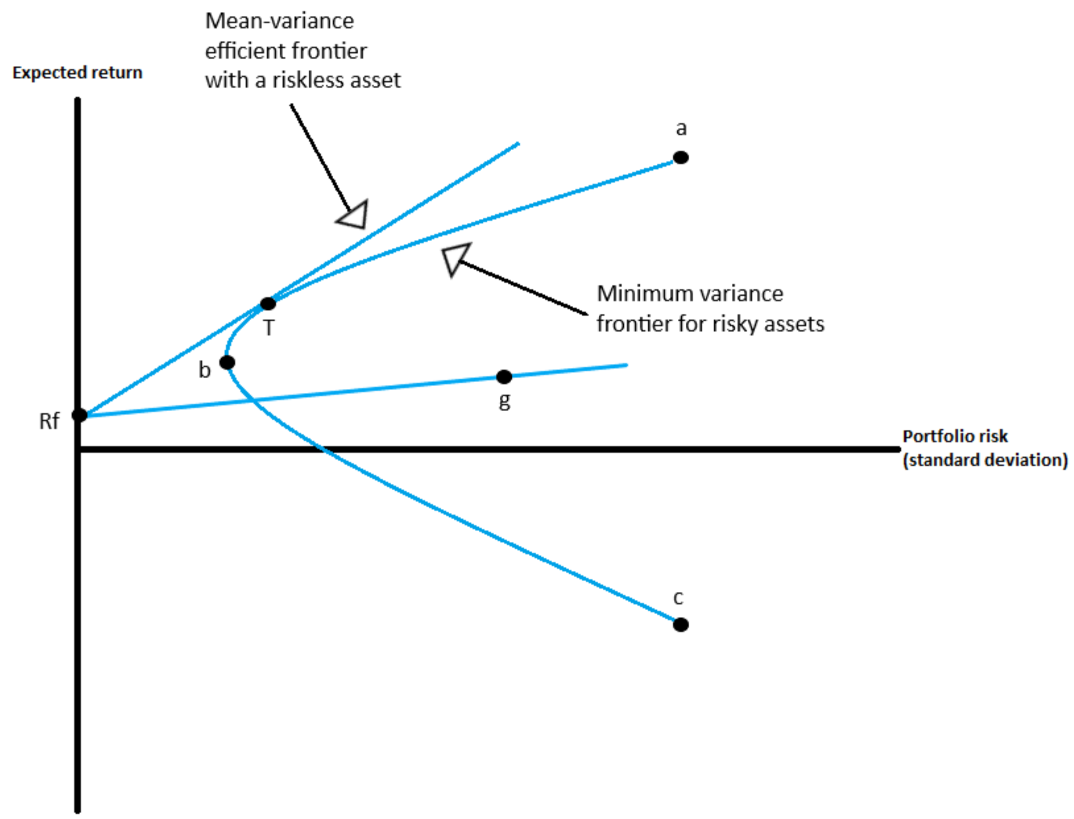


Figure 1. Portfolio investment opportunities (adapted from Fama & French, 2024).

William Sharpe (1964) expanded the work of Markovitz and introduced a linear model in which expected return of an asset is dependent on its systematic risk. The systematic risk refers to risk that cannot be diversified, whereas unsystematic risk affects the entire market and therefore cannot be reduced or eliminated through diversification. Asset's systematic risk is measured beta by (β_i). If the beta is equal to 1, this means that asset moves in line with the market. Respectively, $\beta_i > 1$ means that the asset is more volatile than the market and $\beta_i < 1$ means that it is less volatile.

Although CAPM is widely used, it is often criticized for its unrealistic assumptions such as all market participants can borrow and lend money at the same risk-free rate, ignoring human behavioral factors, and neglecting transaction costs or taxes. Also, CAPM assumes that there exists a true market portfolio that includes all possible assets. However, market indexes such as S&P 500 or OMX Nordic Energy Net Index are incomplete representations of the true market portfolio. Empirical tests of CAPM have shown that it does not predict returns as accurately as subsequent and more complex models, e.g. Fama-French 3-factor model, but nonetheless, CAPM has remained as important tool in the financial decision making and performance evaluation. (Fama & French, 2004 ; Elbannan, 2015).

Baxter et al. (1985) defines standard capital asset pricing model for commodities as in equation 7:

$$E(R_i) = R_f + \left[E(R_m) - R_f\right]\beta_i \tag{7}$$

where $E(R_i)$ is the expected return of asset i, R_f is risk-free rate, $E(R_m)$ is the expected return of market portfolio, and β_i is market sensitivity of asset i (equation 8).

$$\beta_i = \frac{Cov\,(R_i, R_m)}{\sigma_{R_m}^2} \tag{8}$$

The net supply of futures contracts is zero, meaning that each long position there must be corresponding short position. Also, the initial value of a future’s contract is zero, and thus absolute return of future contract can be defined as in equation 9:

$$E(P_1) - P_0 = R_f P_0 + \left[E(R_m) - R_f\right] \frac{Cov\,(P_1 - P_0\,, R_m)}{\sigma^2_{R_m}} \tag{9}$$

where P_0 is the beginning price of futures contract (long position), and P_1 is end price of same futures contract, R_f is risk-free rate, and R_m is market return. Entering a futures contract doesn't require initial investment other than daily collateral, meaning that P_0 is zero. In equation 10, ΔP denotes the change in future price over the period t.

$$E(\Delta P) = \left[E(R_m) - R_f\right] \frac{Cov\,(\Delta P\,, R_m)}{\sigma^2_{R_m}} \tag{10}$$

From equation 10, we may form a testable empirical model of the CAPM (equation 11):

$$r_i^t = \alpha_i + \beta_i^*\left(r_m^t - r_f^t\right) + \in_i^t \tag{11}$$

Where r_i^t is relative change is futures prices in period t, alpha α_i is excess return by the selected portfolio strategy, β_i^* is futures sensitivity to market portfolio, r_m^t is market return, r_f^t is a return of risk-free asset, and $\in_i^t$ is the regression error for period t. In theory, if there's an arbitrage opportunity that can be exploited by a certain trading strategy, it should produce statistically significant and positive alpha α_i.

3 Nordic power market

The Nordic electricity market consists of a total of four markets:

1) Nord Pool’s day-ahead market (also known as spot market)

2) Nord Pool’s intraday market

3) Balancing market operated by country’s TSO

4) Nasdaq’s financial market

This thesis focuses on Nasdaq’s financial market for electricity, and more precisely on the system and Finnish EPAD products. However, understanding the basics of day-ahead market is important since day-ahead market is the underlying market for the system and EPAD futures. Main differences between these two markets are summarized in the table 1.

Table 1. Summary of differences between day-ahead and financial markets.

Market	Day-ahead market (Nord Pool)	Financial market (Nasdaq)
Delivery	Physical delivery of electricity	System futures: financial settlement against realized average system spot price EPAD’s: financial settlement against average difference between delivered area price and spot price
Time period	Hourly prices for the next day	Monthly, Quarterly and Yearly products up to 10 years ahead
Marketplace	Daily auction at Nord Pool	Continuous trading on weekdays (Nasdaq and OTC-market)
Balancing responsibility	TSO responsible parties only	No requirement to be TSO responsible party. Open for financial participants.
Key price fundamentals	Renewable (wind and solar) production, temperature, hydro balance and reservoir levels, nuclear output, available transmission capacity.	Hydro balance, fuel prices, electricity prices in the neighboring markets, expected development of electricity demand, growth of renewables, investments in transmission capacity between different market areas.

Although Nord Pool’s intraday market and TSO’s balancing market are not relevant in the context of this thesis, it is worth mentioning that they both are complimentary markets to the day-ahead market where market participants may buy or sell electricity after day-ahead auction is completed. For example, electricity retailers can make additional purchases in the intraday market if they realize that their initial consumption prognosis has been too low for some hours of the following day, or if their purchase offers didn’t go through as planned in the spot market (Nord Pool, 2025b).

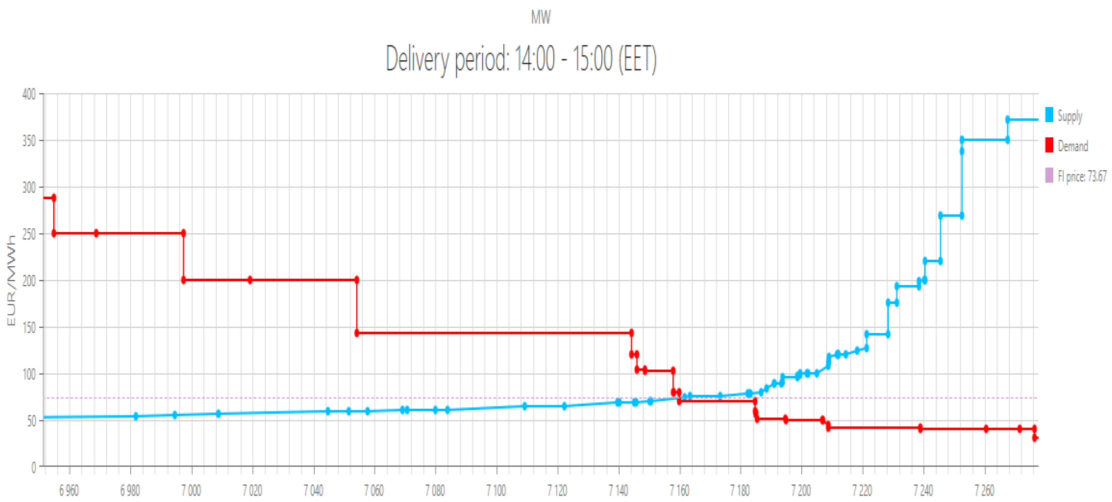
This chapter first explains how prices are determined in the day-ahead market, and how bottleneck situations affect prices in different countries and price areas. Then, the basic principles of the Nordic system and EPAD futures are explained. This includes a numeric example of the financial settlement of electricity futures. Literature review of previous studies regarding the relationship between spot and futures prices and futures risk premium concludes the chapter.

3.1 Nord Pool day-ahead market

Nord Pool’s day-ahead market is a daily auction which is performed for all Nordic and Baltic countries simultaneously. Based on the placed sale and purchase offers, Nord Pool’s EUPHEMIA algorithm calculates Nordic price for each individual hour of the following day. This pricing method is called marginal pricing, and the price for the whole Nordic area is called the system (spot) price. The deadline for leaving offers in daily auction is at 12:00 CET time, and the following day prices are typically published at ~13:00 CET time. The calculated Nordic system price doesn’t consider restrictions in transmission capacity across the Nordics. Therefore, the Nordic system price is the price that would have been achieved if there were only one bidding area and limitless transmission capacity within it. Obviously, this is not the case in reality as transmission capacity is limited, and there might be other technical limitations within the electricity grid. (Nord Pool, 2025a).

System price's significance is that it acts as underlying reference price for system futures that are in the delivery. For electricity futures, delivery means the selected period in which futures product is settled against the average system price. For example, it can be specific month, quarter, or year.

In the Nord Pool's daily auction, all the placed sale and purchase bids create an aggregated supply and demand curves. Electricity is no different than any other goods or services in a market economy, as in the end, the laws of supply and demand determine market prices. The price for each hour is determined by the intersection where supply and demand curves meet. Picture 2 provides an example of aggregated supply and demand curves for Finnish price area on March 12th, 2024, at 14:00-15:00. In this example, price is cleared at 73,67 €/MWh.



Picture 2. Aggregated demand and supply curves in the day-ahead market, Finnish price area 12.3.2024: 14:00-15:00 (Nord Pool, 2024).

The merit order of production methods is seen in picture 2. This means that in the supply curve, technologies that have low variable production cost such as wind, solar, hydro, and nuclear are offered to the market at low prices. In this example, all production up to 7000 MW is offered to the market with prices below ~55 €/MWh. As production methods with higher variable costs enter the market, the supply curve starts to increase gradually up to 400 €/MWh price level. On the demand curve, there is some price dependent flexibility when price levels get high. This can be seen as large gradual drops in the demand curve e.g. price drops from 200 €/MWh to 150 €/MWh at 7050 MW level. Respectively, when the price level is low, there is very little flexibility on the demand side, and therefore the demand curve gets almost transverse.

The descriptive version of the merit order is presented in figure 2. The final accepted supply offer to meet demand is called the marginal price which is paid to all accepted supply offers in the Nord Pool's auction. Marginal pricing ensures efficient pricing from an electricity user standpoint and means that most electricity producers earn more than their variable production cost. Producer's profit is determined by the difference between the market price and producers' production and capital cost. The marginal pricing method acts as an incentive for producers to offer their production to the market at the lowest possible price as otherwise their offers might not be accepted. For wind turbines and solar power plants, most of the total cost included these projects come upfront from the generating equipment and installation. The advantage of solar and wind power is low operating cost, whereas operating costs for fossil generators are very much dependent on fuel prices and emission allowance price. Fossil generators and nuclear producers must also consider starting up and shutting down costs in their pricing, which is not the case for wind and solar as their production is based on weather conditions. Due to these previously mentioned reasons, renewable production methods are typically offered to the market at very low prices. Although marginal pricing keeps spot prices as low as possible in the long run, the negative part of this pricing model is that it may lead to significant price spikes if e.g. demand is peaking due to weather conditions, some baseload nuclear is missing from the market due to maintenance, fuel prices are expensive, and renewable generation is at low level. (Jablonska et al., 2012; Energy Traders Europe, 2022)

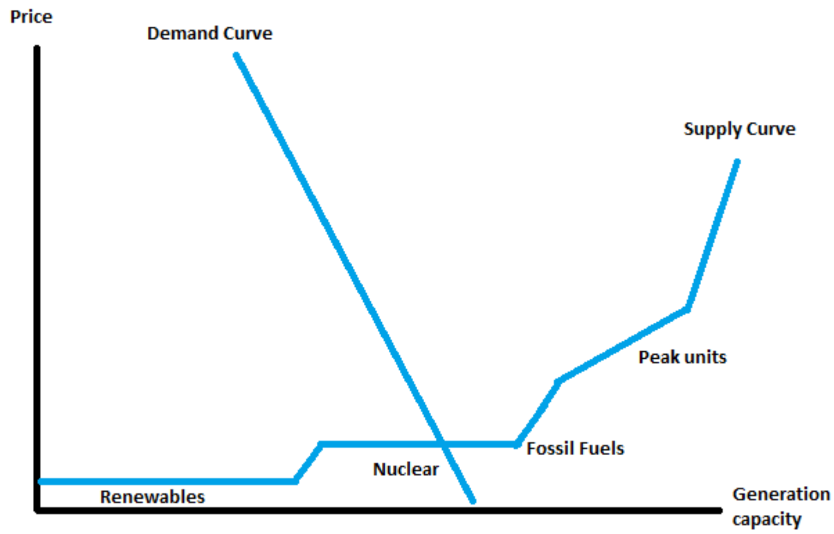


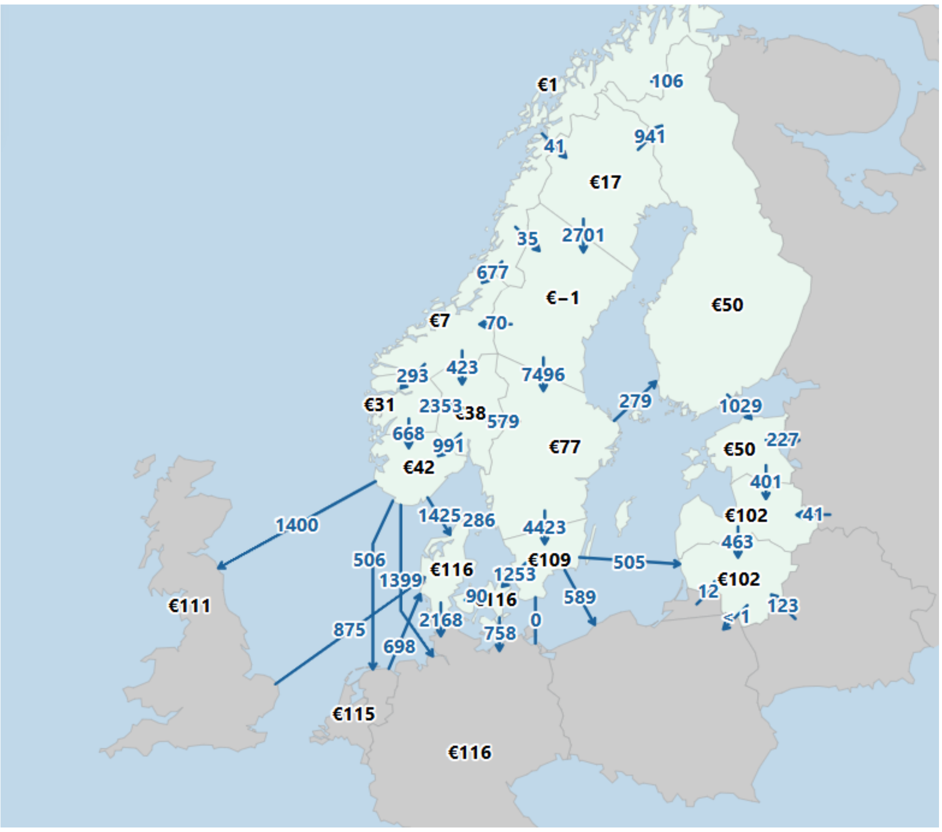
Figure 2. Marginal pricing and merit order of electricity production (adapted from Energy Trades Europe, 2022).

Electricity as a tradable commodity is unique because demand and supply must always be in balance to maintain ~50 Hz frequency in the grid. Although battery technologies have developed in recent years, and in theory, large scale batteries can be used to balance hourly variations between demand and supply. However, the storage capacity for batteries in the Nordics is currently limited. Also, the demand for electricity is not stable throughout the year in the Nordics as demand is much higher in winter months when electricity is used for e.g. heating households directly and for district heating via electric boilers. Winter demand for electricity in Finland can be twice as large compared to summertime. The supply side consists of various power plants, and some plants such as wind, solar and hydro are dependent on weather conditions. Also, power plant and interconnector failures happen from time to time, and in worst case repairs might take several months. For example, the repairs to the 650 MW Estlink 2 interconnector between Finland and Estonia took roughly 7 months in 2024 (Fingrid, 2024a).

In addition to seasonal demand and fragmented production mix, there are limitations in transmission grid between countries and price areas which causes so called “bottleneck” situations. For these previously mentioned reasons, spot prices tend to be volatile as weather conditions might change significantly day-to-day, or unexpected technical problems might limit e.g. nuclear or CHP (Combined Heat and Power) production. Market volatility has increased in recent years as more and more renewable production enters the grid and replaces old and predictable fossil production. For example, wind power capacity in Finland increased from 2268 MW in 2021 up to 6715 MW in the end of 2023 (Fingrid, 2024b).

As previously mentioned, the system price is a theoretical average price for the entire Nord Pool market area. However, transmission capacity in the Nordics is not often sufficient to reach full price convergence across the market area. Due to limitations of interconnectors, Nord Pool's market area is divided into several price areas. Finland is its own price area, but for example Sweden is divided into 4 price areas in a north-south direction, and Norway is divided into 5 price areas. Denmark has two price areas, and Baltic countries each have their own price area. Offers made in the day-ahead auction are specific to certain price areas, and therefore Nord Pool calculates spot prices separately for each individual area. The underlying key principle in the area price calculation is that the flow of electricity is always from the low-price area to the high price area. If the capacity is sufficient between the two areas, prices in low and high areas will merge with each other, which leads to the same price for both areas. If the capacity is not sufficient, meaning there's a bottleneck situation, the price in low area will increase and in high area decrease but prices will not merge at the same level. (Nord Pool 2025a).

Picture 3 exhibits how transmission cables connect different price areas, and how Nord Pool is connected to other neighboring power markets such as Germany, Netherlands and Great Britain.



Picture 3: Nord Pool price areas and transmission cables (Svenska Kraftnät, 2025).

3.2 Nordic system futures

In the financial market for electricity, future prices are the market's expectations of the average spot-prices for specific periods of time (week, month, quarter, and year). If market participants expect that the spot price will get higher in the future, this increases demand for system futures and therefore price increases. In reverse, if the spot price is expected to drop, futures prices decrease as well. Electricity futures are baseload products, meaning that the volume delivered (specified in MW) is the same for each hour of delivery period. Obviously in the real world, hardly any electricity consumer has constantly stable consumption throughout the day or longer periods of time, and therefore system futures don't hedge against consumption's profile risk. The same applies to energy producers as their production rarely is completely stable due to e.g. weather conditions, and annual or unplanned maintenance. Mathematically profile risk can be defined as the difference between consumption weighted spot price and arithmetic average of the spot price.

Instead of physical delivery, electricity futures are settled financially against delivered system spot-price. It is known that historically key factors influencing long-term futures prices in the Nordics include: development of hydroelectric balance and nuclear production, fuel (specifically gas and coal) and emission allowance prices, power prices in neighboring markets if the hydro balance is weak, the growth of wind and solar power, and expected overall demand for electricity. Hydropower covers roughly half of the total production in the Nordics in a year with normal rainfall. When the supply of hydro power is at a low-level Nordic system prices typically link closer to corresponding Central European prices. Respectively, strong hydro balance leads to much lower prices in the Nordics compared to Central European prices. (Energiateollisuus, 2024).

3.3 EPAD futures

As mentioned earlier, limitations in transmission capacity and imbalances between production and consumption in the different price areas may lead to situations where spot prices in different areas are higher or lower compared to the Nordic system price. Nordic system futures do not cover this so-called area price risk since they are settled against system price. In some cases, area prices may differ significantly from system spot prices. For example, in November 2022 spot price in Finland was delivered 86,09 €/MWh above the system price on average. Comparably, in March of 2022 Finnish spot was delivered 58,33 €/MWh below the average system price.

Market participants may use EPAD products to hedge against this area specific risk. EPAD refers to Electricity Price Area Difference. These products have also been called CFD's (Contract For Difference) in the past. Similarly to system futures, EPAD's are baseload products that are settled financially. The market price of an EPAD product reflects the market's expectation of the difference between area and system price for specific time period. This period can be either be week, month, quarter, or whole year. If a market participant e.g. large electricity consumer in Finland wants to hedge their consumption for both system and area price risks, they can purchase both system and EPAD futures which then creates synthetical contract that is settled against Finnish area price. In this case hedged system and EPAD periods and volumes need to be exactly the same. If EPAD's trade at a positive price, market expects that spot price in specific area will be higher than system price on average. If EPAD's are negative, then the market expects spot to be lower than the system price on average. Negative EPAD prices are typical for price areas that have a significant amount of surplus production. Respectively, high positive EPAD prices are common for areas that have deficient domestic production and therefore are more dependent on imported electricity.

Example of financial settlement for combined SYS+EPAD hedge: Market participant has bought 1,5 MW of ENOYR-21 product at 42 €/MWh, and 1,5 MW of SYHELYR-21 at 4,25 €. Since hedged volume is the same for both products, this is a synthetic future product for Finnish price area. Let's say that in year 2021 spot price in Finland is delivered at 52 €/MWh on average. In this case payoff ($S_T - K$) of future's position would be: 52 €/MWh – (42 €/MWh + 4,25 €/MWh) = 5,75 €/MWh. The delivery period for YR product is each hour of the whole calendar year 2021, and therefore the total financial settlement in this example would be 5,75 €/MWh * (1,5 MW* 24 h * 365 d) = 75 555€. If the hedged volumes were not exactly the same, this would lead to separate settlements for SYS and EPAD futures.

3.4 Literature review on futures-spot relationship and risk premium

Futures-spot relationship and risk premium of electricity has been studied comprehensively by e.g., Mork (2008), Haugom et al. (2017), Botterud et al. (2009), Huisman & Kilic (2012). Key findings of these papers are reported in this chapter. In this thesis, positive risk premium refers to futures prices exceeding realized spot price, and negative premium refers to the opposite.

Mork (2008) studied the development of risk premium in the Nordic electricity market in the period 1997 – 2004. In the research, the examination period is divided into 3 different subcategories: time before speculative trading, years when speculators such as Enron were active members in the market, and time after speculators left the market. According to research, there was a significant positive premium in monthly system futures prices before speculators entered the market, and premiums decreased closer to zero when outside speculators traded actively in the market. However, premium did not increase to back pre-speculators levels after speculative participants left the market, meaning that the market became more efficient due to outside speculators that did not own physical production assets but were active traders in the financial market.

Haugom et al. (2018) studied weekly system futures in the period 2004 – 2013 and found significant positive premiums in futures contracts 1 – 4 weeks ahead. Due to more uncertainty, risk premiums increased as the time to the beginning of delivery period increased, meaning that premiums were higher for e.g. 4 weeks ahead futures compared to the following week. Also, they provide some evidence regarding the seasonality of risk premium as premium levels were higher during winter and fall months compared to spring and summer months. Additionally, they studied which explanatory variables explain the future's premium. Studied variables included Nordic consumption, water inflow deviation from historical normal, wind production, hydro reservoir level deviation from historical normal, and variance of spot prices. According to the research, the deviation of water inflow is the most important determinant of futures premium. Also, level of hydro reservoir has positive effect on futures premium. The authors argue that this is somewhat surprising as one could assume that higher reservoir level compared to normal would lead to lower futures prices, and therefore decreasing risk premium. However, higher hydro reservoirs levels typically decrease the underlying spot prices which results in a positive impact for risk premium. Haugom et al. (2018) also report that high spot price variance in the trading week causes higher risk premium for short-term futures. Botterud et al. (2009) found similar results as Haugom et al. (2018) as they also found that weekly futures prices exceeded corresponding spot prices in period 1996 –

2006. They argue that risk preference differences between supply and demand sides is at least partly explaining why futures risk premium exists. On the supply side, hydro producers can relatively easily control their production. Hydro producers can store water and limit their offering to the spot market if it is expected that spot will be low and wait for higher price levels. However, this is not the case in “use-it-or-lose-it” situation if the hydro reservoirs are already almost full. Since hydro producers can optimize their short-term production, it does not make sense to fully hedge their production. On the demand side, electricity retailers and large industrial consumers typically cannot drastically change their consumption on short notice, and therefore it makes sense to hedge as much as possible.

Huisman & Kilic (2012) examined whether monthly (1 - 6 months ahead) futures prices include risk premium in the Dutch and the Nordic market. The price data was collected from April 2005 to December 2010. In the research, the authors characterize the Dutch market as perfect indirect storability market since most of electricity is produced by natural gas which can be stored. Respectively, the Nordic market is characterized as imperfect indirect storability because half of the total production is hydro based which is storable to some extent, but the other half is produced by other sources e.g. wind, solar and nuclear that are not storable. They conclude that in the natural gas based Dutch market there is time varying risk premium for monthly futures. Interestingly, they do not find time varying risk premiums in the Nordic market, but they point out that futures prices contain information about expected spot prices changes.

4 Data and descriptive statistics

This chapter first explains how the data is collected, and what different terminology used in this thesis means. Then, the chapter provides descriptive statistics of the future's price data and presents monthly average prices with figures. During the examination period of this thesis (2018- 2023), Europe experienced an energy crisis which led to a significant and rapid increase in the future markets. This chapter shortly discusses what were the underlying factors why prices rocketed to unprecedented levels. Also, chapter acknowledges changes in the fundamental price drivers in the Finnish EPAD market as Olkiluoto 3 nuclear power plant and new wind power plants have increased production capacity significantly in Finland.

4.1 Futures price data

Futures price data consists of a total of 1565 daily closing prices. Data is collected from period 1.1.2018 – 29.12.2023. Electricity futures are not traded on weekends and Norwegian national holidays. SYS front year 1 refers to the closest tradable system YR product in the Nasdaq financial market. For example, during calendar year 2019, ENOYR-20 is the front year 1 product, and as year changes over to 2020, ENOYR-21 becomes the front year 1 product and so forth. Front year 2 refers to the second closest YR product, e.g. during 2019, ENOYR-21 is the front year 2 product.

SYS+EPAD front year 1 combines daily closing prices of SYS+EPAD products. EPAD products are always specific to a certain price area. In this thesis, EPAD's prices are collected from Finnish, also known as Helsinki or SYHEL price area. To summarize, SYS+EPAD refers to a synthetic futures product that would be settled against Finnish area spot price. All the futures price data is collected from SKM Market Predictor Online service.

4.2 Descriptive statistics

Table 2 shows descriptive statistics for the selected future products. Average prices and standard deviations are higher for both SYS and SYS+EPAD front year 1 products compared to corresponding front year 2 products. For SYS products, the average difference between the front year 1 and 2 is 10,29 €/MWh. Respectively, the same difference is 15,64 €/MWh for SYS+EPAD products. Average prices and standard deviations are presented in table 2.

Table 2. Average prices and standard deviations of futures products (€/MWh).

Product	Average €/MWh	Standard deviation €/MWh
SYS Front Year 1	49,51	36,47
SYS+EPAD Front Year 1	58,61	42,41
SYS Front Year 2	39,22	17,15
SYS+EPAD Front Year 2	42,97	16,36

The difference in average prices and standard deviations between the front year 1 and 2 mainly comes from the energy crisis that Europe experienced in 2022. From the beginning of 2018 to May 2022, SYS front year 1 and 2 were traded at levels close to each other (see figure 3). In the summer of 2022, an energy crisis hit Europe which increased front year 1 price to record high levels (+250 €/MWh). The price of SYS front year 2 also increased rapidly but the price peak was much lower (+150 €/MWh) compared to front year 1, and it lasted for a much shorter period. Both price levels were unprecedented compared to what had previously been considered as a high price level for the front year 1 and 2 products. Price development of SYS front year 1 and 2 futures is presented in figure 3.

The energy crisis started off in Central Europe and spread to the Nordic countries through transmission cables. After Russia attacked Ukraine, Russian pipeline gas supplies to Europe dropped significantly which in sequence significantly raised the price of natural gas. Unlike in the Nordic countries, fossil fuels are still a significant part of the electricity production mix in Central Europe, and therefore the price of electricity correlates strongly with the marginal production cost of natural gas or coal. To give some perspective on the importance of natural gas, roughly 20% of all electricity in the EU was produced with natural gas back in 2022. Several transmission cables connect the Nordic countries to Central Europe which is why the prices in the Nordic countries are partly coupled with the prices in Central Europe. Price coupling to Central Europe is typically stronger if the hydro balance in the Nordic countries is at a low level which was precisely the situation in the summer of 2022. SKM Market Predictor estimated that Nordic hydro balance was ~10 TWh below normal level in the summer of 2022. To give some context of historical variation, Nordic hydro balance can vary between -25 TWh and +25 TWh from the seasonal normal. If the hydro balance had been better in the Nordics, it would have been likely that spot and future prices had not reached as elevated levels as they did. Also, European nuclear power production was weak at that time as several nuclear power plants in France were under annual maintenance or could not be operated at full capacity due to hot temperatures as nuclear reactors use water from the surrounding rivers to cool the reactor. Due to regulations, nuclear power plants may need to reduce their output if water temperatures get too high in order to avoid thermal pollution. In addition to weak hydro balance and expensive production cost of fossil fuels, shortage in European nuclear production also contributed to high future prices in the Nordics. (Energiateollisuus, 2023).

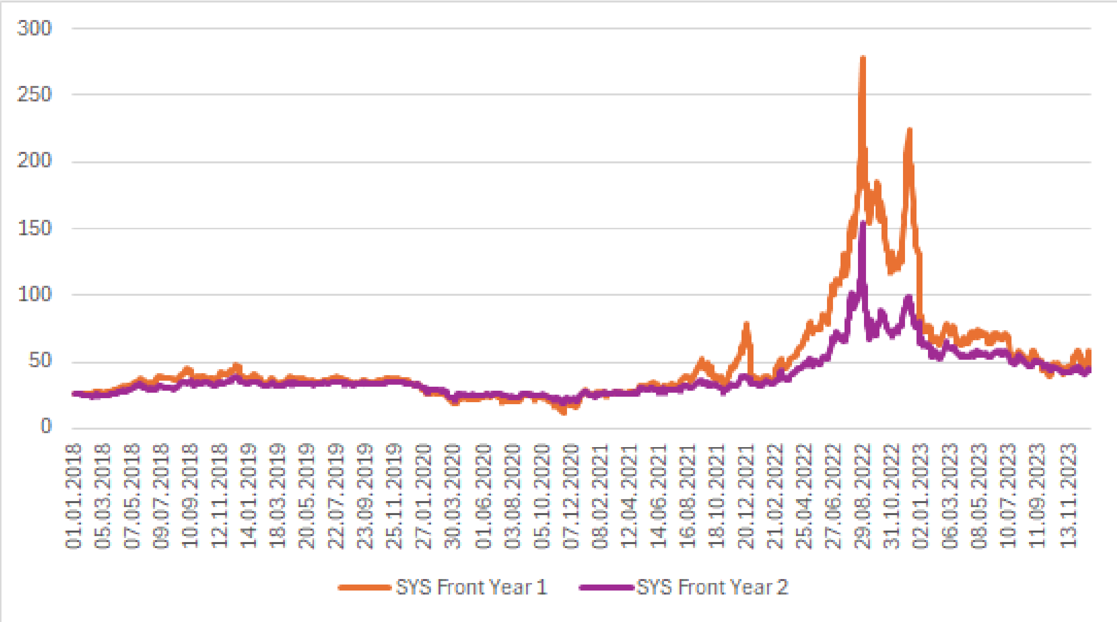


Figure 3. SYS front year 1 & 2 prices 2018-2023 (€/MWh).

When comparing SYS+EPAD prices to SYS prices, it easy to notice that SYS+EPAD prices have been traded on a higher level on average compared to just SYS products (+9,10 €/MWh on average for front year 1, and +3,75 €/MWh for front year 2). This means that Finnish EPAD prices have been positive on average from 2018 to 2023. However, it's worth mentioning that during the period 2018-2023, the market has also seen negative EPAD prices for the Finnish price area: - 9,25 €/MWh for front year 1 at the lowest, and - 6,88 €/MWh for front year 2. Negative EPAD prices occurred after the commission of Olkiluoto 3 nuclear power plant in April of 2023. Olkiluoto 3 increased nuclear capacity in Finland by 1600 megawatts (from 2794 MW to 4394 MW). In addition to new nuclear capacity, wind power in Finland also increased rapidly in the years 2021-2023. According to Fingrid's open data service, wind capacity in Finland was at 2268 MW in the beginning of 2021, and by the end of 2023 installed capacity had increased up to 6715 MW. However, when comparing the growth of nuclear and wind power in MW capacity, it is essential to remember that nuclear power has a much higher capacity factor compared to wind power. In Finland, wind power's annual average of capacity factor has been around 30% according to Fingrid's open data service. The peak of negative EPAD prices happened right after the commission of Olkiluoto 3 in May-July 2023. However, negative

EPAD prices only lasted for a relatively brief period, and then Finnish EPAD prices increased back to the positive side.

In this thesis, the objective is to examine seasonal prices changes of SYS and SYS+EPAD futures. For this purpose, future price data is divided into 12 monthly groups based on the trading month (group 1 is January, group 2 is February, group 3 is March, and so forth). After data is divided into groups, average prices are calculated for each month. Results are reported in table 3. Prices in the 3 lowest months are marked with *, and respectively 3 highest months are marked with **.

Table 3. Average market prices in different months (€/MWh).

Month	SYS Front Year 1	SYS Front Year 2	SYS+EPAD Front Year 1	SYS+EPAD Front Year 2
1	38,77*	35,27	45,41	39,63
2	37,46*	34,16*	43,65*	38,32*
3	38,93*	34,88*	44,24*	38,34*
4	40,80	35,02*	44,61*	38,40*
5	45,35	37,53	48,31	39,88
6	48,11	38,41	53,49	41,29
7	50,33	39,87	59,83	43,30
8	63,04**	44,29**	72,83**	49,85**
9	61,57**	45,22**	71,63**	45,92
10	53,00	41,52	67,36	45,54
11	53,94	39,70	71,22	46,07**
12	61,97**	43,12**	79,65**	48,71**

*Denotes one of three lowest price months
** Denotes one of three highest price months

As seen in table 3, SYS front year 1 and 2 products tend to be at the lowest at the beginning of the year (from January to April). Highest prices are typically observed around August-September and November-December periods. By a visual inspection, seasonal price patterns for SYS front year 1 and 2 are clearly similar in shape, but price levels are different as front year 1 stays on a higher level throughout the price curve.

Also, it’s noteworthy that during peak price months (e.g. August-September or November-December) the difference between SYS front year 1 and 2 is larger compared to low price months (e.g. February-March). To give an example, in February (low price month) the difference is 2,58 €/MWh on average, and in September (high price month) the difference is 16,35 €/MWh on average. This indicates that market uncertainty or changes in fundamental price drivers have less impact on SYS front year 2 futures compared to SYS front year 1 futures.

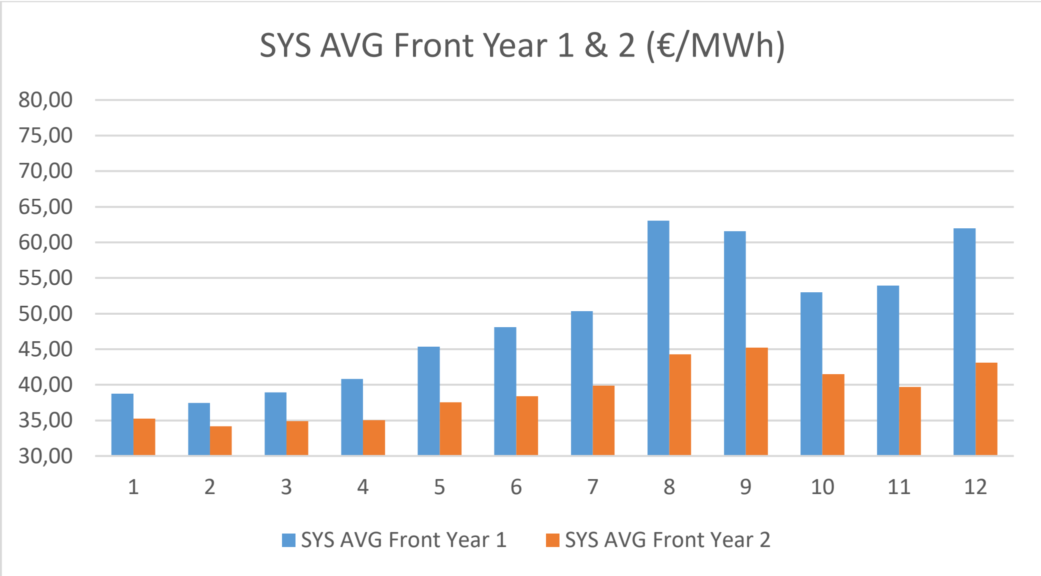


Figure 4. SYS Front Year 1 & 2 monthly average prices 2018-2023 (€/MWh).

Similar to SYS price patterns, SYS+EPAD prices were lowest in the beginning of the year (February – April). The highest average prices occurred in the later parts of the year (August – September and November - December). When comparing SYS+EPAD front year 1 and 2 products, the difference between low and high price months is larger in both cases compared to SYS products. For example, in February the difference between SYS+EPAD front year 1 and 2 is only 5,33 €/MWh, but the difference increases up to 25,71 €/MWh by September. Average monthly prices of SYS+EPAD products are presented in figure 5.

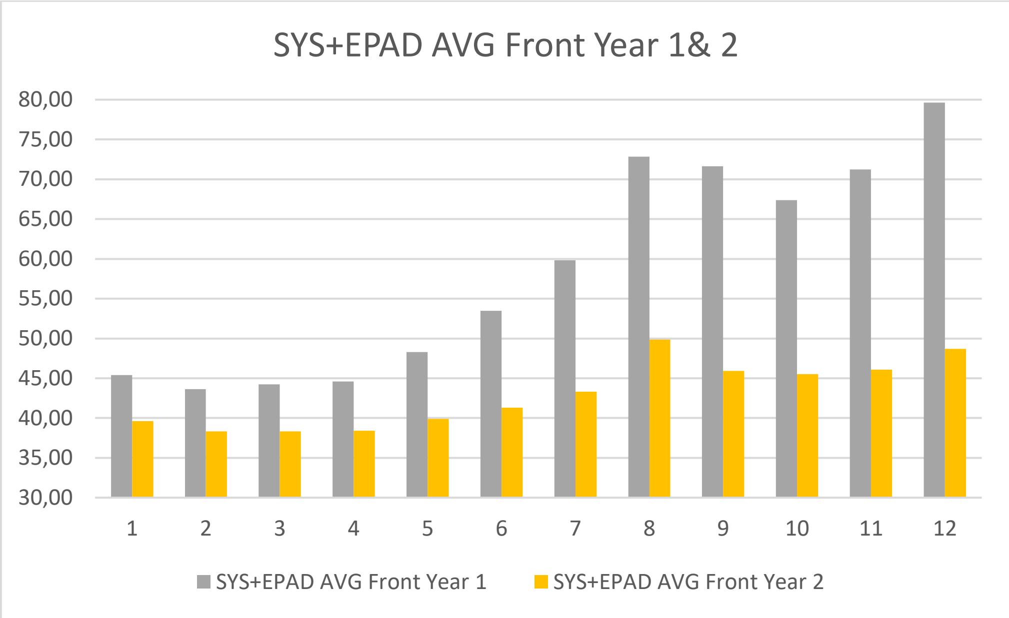


Figure 5. SYS+EPAD Front Year 1 & 2 monthly average prices 2018-2023 (€/MWh)**.**

Figure 6 presents monthly averages of EPAD prices from 2018 to 2023. Monthly EPAD prices have been fairly stable from January to July with prices varying around 2,5 – 6,5 €/MWh. However, it is noticeable that front year 1 EPAD starts to increase in July, and by the last quarter of the year the price has reached above 14 €/MWh level on average. This could indicate that Finnish area price risk has often been underestimated in early months of the year by the market participants, or alternatively, EPAD's have become overpriced late in the year as the upcoming winter period (next year's January-March) is approaching. Junttila, Myllymäki, & Raatikainen (2018) studied risk premiums of monthly Finnish EPAD's from 2006 – 2016. They found that there has been positive risk premium in Finnish EPAD prices, and it has been highest during autumn and wintertime. Increase in risk premium could also explain why EPAD prices tend to increase after the summer.

Spodniak & Collan (2015) studied risk premiums for several different price areas in the Nordics. They argue that the negative risk premiums are related to electricity producers being more risk-averse in the typically export-oriented price areas e.g. northern price areas of Sweden. In the import-oriented price areas like Finland or Baltic countries, retailers and industrial consumers are typically more risk-averse which then creates more hedging pressure, and this leads to positive risk premiums for EPAD's. To summarize, front year 1 EPAD prices tend to start increasing after the summer whereas front year 2 EPAD's stay at a relatively stable level throughout the entire year. The increase in front year 1 EPAD prices may result from higher risk premiums late in the year, lack of selling interest in the EPAD market, or area price risk being underestimated in the early months of the year. A more detailed analysis of this is left for further research.

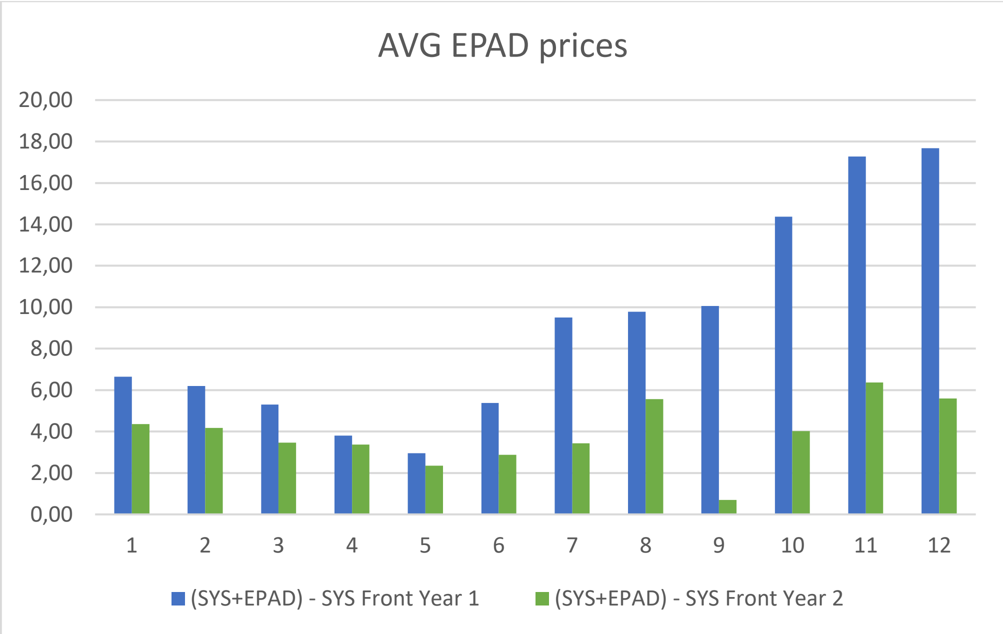


Figure 6. Monthly averages of EPAD prices 2018-2023 (€/MWh).

5 Empirical findings

This chapter presents empirical findings of the thesis and draws conclusion whether the hypotheses are accepted or rejected. This is done in two phases. First, by utilizing non-parametric tests, and secondly applying the findings of these tests to the capital asset pricing model. For hypothesis 1 and 2, non-parametric tests are used to examine whether some months are systematically traded at lower or higher levels than others. Also, it's examined how adding EPAD component on top of the traditional system future affects the time seasonality, and how time seasonality changes with products that have different delivery periods (front year 1 vs front year 2).

To examine hypotheses 3, the findings of non-parametric tests are then applied to the capital asset pricing model. Practically, this means forming a trading strategy that buys electricity futures in low price months and then sells the same futures position away in a high price month. This same strategy is then repeated over several years. This "time seasonality-based" trading strategy is lastly benchmarked against the market portfolio. Finding a proxy for the market portfolio of electricity futures is a challenging task as there aren't obvious choices that would reflect electricity market perfectly. Previous studies such as Størdal et al. (2023) have used OMX Nordic 40 and German DAX indexes as proxies for Nordic and German electricity markets. However, both OMX Nordic 40 and DAX can be described as general market indexes that are not specific to the energy sector. In this thesis, Nasdaq OMX Nordic Energy Net Index (presented in figure 7) is selected as proxy for market portfolio as it consists of energy sector companies that, at least to some degree, are dependent on electricity futures prices. To simplify the analysis of the selected trading strategy, it is assumed that there aren't any transaction costs and there's enough cash to cover all possible margin calls resulting from daily mark-to-market accounting. Similar to Størdal et al. (2023), 3-month Euribor is selected as risk-free rate. OMX Nordic Energy Net Index data is collected from the Nasdaq's webpage, and Euribor data is collected from the Bank of Finland's webpage.

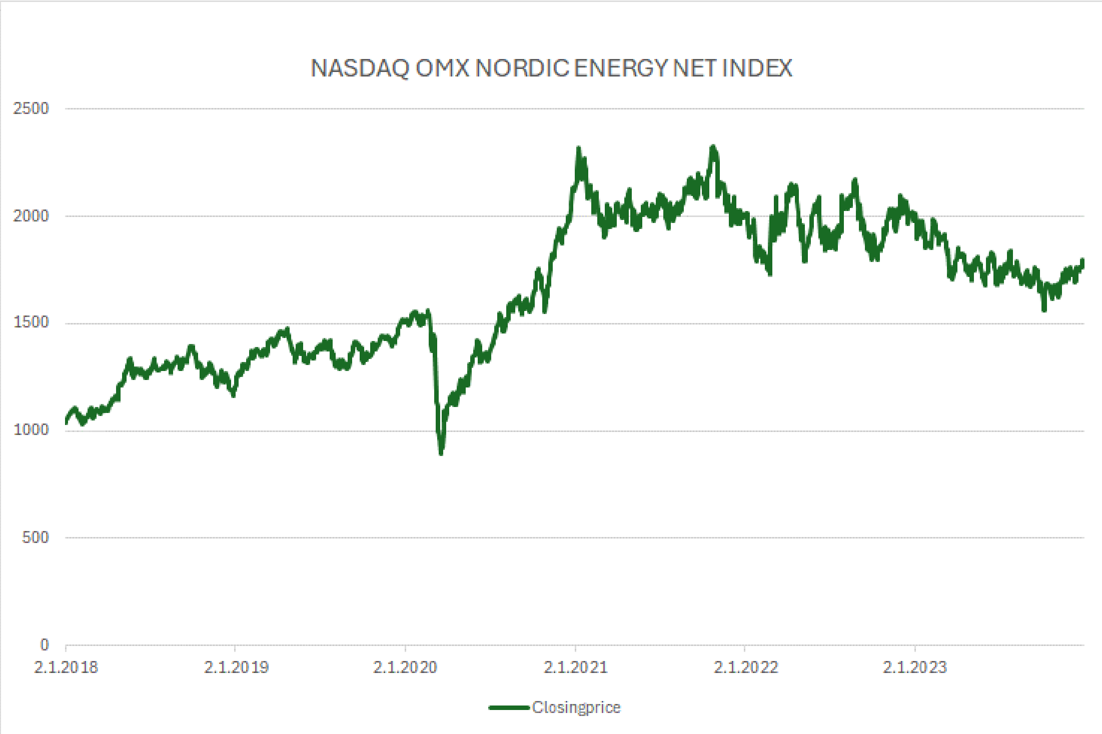


Figure 7. Nasdaq OMX Nordic Energy Net Index.

As a recap from the introduction, the hypotheses are the following:

Hypotheses 1: There is more time seasonality found in SYS+EPAD products compared to SYS products.

The underlying premise for this hypothesis is that there's lack of natural sellers in the Finnish EPAD market. Lack of sellers combined with Finland's dependency on the imported electricity during peak consumption periods, and high variance of renewable energy production causes a higher area-specific price risk. Due to higher risk, it's expected that time seasonality is more pronounced for synthetic SYS+EPAD front 1 and 2 futures compared to corresponding SYS futures.

Hypotheses 2: Time seasonality effect is stronger in front year 1 products compared to front year 2 products.

It's expected that changes in the fundamental price drivers in the electricity markets such as hydrological balance, fuel prices, nuclear output, growth of renewable production, electricity consumption, and available transmission capacity will have a greater impact on the front year 1 futures as they are closer to the beginning of delivery period compared to front year 2 futures.

Hypotheses 3: Trading time seasonality of SYS+EPAD products will generate more positive alpha than SYS products in the context of capital asset pricing model.

The EPAD market lacks liquidity due to e.g., asymmetric power balances, high collateral costs, and growth of bilateral and long-term PPA contracts. Due to these previously mentioned reasons, it is expected that Finnish EPAD market is inefficient, and this market inefficiency can be exploited even with a simple trading strategy such as "buy low price months and sell away high price months". This hypothesis is based on the findings of previous studies such as Størdal et al. (2023) and Ewald et al. (2022) which both have found that trading time seasonality can generate positive and statistically significant excess returns for both Nordic and German electricity futures, Henry Hub natural gas futures, and WTI crude oil futures. It is expected that combining system future with Finnish EPAD future results in even higher excess returns.

5.1 Non-parametric tests

Kruskall-Wallis (1952) is a non-parametric test used to determine whether two or more groups originate from the same distribution. In this case we have twelve groups as there are twelve months in a year. Kruskall-Wallis is a non-parametric test meaning that there isn't any distribution assumption such as normal distribution. In the Kruskall-Wallis test, the data sample is assumed to take similar distribution across all groups, meaning that low and high rank daily prices should be equally distributed for all groups. Kruskal-Wallis formula is defined as in equation 12:

$$H = \frac{n-1}{n}\sum_{i=1}^{k}\frac{n_i\,(\bar{R} - E_R)^2}{\sigma^2} \tag{12}$$

where n is total sample size, n_i is number of observations in group i, $\bar{R}$ is mean rank sum in group i, E_R is the expected value of the rankings, and σ^2 rank variance.

The null hypothesis (H0) for Kruskall-Wallis test is that group means are equal which would mean that there isn't statistically significant difference between different groups in the selected period 2018 - 2023. Alternative hypothesis (H1) is that groups are not equal. Results of the Kruskall-Wallis test are reported in table 4.

The null hypothesis is rejected or all products with 1% significance level, and thus alternative hypothesis is accepted. This means that at least one group differs statistically from other groups, and we can argue that there is some seasonality related to the trading month in the sample of 2018 - 2023. However, Kruskal-Wallis doesn't indicate which month, or months are stochastically dominating others, but it provides a starting point for further analysis. Dunn's pairwise comparison is conducted next to get better understanding of which month or months are dominating stochastically others.

Table 4. Results of Kruskal-Wallis test.

Product	Sample size (N)	Chi square (H)
SYS Front year 1	1565	73,39***
SYS+ EPAD Front year 1	1565	215,67***
SYS Front year 2	1565	63,89***
SYS+ EPAD Front year 2	1565	152,57***

*** denotes 1% significance level

Dunn's test is used to pinpoint which groups are significantly different from others. Test is completed for all possible group combinations (1-2, 1-3, 1-4,…). Since there are a total of 12 groups, this means a total of 66 pairwise combinations for all four products. Results are reported in tables 5 through 8.

In Dunn's (1964) test, when comparing e.g. groups A and B from same data, z-value is calculated with the following equation (13):

$$z_i = \frac{\overline{W_A} - \overline{W_B}}{\sigma_i} \tag{13}$$

where $\overline{W_A} - \overline{W_B}$ is the difference of mean rank sums between groups A and B. Standard error is calculated as below in equation 14:

$$\sigma_i = \sqrt{\left(\frac{N(N+1)}{12} - \frac{\sum_{s=1}^{r} T_s^3 - T_s}{12(N-1)}\right)\left(\frac{1}{n_A} + \frac{1}{n_B}\right)} \tag{14}$$

where N is total number of all observations, r is the number of tied ranks, and T_s is the number of observations at the tied ranks, n_A is the number of observations in group A, and n_B is the number of observations in group B.

In Dunn's test, larger z-statistics (further away from zero) indicates a larger difference between the groups. As seen in the tables from 5 to 8, the largest z-values are typically found between groups 2-4 (February – April) and 8-9 (August – September), and groups 2-4 (February – April) and 11-12 (November - December). We can also see that z-statistics are systematically higher for SYS+EPAD front year 1 compared to SYS front year 1. The same applies to SYS+EPAD front year 2 and SYS front year 2. Therefore, we can confirm hypotheses 1 as it's evident that more time seasonality is found in synthetic SYS+EPAD futures compared to SYS futures.

Z-statistics are somewhat higher for SYS+EPAD front year 1 compared to SYS+EPAD front year 2. However, there isn't much of a difference in z-statistics when comparing SYS front

1 to SYS front year 2. This means that we can partially confirm hypotheses 2 that time seasonality is stronger for front year 1 futures compared to front year 2 futures as this is accurate for SYS+EPAD futures. However, for SYS futures hypothesis 2 is rejected.

Table 5. Results of Dunn's pairwise monthly comparison - SYS front year 1.

Month	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	0,984	0,418	0,296	1,665	1,537	2,336	3,656	3,994	2,858	3,597	4,338
2		0,578	1,263	2,605	2,474	3,258	4,545	4,867	3,766	4,483	5,208
3			0,710	2,086	1,955	2,758	4,081	4,416	3,280	4,020	4,764
4				1,353	1,229	2,019	3,324	3,664	2,535	3,269	4,002
5					0,115	0,675	1,988	2,346	1,196	1,942	2,677
6						0,785	2,088	2,442	1,302	2,042	2,771
7							1,308	1,673	0,520	1,268	1,998
8								0,381	0,786	0,031	0,698
9									1,157	0,409	0,310
10										0,749	1,478
11											0,723

Month	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	0,325	0,676	0,767	0,096	0,124	0,019	0,000	0,000	0,004	0,000	0,000
2		0,563	0,207	0,009	0,013	0,001	0,000	0,000	0,000	0,000	0,000
3			0,477	0,037	0,051	0,006	0,000	0,000	0,001	0,000	0,000
4				0,176	0,219	0,044	0,001	0,000	0,011	0,001	0,000
5					0,908	0,500	0,047	0,019	0,232	0,052	0,007
6						0,433	0,037	0,015	0,193	0,041	0,006
7							0,191	0,094	0,603	0,205	0,046
8								0,703	0,432	0,976	0,485
9									0,247	0,683	0,757
10										0,454	0,139
11											0,470

Pairwise z-test statistics in the upper table, p-values in the lower table.

Table 6. Results of Dunn's pairwise monthly comparison - SYS+EPAD front year 1.

Month	2	3	4	5	6	7	8	9	10	11	12
1	1,075	0,710	0,579	1,179	1,653	2,721	4,661	6,134	5,909	6,472	7,419
2		0,385	0,501	2,223	2,678	3,724	5,616	7,042	6,829	7,374	8,300
3			0,123	1,891	2,361	3,435	5,381	6,848	6,629	7,190	8,142
4				1,747	2,212	3,273	5,196	6,649	6,430	6,986	7,926
5					0,483	1,544	3,480	4,966	4,732	5,300	6,243
6						1,050	2,969	4,450	4,214	4,779	5,713
7							1,926	3,427	3,182	3,754	4,689
8								1,529	1,268	1,850	2,781
9									0,270	0,311	1,226
10										0,585	1,508
11											0,917

	2	3	4	5	6	7	8	9	10	11	12
1	0,282	0,478	0,563	0,238	0,098	0,007	0,000	0,000	0,000	0,000	0,000
2		0,700	0,616	0,026	0,007	0,000	0,000	0,000	0,000	0,000	0,000
3			0,902	0,059	0,018	0,001	0,000	0,000	0,000	0,000	0,000
4				0,081	0,027	0,001	0,000	0,000	0,000	0,000	0,000
5					0,629	0,122	0,001	0,000	0,000	0,000	0,000
6						0,294	0,003	0,000	0,000	0,000	0,000
7							0,054	0,001	0,001	0,000	0,000
8								0,126	0,205	0,064	0,005
9									0,787	0,756	0,220
10										0,559	0,132
11											0,359

Pairwise z-test statistics in the upper table, p-values in the lower table.

Table 7. Results of Dunn's pairwise monthly comparison – SYS front year 2.

Month	2	3	4	5	6	7	8	9	10	11	12
1	0,917	0,868	0,056	1,230	1,442	1,889	2,845	3,707	2,425	2,664	4,204
2		0,073	0,854	2,115	2,316	2,755	3,689	4,521	3,277	3,508	5,011
3			0,804	2,100	2,306	2,758	3,719	4,573	3,296	3,532	5,078
4				1,274	1,484	1,926	2,873	3,727	2,457	2,694	4,220
5					0,222	0,661	1,612	2,489	1,197	1,441	2,976
6						0,435	1,378	2,251	0,967	1,210	2,733
7							0,947	1,830	0,535	0,781	2,311
8								0,897	0,410	0,159	1,373
9									1,299	1,047	0,464
10										0,248	1,776
11											1,521

	2	3	4	5	6	7	8	9	10	11	12
1	0,359	0,386	0,956	0,219	0,149	0,059	0,004	0,000	0,015	0,008	0,000
2		0,941	0,393	0,034	0,021	0,006	0,000	0,000	0,001	0,000	0,000
3			0,422	0,036	0,021	0,006	0,000	0,000	0,001	0,000	0,000
4				0,203	0,138	0,054	0,004	0,000	0,014	0,007	0,000
5					0,825	0,509	0,107	0,013	0,231	0,150	0,003
6						0,664	0,168	0,024	0,334	0,226	0,006
7							0,344	0,067	0,592	0,435	0,021
8								0,370	0,682	0,874	0,170
9									0,194	0,295	0,643
10										0,804	0,076
11											0,128

Pairwise z-test statistics in the upper table, p-values in the lower table.

Table 8. Results of Dunn's pairwise monthly comparison - SYS+EPAD front year 2.

Month	2	3	4	5	6	7	8	9	10	11	12
1	0,7208	0,8319	0,2239	1,3353	1,3179	1,9469	3,3163	5,4216	4,8845	4,9546	6,8079
2		0,0881	0,4960	2,0213	1,9996	2,6159	3,9518	5,9972	5,4774	5,5440	7,3509
3			0,5995	2,1697	2,1458	2,7808	4,1560	6,2553	5,7239	5,7909	7,6509
4				1,5464	1,5276	2,1518	3,5086	5,5922	5,0612	5,1302	6,9662
5					0,0072	0,6141	1,9785	4,0991	3,5518	3,6270	5,4751
6						0,6166	1,9705	4,0754	3,5318	3,6066	5,4405
7							1,3595	3,4833	2,9321	3,0096	4,8519
8								2,1472	1,5836	1,6665	3,5106
9									0,5738	0,4836	1,3311
10										0,0887	1,9198
11											1,8237

	2	3	4	5	6	7	8	9	10	11	12
1	0,471	0,405	0,823	0,182	0,188	0,052	0,001	0,000	0,000	0,000	0,000
2		0,930	0,620	0,043	0,046	0,009	0,000	0,000	0,000	0,000	0,000
3			0,549	0,030	0,032	0,005	0,000	0,000	0,000	0,000	0,000
4				0,122	0,127	0,031	0,000	0,000	0,000	0,000	0,000
5					0,994	0,539	0,048	0,000	0,000	0,000	0,000
6						0,537	0,049	0,000	0,000	0,000	0,000
7							0,174	0,000	0,003	0,003	0,000
8								0,032	0,113	0,096	0,000
9									0,566	0,629	0,183
10										0,929	0,055
11											0,068

Pairwise z-test statistics in the upper table, p-values in the lower table.

5.2 Time seasonality as a trading strategy

Based on the results of statistical tests, we have found out that largest differences are between groups 2-4 (February-April) and 8-9 (August-September), and 2-4 (February-April) and 11-12 (November-December). This means that both SYS and SYS+EPAD prices tend to be the lowest in the early months of the year and respectively tend to peak in autumn and right before the end of the year. Størdal et al. (2023) tested a trading strategy in which a long position was entered in February, and the position was closed in August. According to the research, this trading strategy has produced statistically significant alphas in the context of CAPM during examination period 2006 – 2021. In order to not test the same strategy as Størdal et al. (2023), it's selected that future's position is closed in the last two months of the year (November-December). Therefore, the following two trading strategies are created for all four products:

- Buy in April and sell away in November.
- Buy in March and sell away in December.

Both strategies are operating in an annual seasonal cycle, meaning that same long-short position is repeated over six years. In other words, there are only two trades made in a single year that are in the opposite direction. It's decided that possible annual profits are not reinvested, meaning that the amount invested per year stays the same over the whole trading period. The return (r_f) for is calculated as in equation 15:

$$r_f = \frac{(F^{t+1} - F^t)}{F^t} \tag{15}$$

Where F^t is the initial purchase price, and F^{t+1} is the futures price when the position is closed. The purchase price (F^t) is the average of daily closing prices in the month's first week, e.g. the average of closing prices in the first week of April. Respectively, when the position is closed, the sell-away price (F^{t+1}) is the average of daily closing prices in the last week of the month.

The results for both trading strategies are reported in table 9. On average, both strategies have been profitable and performed better than the selected market index (OMX Nordic Energy Net Index). This is also accurate even if the crisis year of 2022 is excluded from the sample. The energy crisis started in the summer of 2022 when Russian gas supplies to the Central-Europe were significantly reduced. The Nordic market is linked to Central-Europe through transmission cables, and for this reason high futures prices in Central-Europe were partly transmitted to the Nordics although only a small portion of all electricity is produced with natural gas in the Nordics. During that time, there were also other issues which also contributed to the energy crisis. For example, Nordic hydro balance was at low level, and all the French nuclear power plants were not operating at full capacity due to reactor cooling limitations caused by high river temperatures. After the initial crisis and unpresented futures price levels, the market slowly recovered, and futures prices decreased back to more normal levels. This led to both strategies being unprofitable in 2023.

From table 9 we can see that returns seem to fluctuate from year to year. Also, it is evident that both strategies have performed better for front year 1 futures compared to front year 2 futures. This is not surprising as fundamental price drivers tend to have a larger price impact on products that are closer to the beginning of the delivery period. Fundamental price drives can have either decreasing or increasing impact on prices, but the upside potential is much larger than downside as zero limits the potential for price declines in the long term. Electricity prices are often described as mean reverting. This means that prices tend to fluctuate around the long-term equilibrium level depending on the fundamental price drivers such as weather conditions, operational situation of power plants, hydro balance and fuel prices (Huisman & Mahieu, 2003). Due to mean reversion of future prices, it's expected that futures prices will revert to equilibrium level in the long run, and thus futures price volatility is typically lower for products that are more distant from the present moment e.g. front year 2 futures.

Another year that stands out is 2020 when both SYS front year 1 and 2 resulted in a loss but SYS+EPAD front year 1 and 2 gained positive returns. In other words, adding EPAD component on top of traditional SYS future made both trading strategies profitable. Overall, SYS+EPAD futures have performed better than SYS futures for both strategies. For example, buying SYS front year 1 futures in April and selling the position away in November profited 45 % on average. Respectively, buying SYS+EPAD front year 1 futures in April, and selling them away in November resulted in a profit of 69 % on average. SYS+EPAD front year 2 futures have also performed better than SYS front 2 futures, but the difference is much smaller compared to front year 1 futures. For example, buying in March and selling away in December strategy has gained 25 % on average for SYS+EPAD front year 2 futures, and 21 % on average for SYS font year 2 futures.

Table 9. Trading strategy and market portfolio returns.

Buy in April and sell away in November	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**AVG**
SYS Front Year 1	42 %	5 %	-12 %	79 %	177 %	-23 %	**45 %**
SYS+ EPAD Front Year 1	38 %	12 %	39 %	77 %	248 %	-3 %	**69 %**
SYS Front Year 2	30 %	4 %	-2 %	23 %	108 %	-19 %	**24 %**
SYS+EPAD Front Year 2	31 %	5 %	22 %	22 %	108 %	-17 %	**29 %**
OMX Nordic Energy Net Index	12 %	0 %	74 %	0 %	-2 %	-2 %	**14 %**
Buy in March and sell away in December	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**AVG**
SYS Front Year 1	41 %	-8 %	-28 %	176 %	184 %	-33 %	**55 %**
SYS+ EPAD Front Year 1	32 %	-3 %	20 %	172 %	232 %	-23 %	**72 %**
SYS Front Year 2	40 %	0 %	-23 %	45 %	94 %	-32 %	**21 %**
SYS+EPAD Front Year 2	32 %	3 %	12 %	42 %	91 %	-30 %	**25 %**
OMX Nordic Energy Net Index	9 %	10 %	44 %	3 %	4 %	-8 %	**10 %**

5.3 Regression results

Theoretical approach to capital asset pricing model was presented in chapter two of this thesis. As a recap, empirical model of CAPM can be defined as in equation 16:

$$r_i^t = \alpha_i + \beta_i^*\left(r_m^t - r_f^t\right) + \epsilon_i^t \tag{16}$$

Where r_i^t is the futures return in the time period t, $r_m^t - r_f^t$ is the market portfolios return over risk-free return in the same time period t, β_i^* (beta) measures the sensitivity of futures price change to the market portfolio, and α_i (alpha) captures the excess return generated by the trading strategy.

If selected trading strategy such as "Buy in April, sell in November" or "Buy in March, sell in December" is an arbitrage opportunity, then the trading strategy should be able to produce statistically significant and positive alphas. Results for the "Buy in April, sell in November" strategy are presented in table 10.

Table 10. CAPM regression parameters – Buy in April, Sell in November.

	$\boldsymbol{\alpha_i}$	$\boldsymbol{\beta_i^*}$	$\boldsymbol{R^2}$	**P-value (α_i)**	**P-value ($\boldsymbol{\beta_i^*}$)**
SYS Front Year 1	0,00883*	0,38362**	0,01995	0,07095	0,04387
SYS Front Year 2	0,00471	0,45908***	0,04771	0,20569	0,00170
SYS+EPAD Front Year 1	0,01291***	0,28841*	0,01733	0,00119	0,06053
SYS+EPAD Front Year 2	0,00580*	0,41721***	0,04771	0,08679	0,00170

*denotes 10% significance level, ** 5% significance level, and *** 1% significance level

All the products have a positive alpha ranging from 0,0047 to 0,0129. This provides some evidence that our selected strategy has indeed beaten the market in the examination period of 2018 - 2023. However, the alpha is statistically significant at 1% level for SYS+EPAD front year 1. For SYS front year 1 and SYS+EPAD front year 2 alpha is statistically significant at 10 % level. This means that results other than for SYS+EPAD front year 1 should be interpreted cautiously as they are only marginally significant or insignificant.

All the beta values are positive, which indicates that there is a direct relationship between the market index and futures price. For SYS Font Year 2 and SYS+EPAD front year 2 beta values are statistically significant at 1% level, for SYS front year 1 at 5 % level, and for SYS+EPAD front year 1 at 10 % level. However, beta value ranges from 0,288 to 0,459 which can be described as low or moderate. Also, R^2 values range from 0,017 to 0,048, which means that the market index explains only a small proportion of changes in the future's prices. Therefore, the beta and R^2 values show that the index is not a good indicator of future price movements on its own and other factors are likely to contribute more to the variability in the future's price.

To summarize, the "Buy in April, sell in November" strategy has been able to beat the market index to some extent, but the magnitude of alpha can be described as low for SYS front year 1 and SYS+EPAD front year 2 and moderate for SYS+EPAD front year 1.

Regression parameters for "Buy in March, sell in December" -strategy are presented in table 11. For this strategy, alphas are positive and statistically significant at 10 % level for SYS front year 1 and SYS+EPAD front year 1. Similar to "Buy in April sell in November" trading strategy, alpha levels are relatively low (0,0066 – 0,0079) which indicates that the "Buy in March, sell in December" strategy can only generate modest excess return. SYS front year 2 and SYS+EPAD front year 2 do not show statistically significant alphas.

Table 11. CAPM regression parameters – Buy in March, Sell in December.

	α_i	β_i^*	R^2	P-value (α_i)	P-value (β_i^*)
SYS Front Year 1	0,00790*	0,36276**	0,02239	0,0906	0,0175
SYS Front Year 2	- 0,0001	0,58606***	0,13558	0,9785	0,0000
SYS+EPAD Front Year 1	0,00665*	0,51672***	0,08002	0,0961	0,0000
SYS+EPAD Front Year 2	0,00093	0,57042***	0,15039	0,0762	0,0000

*denotes 10% significance level, ** 5% significance level, and *** 1% significance level

Third hypothesis of this thesis is that trading time seasonality of SYS+EPAD futures will generate more positive alpha than SYS futures. Based on the results, we can confirm this hypothesis for front tear 1 futures in the "Buy in April, sell in November" strategy. In regard to “Buy in March, Sell in December” strategy, this hypothesis is rejected as SYS front year 1 has marginally beaten SYS+EPAD front year 1.

6 Conclusions

The European energy markets have undergone a significant transformation in recent years. Transformation is primarily driven by increased renewable energy production. For example, wind power capacity in Finland increased from 2268 MW in 2021 up to 6715 MW by the end of 2023 according to the statistics by Fingrid (2024). Secondly, the interruption of pipeline gas imports from Russia to Europe in 2022 caused an energy crisis which led to unpresented price levels in both electricity spot and futures markets. Prices have since returned to more normal levels, but price fluctuations have clearly become a permanent market feature. To counterbalance the high price spikes, negative spot prices have become increasingly common. For example, Finland recorded a total of 467 negative hourly prices in 2023 which means that roughly 5% of spot prices in that year were negative (Yle, 2024).

In the Nordics, electricity market model consists of two main markets: the spot market and futures market. These two markets are closely connected as the spot market is the underlying market for electricity futures. In the spot market, electricity is being traded for the next day, while the futures market deals with upcoming periods such as months, quarters, and years ahead from the present moment. The prices of futures products reflect the markets expectations of the average spot price for that specific time period. There are two types of futures products. System products that cover the entire Nord Pool market area, while EPAD products are always area specific. By combining system and EPAD product, a market participant may create a synthetic futures product that reflects the market’s price expectation for that specific price area. In this case SYS and EPAD volumes need to be the exact same for it to be a synthetic future.

Price seasonality refers to price movements that are cyclical around a certain time period. Regarding electricity markets, seasonality is naturally reflected in the future’s prices as the demand for electricity in the Nordics is cyclical. Futures prices for winter periods are typically higher as demand increases during wintertime as more electricity is needed for heating purposes. Correspondingly, summertime futures prices are typically lower when there is less demand in the Nordics. The seasonality caused by cyclical demand is seen in the future's curve of electricity, which reflects the market's expectations of upcoming prices. However, this is not the only type of seasonality that can be observed in the future's prices. The backward curve $t \rightarrow F(t, T)$ of electricity futures can also display seasonality that is not explained by the underlying spot price or time to maturity. This type of seasonality is called time seasonality by Størdal et al. (2023) and Ewald et al. (2022). Time seasonality is identified through pricing kernel $\frac{d\mathbb{Q}}{d\mathbb{P}}$ in which $d\mathbb{Q}$ denotes the risk-neutral pricing measure and $d\mathbb{P}$ denotes the physical measure. As the pricing kernel depends on t and T, it can cause seasonality in both future and backward curves. The pricing kernel is set by the marginal utility of market participants, meaning that factors such as risk preferences and other human behavioral factors determine the equilibrium of the pricing kernel. For example, Spodniak & Collan (2015) argue that electricity buyers are more risk-averse in Nord Pool price areas that are dependent on imported electricity. And on the supply side, hydro producers can store water in reservoirs and optimize their production and therefore it doesn't make sense to fully hedge their production according to research by Botterud et al. (2009).

This thesis examines the time seasonality of four different types of electricity futures products. These products are SYS front year 1, SYS+EPAD front year 1, SYS front year 2, and SYS+EPAD front year 2. The examination covers the period from beginning of 2018 to end of 2023, and the products under examination are annual products. The methodology of this thesis is similar to Størdal et al. (2023) as they studied the seasonality of electricity futures not only in the Nordics, but also in the German electricity market. Størdal et al. (2023) did not include EPAD products in their research which makes this thesis differ from their study. In markets other than electricity, Etwald et al. (2022) have studied time seasonality of crude oil and natural gas futures. Similarly to Størdal et al. (2023), Etwald et al. (2022) have found that trading time seasonality can generate statistically significant alphas for both commodities. Etwald et al. (2022) speculate that sentiment factors such as hedging pressure of sellers or buyers might be causing the existence of time seasonality, but more detailed analysis is left for further research.

In this thesis, hypotheses are tested first by nonparametric tests, and then these findings are applied into the capital asset pricing model. Nonparametric tests show that trading months in autumn (August-September) and just before end of the year (November-December) are stochastically dominating trading months early in the year (February – April). As expected in hypothesis one, more time seasonality is found in synthetic SYS+EPAD futures compared to SYS futures. In the Dunns' test, a higher absolute z-value indicates greater difference between the selected groups. Z-values are consistently higher for SYS+EPAD futures in comparison to SYS futures. This holds true for both front year 1 and 2 futures. The second hypothesis is that time seasonality is more pronounced in front year 1 futures compared to front year 2 futures. The basis for this hypothesis is that fundamental price drivers in the Nordic electricity market will have a bigger impact on futures that are closer to the beginning of delivery period. Based on the results, this hypothesis can be accepted for SYS+EPAD futures, but for SYS futures alone, this hypothesis is rejected.

Based on the findings of statistical tests, two trading strategies are formed and tested to determine if they can generate excess return in comparison with the market index. In this thesis, Nasdaq's OMX Nordic Energy Net Index is selected to represent the market portfolio. Trading strategies are "Buy in April, sell in November" and "Buy in March, sell in December". Results show that both strategies have generated some statistically significant and positive alpha for SYS and SYS+EPAD front year 1 futures. However, the alpha levels are generally low or moderate. For "Buy in April, sell in November" hypothesis 3 is accepted as SYS+EPAD front year 1 has generated more positive alpha compared to SYS front year 1. However, for "Buy in March, sell in December" this hypothesis is rejected as SYS+EPAD front year 1 has performed worse than SYS front year 1. For front year 2 futures, the results are mostly statistically insignificant, and therefore neither strategy can be recommended for practical application.

The findings of this thesis can be practically applied in the hedging of electricity consumption or alternatively production. For example, large electricity consumers such as industrial companies in Finland should carry out their hedging decisions for the following year well in advance in the early months of the year and avoid making hedges during the autumn or at the very end of the year. This also applies to households that are looking for e.g. 12 or 24 month fixed-price contracts as they should look to tender suppliers in the springtime. For industrial companies that might make hedges 1-3 years ahead, it would also be beneficial to hedge with front year 2 futures in the early months of the year, although the seasonal differences are less pronounced in this case. Respectively, electricity producers should avoid hedging early months of the year and instead focus their hedging efforts in the autumn and towards the end of the year.

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