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# IMPACTS OF THE EUROPEAN EMISSION TRADE SYSTEM ON FINNISH WHOLESALE ELECTRICITY PRICES

Juha Honkatukia
Ville Mälkönen
Adriaan Perrels

Valtion taloudellinen tutkimuskeskus
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Valtion taloudellinen tutkimuskeskus

Government Institute for Economic Research

Arkadiankatu 7, 00100 Helsinki, Finland

Email: etunimi.sukunimi@vatt.fi

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**Tiivistelmä:** Tässä tutkimuksessa tarkastellaan EU:n päästökaupan aiheuttama lisäkustannuksen siirtymistä sähkötukkumarkkinoiden hintaan Suomessa. Tutkimuksessa luodaan katsaus Suomen sähkömarkkinoiden viimeaikaiseen kehitykseen ja esitellään näkökulmia siitä, miten eräät sähkön hinnanmuodosta kuvaavat talousteoreettiset mallit selittävät markkinoiden toimintaa ja hinnanmuodostusta markkinoilla. Tutkimuksen empiirisessä osuudessa arvioidaan ekonometrisesti päästöoikeuden hinnan välittymistä sähkön hintaan. Estimointitulosten mukaan 75–95 prosenttia päästöoikeuden hinnasta siirtyy sähkön hintaan. Tuloksien mukaan myös kapasiteetin käyttöasteella ja sähkön kysynnällä on vaikutusta sähkön hintaan. Tulosten perusteella ei ole mahdollista tehdä päätelmiä markkinoiden kilpailullisuudesta, mutta empiirisen tutkimuksen tulosten ja teoreettisten epätäydellistä kilpailua kuvaavien mallien välillä on havaittavissa yhteneviä piirteitä. Tämä on mahdollisesti merkki epätäydellisyyksistä sähkömarkkinoilla, mikä voi osaltaan vahvistaa päästökaupan hintavaikutuksia.

**Asiasanat: sähkömarkkinat, päästökauppa, markkinarakenne**

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**Abstract:** This study deals with the matter to what extent the costs of the EU Emission Trade System (EU ETS) end up in the electricity prices. The study encompasses both a theoretical and an empirical review of electricity price formation. It includes an econometric analysis of electricity price formation and the impact of EU ETS on power prices. On the basis of the econometric analysis is concluded that cost compensation due to EU ETS is indeed occurring. On average, about 75% to 95% of a price change in EU ETS is passed on to the Finnish NordPool spot price. The analysis also shows that the degree of utilisation of generation capacity (and hence the network loads) have an effect on electricity prices. This hints at possible market imperfections and can aggravate the price effects of EU ETS.

**Key words: electricity markets, emission trading, competitiveness**

# Summary

This report reviews the effects of the European Union Emission Trading Scheme (EU ETS) on electricity prices in Finland. The report gives an overview of the theory of electricity price formation and proceeds to empirically assess the developments in the first 16 months of emissions trading. The goals of the study are twofold. First, the theoretical review aims at explaining the pricing mechanisms that may be relevant at the Nordic electricity markets in different market situations. Second, the empirical part of the report deals with econometric estimations of the extent to which EU ETS allowance prices affect the wholesale electricity prices in Finland.

The estimation results indicate that compensation of the cost effects of EU ETS is indeed occurring even though with variations, mainly depending on the levels of power demand. On average, about 75% to 95% of the price changes in EU ETS are passed on to the Finnish NordPool spot price. It should be noted that usually the electricity sold via the spot market is based for less than 50% on fossil fuels (peat included).

The fact that capacity utilisation appears to affect the sensitivity of wholesale electricity prices for input cost may be an indication of market power. Yet, the current study was not designed to assess market power in depth. Consequently, no definite conclusions can be made on this point. The theoretical explanations clarify how market power can be established and be used to increase prices above a competitive equilibrium level. It should be realised that in practice price levels above marginal cost might emerge in perfectly competitive markets due to high demand combined with insufficient capacity.

Senior advisor Pekka Tervo from the Ministry of Trade and Industry has supervised the study. The authors would like to thank him and the other members of the steering group for their valuable comments and also gratefully acknowledge the assistance of Tarja Tuovinen in data collection and estimation.

# Contents

# 1. Introduction

This report studies the effects of the European Union Emission Trading Scheme (EU ETS) on wholesale electricity prices in Finland. The report gives an overview of the theory of electricity price formation and proceeds to empirically assess the experience from the first sixteen months of emission allowance trading. The goals of the study are twofold. First, the theoretical review aims at explaining the pricing mechanisms that may be relevant at the Nordic electricity markets in different market situations. Second, the empirical part of the report aims at forming a picture of the pass-through of allowance prices to electricity prices.

The report starts with an overview of recent developments in the Nordic wholesale electricity market (the NordPool area) in terms of prices and quantities in chapter 2. Chapter 3 reviews theoretical models of electricity pricing and shows how the pass-through of ETS prices to electricity prices may depend on many factors, starting with fuel prices and proceeding to capacity utilisation and other factors affecting the system load. In chapter 4, the price formation of wholesale electricity in the NordPool area is assessed in relation to its short run and long run driving forces. More in particular the development of daily and hourly system prices in the Finnish market area of NordPool is tested regarding their correlation with various capacity scarcity indicators (utilization rates), input cost indicators such as the prices of coal, natural gas, and EU ETS emission allowances, as well as demand shaping indicators (temperature, working day or not, etc.).

Chapter 5 sums up the conclusions from the theoretical and empirical exercises.

# 2. The Nordic electricity market

## 2.1 Production of electricity in the Nordic markets

Production and retail sales of electricity are competitive sectors in Finland and the other Nordic countries. So, from an overall perspective prices should one way or the other reflect cost. There are many ways in which this can be realised. Crucial in this respect is that price formation on the Nordic wholesale electricity market is supposed to be subject to free competition. Because electricity is to be produced at the moment it is needed, a merit order of production units emanates from the market function, in such a way that the lower merit order units are so called marginal units, producing only in periods when there is sufficient demand to justify their operation. As a consequence in any given period the cost of the marginal unit determines the electricity spot price (figure 2.1).

As also happens in the actual power market figure 2.1 illustrates that part of the time, e.g. during nights and during the summer vacation period, the wholesale electricity price (where the MC curve intersects with the demand curve) is below the total cost per kWh.

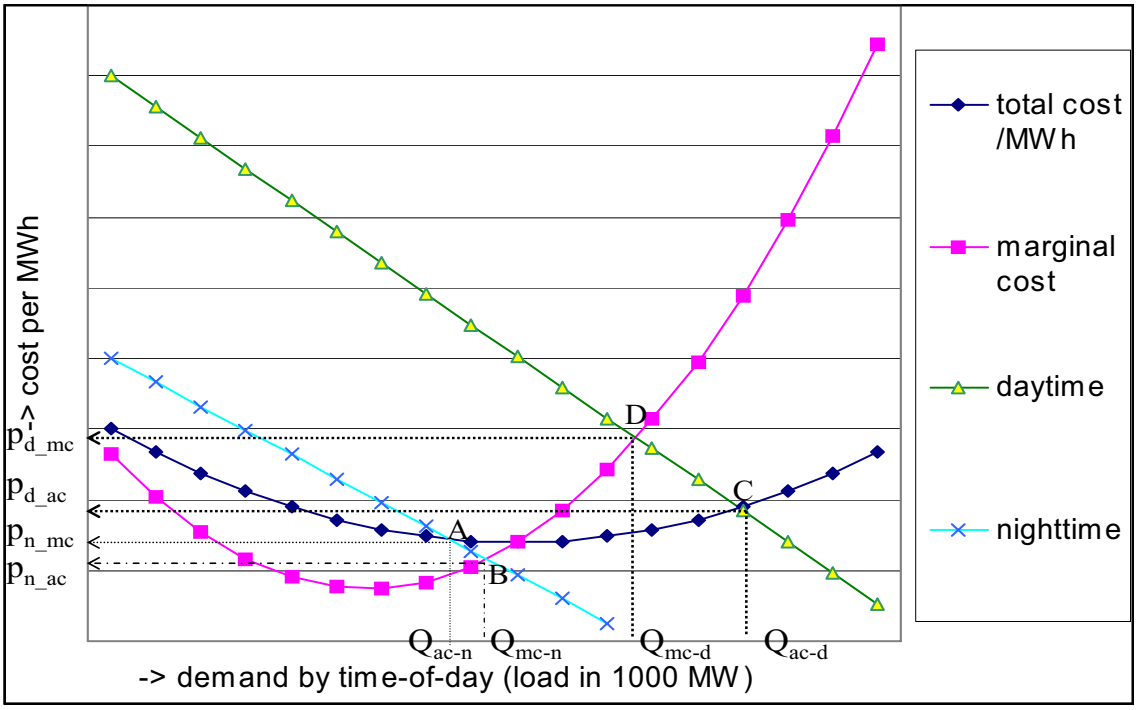


*Figure 2.1. Price formation in the electricity market during lower and higher demand periods respectively*

The merit order is such that hydro power, nuclear power, and industrial and district heat CHP[1] capacity are almost constantly in use, even though hydro and district heat CHP are not always used at full capacity (for different reasons). Condensing power (in Finland only coal fired) is only used during times with high(er) demand. The use of hydro power is very flexible and is therefore also used to accommodate quick changes in the level of electricity consumption. Gas fired combined cycle is also a quite flexible power source, but with much higher cost per kWh than hydro power. The use of combined cycle for CHP-DH system will lower the flexibility, but also result in lower cost per kWh. Coal power is to some extent flexible, in the sense that the capacity utilisation of a running coal power station can be varied within certain lower and upper limits. Yet, the starting time of a coal power station is appreciably longer than a gas fired unit (like days versus hours). Combined heat and power stations are following the heat demand and are therefore not flexible with respect to power demand variations. Nuclear power is constantly operated at (near) full capacity.

Next to purchasing electricity generated in Finland buyers can import electricity, either from Russia or from other producers in the NordPool area. Russia is outside the NordPool area, and the supply contracts have a more pre-fixed longer term character. Over the connection with Russia electricity is only imported, never exported. The imported electricity from other producers in the NordPool area (mostly hydro power based) has to be supplied via the links between Finland and Sweden. These connections are used in both directions. There are also days or even periods with predominantly export flows to Sweden rather than import. The imported electricity from other producers in the NordPool area is purchased under the same market conditions as the wholesale market within Finland. However, if the demand for electricity from the rest of NordPool is larger than the transmission capacity, congestion arises, and consequently wholesale spot prices in Finland can rise above those in other NordPool areas. The implication is that the price of import electricity (from the NordPool area) can vary substantially. The import price is affected by the overall demand levels (at the same time) in the NordPool area as well as by the degree of filling of the reservoirs, especially those in Norway.

The costs of electricity generation (per kWh) vary over the types of generation. Capital costs are in particular high for hydro and nuclear. High utilisation rates and long lifetimes reduce these costs (per kWh) however. For hydro the cost of input fuel are absent, whereas they are low for nuclear capacity. Fuel costs are significant for fossil and bio-fuel capacity, although the latter can be cheap in some industrial settings. The introduction of the European emission trade system (EU ETS) has added to the cost of fossil fuel use.

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[1]. CHP = combined heat and power, meaning that both the heat and the electricity are used. CHP capacity for district heat (CHP-DH) is usually off-line in the summer period.

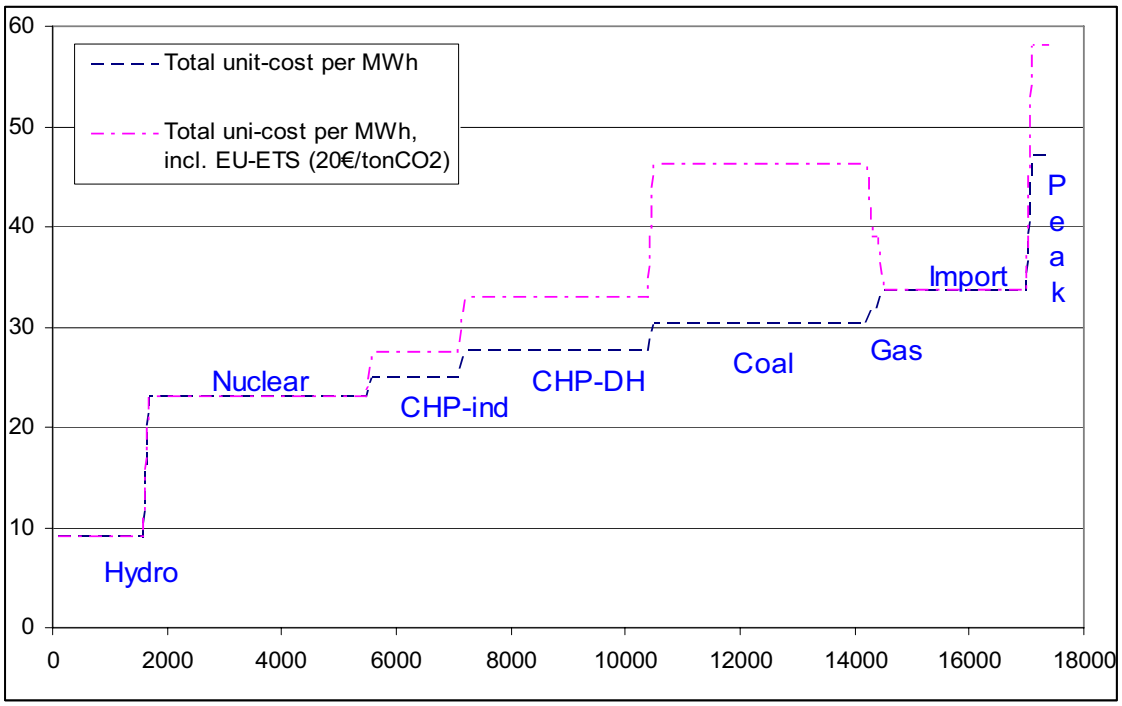


*Figure 2.2a. Illustration of approximate total unit-cost per MWh of various types of capacity in Finland in a dry year while applying low return on investment targets, and the cost addition due to EU-ETS by type of generation*

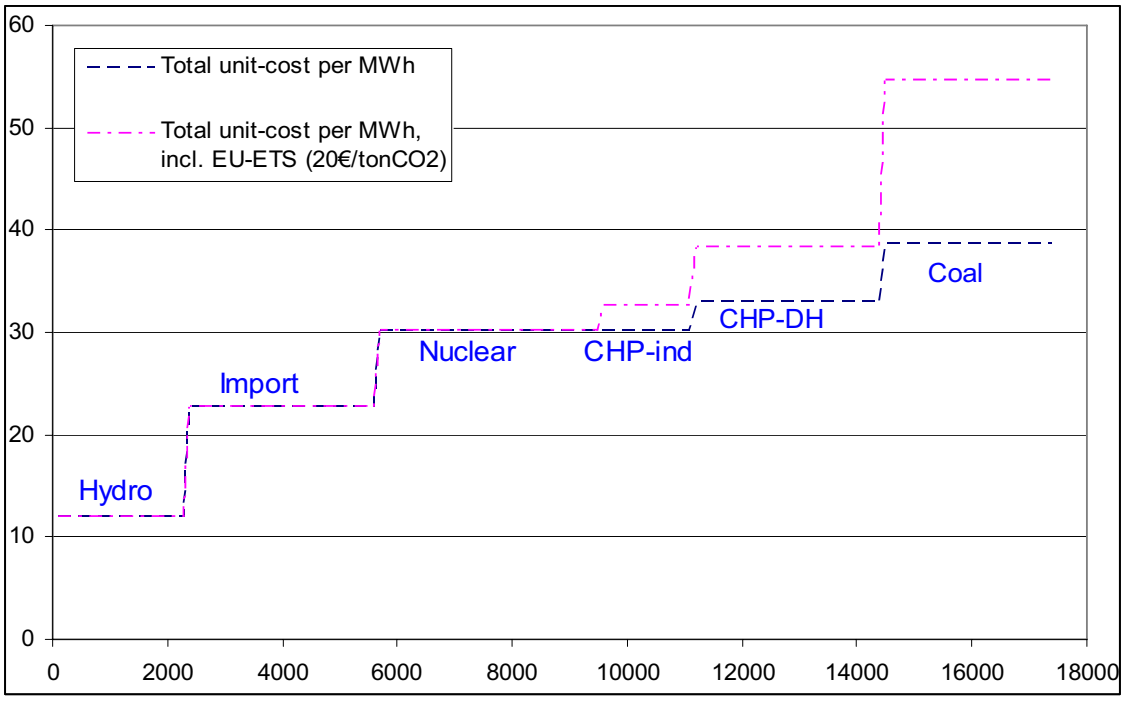


*Figure 2.2b. Illustration of approximate total unit-cost per MWh of various types of capacity in Finland in a wet year while applying high return on investment targets, and the cost addition due to EU-ETS by type of generation*

Source: updated from Perrels and Kemppi (2003)

Figures 2.2a and 2.2b illustrate the *approximate* cost per MWh of Finnish capacity for situations with strained hydro reserves ('dry year') in combination with a low with return on investment target (figure 2.2a) and with abundant hydro reserves ('wet years') in combination with a high return on investment target (figure 2.2b). The figures should be understood as illustrative approximations[2] of total cost per MWh (so *not* marginal cost per MWh). Actual figures can vary for many reasons (see also footnote 2).

For both cost curves is also demonstrated how the total unit-cost rise if the cost of a ton $CO_2$ (at a price of 20 € per ton) is attributed to the produced megawatt-hours from the $CO_2$ emitting capacity in accordance with the carbon intensity of the fuels used and the conversion efficiency. Industrial CHP has on average a higher share of renewables in its fuel mix than CHP in district heat systems and consequently the mark-up due to emission allowance cost is lower. In figure 2.2a the assumed average import price is rather low. In fact at least for a part of the year (which is supposedly dry) import prices of power from elsewhere within NordPool can be expected to be appreciably higher and consequently a part of the year coal (and gas) will be competitive compared to import power notwithstanding the extra cost due to EU ETS..

Table 2.1 provides an overview of the installed generation capacity in Finland and the other NordPool countries. Also the transmission capacity between NordPool countries and with non-NordPool countries is shown as of 31 December 2004. Since then no significant changes have occurred.

It should be realised that not all capacity as listed in table 2.1 can be fully accounted for. Wind power capacity is seldom simultaneously in full use. District heat related capacity is steered by the demand for its heat output and is usually switched off in summer months. In case of low reservoir filling rates there will be reluctance to use of a lot hydro capacity, because the option value of the water in the reservoir is much higher in such circumstances. Some of the non-CHP fossil fuel capacity was mothballed in the past, implying low actual availability of such capacity. Next to the technology specific availability features there are maintenance cycles for all types of capacity as well as disturbances, also in the transmission links. The observed monthly utilisation rates of various types of power capacity during the year 2004 are shown in figure 2.3.

[2]. The unit-cost figures are based on total cost and typical annual production time per unit type for new units, while using an ROI of 5% and 10% respectively. Due to variations in accounting practices, input costs, and utilisation rates actual unit costs can vary significantly.

*Table 2.1. Installed production capacity by generation type and cross-border transmission capacity in the NordPool area (in MW) as of 31-12-2004*

| ***generation type*** | **Finland** | **Denmark** | **Sweden** | **Norway** | **Nordpool** |
|---|---|---|---|---|---|
| Nuclear | 2 671 | 0 | 15 274 | 0 | 17 945 |
| CHP-DH (fossil and peat) | 6 627 | 8 237 | 3 863 | 8 | 18 735 |
| CHP-industry (fossil and peat) | 996 | 381 | 317 | 49 | 1 743 |
| Other fossil (non-CHP) | 800 | 270 | 1 623 | 64 | 2 757 |
| Waste | 131 | 271 | 153 | 27 | 582 |
| Biofuel (CHP) | 2 198 | 418 | 1 545 | 96 | 4 257 |
| Hydro | 2 986 | 11 | 16 137 | 27 925 | 47 059 |
| Wind | 79 | 3 122 | 442 | 158 | 3 801 |
| **Total installed** | **16 488** | **12 710** | **39 354** | **28 327** | **96 879** |
| Simultaneously available maximum capacity * | 13600 | 7870 | 27700 | 22800 | 71970 |
| *Import capacity* | to Finland | to Denmark | to Sweden | to Norway | to non-Nordpool |
| from Finland | - | - | 1800 | 100 | 0 |
| from Denmark | - | - | 2400 | 1000 | 1900 |
| from Sweden | 2 200 | 2 100 | - | 3300 | 1200 |
| from Norway | 100 | 1 000 | 3600 | - | 50 |
| from non-Nordpool | 1 500 | 1500 | 1200 | 50 | - |

CHP: Combined heat and power; DH: District heat; Bio-fuels are predominantly used in CHP units. Peat is to varying extents also co-fired in bio-fuel using installations.

*) For Sweden it includes 600 MW peak reserve and frequency controlled reserve. For Finland it excludes 1080 MW peak reserve and frequency controlled reserve. Furthermore in Finland 435 MW installed capacity (other fossil) was mothballed at that time.

Source: Nordel and Statistics Finland

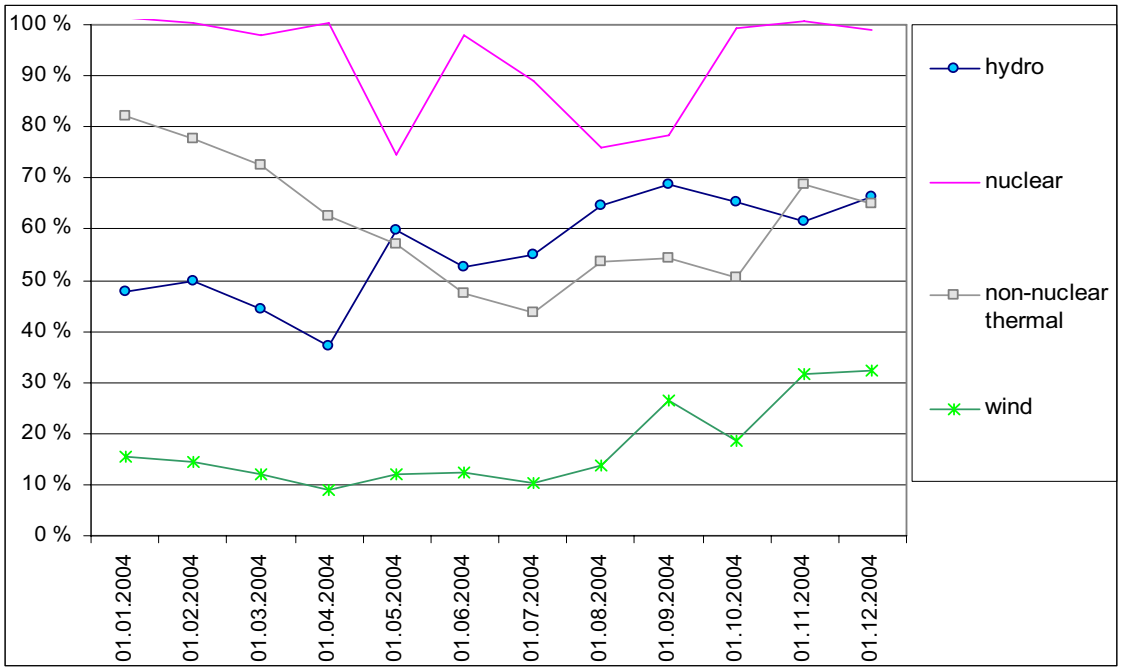


*Figure 2.3. Utilisation rates by month of various types of capacity in the Finnish system in 2004* (source: Nordel)

Consumption and production show daily, weekly and annual cycles (figure 2.4). In addition weather conditions can elevate or diminish average consumption levels. The impact of the strike in the paper industry in 2005 is clearly reflected in the development of consumption and production in that year. In this respect it is also worth noting that the resumption of the electricity consumption (after the strike) to normal levels for the time of the year, is only partly matched by a similar increase in domestic production, instead electricity imports rise remarkably. This increased reliance on imports – especially from the NordPool area – continues well into the year 2006, even though at gradually decreasing levels. Also bearing in mind the modest trade volumes in EU ETS in its initial stages, it seems that more serious realignments in capacity allocation in response to EU ETS occurred in July 2005.

From the presented supply and demand information presented here in figures 2.3 to 2.4 can be inferred that demand developments can be predicted to some extent, but a large number of daily and hourly 'disturbances' necessitate a constant accommodation to actual demand levels. It should be realised that retail prices (and hence all final demand outside heavy industry) only respond in a filtered way and with delay to the wholesale price developments.

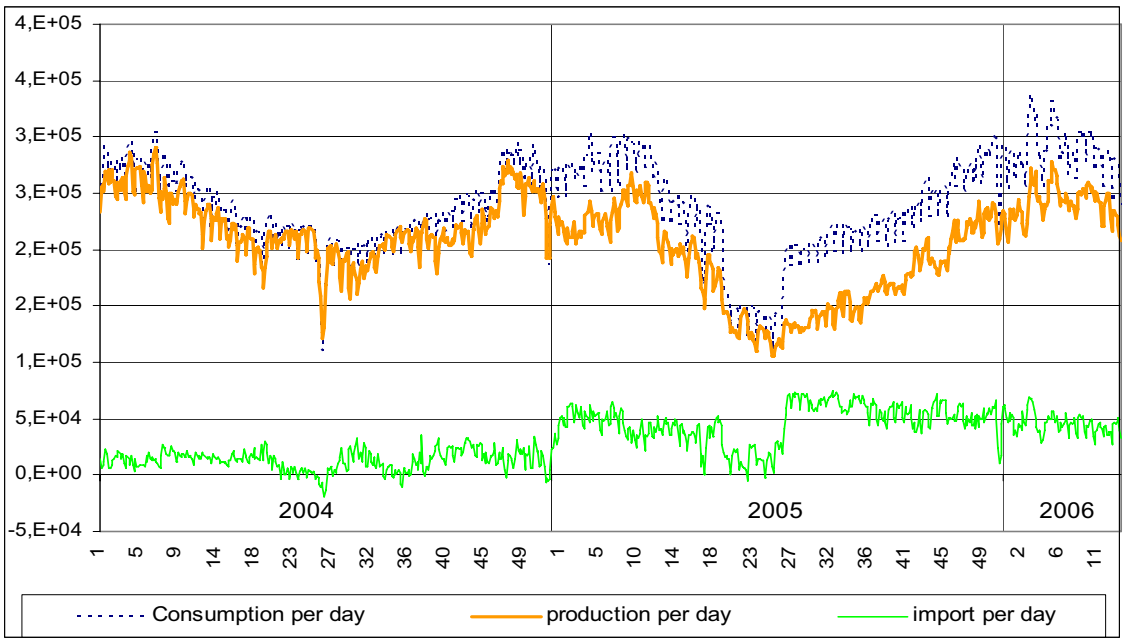


*Figure 2.4. Daily consumption and production of electricity in Finland and daily net import to Finland in MWh (x 100.000) (numbers along the x-axis denote sequence numbers of weeks; source: NordPool)*

## 2.2 Developments of key factors in the recent past

The wholesale electricity price in the NordPool area and in the Finnish sub-area went through several very high price periods in 2002 and the beginning of 2003.

Since then up to the beginning of 2005 price variations have been more moderate. Figure 2.5 shows the daily weighted average spot prices for Finland and the entire NordPool area ('system price') respectively for the period 1-1-2004 to 7-5-2006. The reason for the earlier high prices (in 2002/2003) was the simultaneous occurrence of very cold winter weather and below average reservoir fillings. During the year 2004 and even more so during 2005 the hydro reservoir filling came back to long term average levels. This return to more or less normal filling levels alleviated the tensions regarding possible price rises.

During the year 2004 coal prices are initially rising more than natural gas prices, but from November 2004 onwards the coal prices level off, whereas natural gas prices continue to rise for the rest of the observation period. The prices shown refer to the monthly average import prices of coal and natural gas for Finland. It should be stressed that the prices for internationally traded natural gas in Western Europe hovered at higher levels and showed more volatility. From the point of view of unit-cost of electricity production in Finland the fuel prices shown in figure 2.5 are the relevant ones.

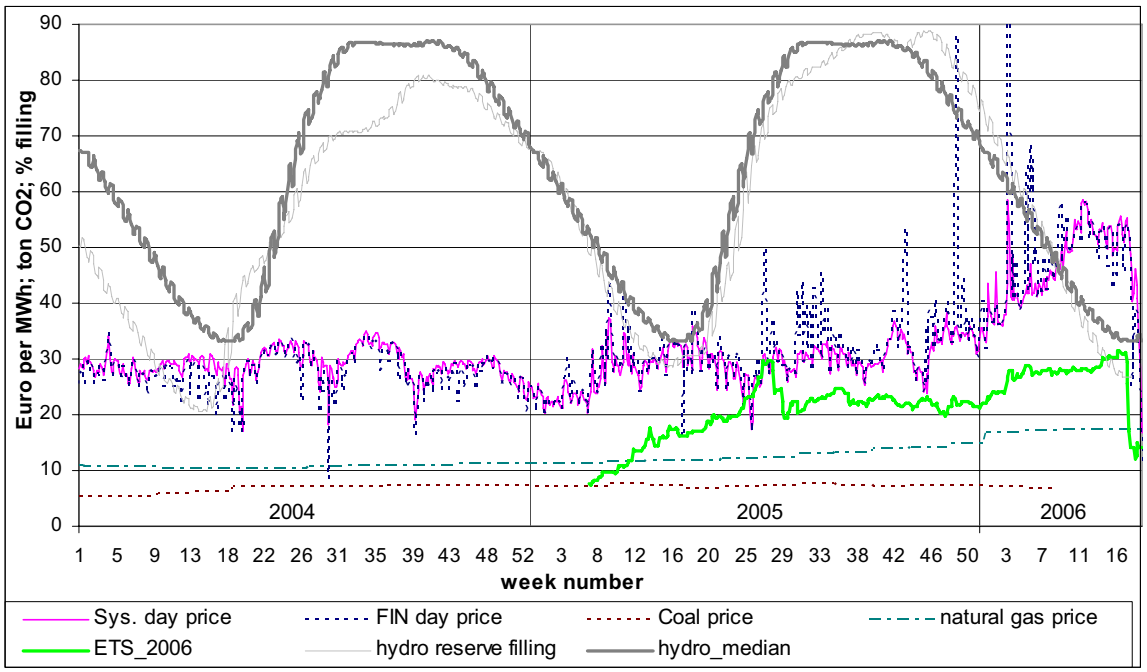


*Figure 2.5. Development of key factors in the Finnish wholesale electricity market*[3]

The price notation of EU ETS tradable allowances started in February 2005. There is a notation for each year in the first commitment period 2005-2007, as well as for allowances for the years 2008–2012. Even though the levels are not

[3]. Prices for electricity and EU ETS, as well as the hydro reservoir filling rate are from NordPool; monthly average prices for natural gas and coal are from Statistics Finland.

exactly the same the price movements are highly similar. For this reason the analysis has been focusing on the allowances for 2006, which has the advantage of having price notations continuing in 2006 while also having the largest turnover in the allowance market during the time span analysed. In the EU ETS market trade volumes were initially small. Trade volumes reached more mature levels in august 2005 and continued to expand since then.

## 2.3 Emission trading and electricity prices

The price developments of EU ETS allowances and wholesale electricity as shown in figure 2.5 would make any observer inclined to be believe these price developments are correlated. It is indeed easy to explain why electricity wholesale prices will rise to a certain extent as a consequence of the introduction of a $CO_2$ allowances cap-and-trade system. Regardless of the method of issuing of the allowances at the beginning of the trade system, i.e. 'grandfathering' or auctioning, the opportunity cost (=price) of an allowance at a certain moment is the same in both variants of the system. In turn the opportunity cost, i.e. the allowance price, will be accounted for in the costing of the electricity generation. The cost of the $CO_2$ will exert pressure on generators to increase prices at the margin. Indeed that means that also electricity from carbon free units, that have usually lower unit cost, can be sold against the same augmented price.

But while the basic effect of emission trading on unit costs is clear enough, it is difficult to assess with a reasonably degree of precision *by what amount* the electricity wholesale price has risen during a certain time span as a result of price rises in EU ETS. There are several reasons for this. Firstly, wholesale electricity prices vary for a host of reasons other than EU ETS. Secondly, there are several types of wholesale markets (figure 2.6), whose price formation is interlinked, but not identical. In this case especially the links between spot market and forward/bilateral markets is important, as is possibly their share in overall electricity trade. For example, distributors can decide to buy more via longer term forward contracts in order to shed risks of EU ETS induced price peaks. In response generators may decide to be more cautious in charging very high spot prices.

A third complicating factor is that the price development of $CO_2$ allowances in EU ETS is influenced by the degree of (expected) target accomplishment in the power sector. Finally, the prices of fossil fuels may interact with the EU ETS prices. A higher EU ETS price has larger cost implications for coal users than for natural gas users, and consequently users that have a choice may be willing to pay a premium for getting gas. If fossil fuels are getting more expensive, it is likely that prices of EU ETS may decrease or – depending on other factors – rise less than otherwise would be the case. There may also be regional variations. In the Finnish case, natural gas prices are based on a bilateral market with Russia. In the Central European markets, however, gas is widely regarded as the alterna-

tive for curbing emissions from coal-fired plants, and, consequently, there is a link between the (daily) EU ETS prices and the natural gas prices on main European markets.

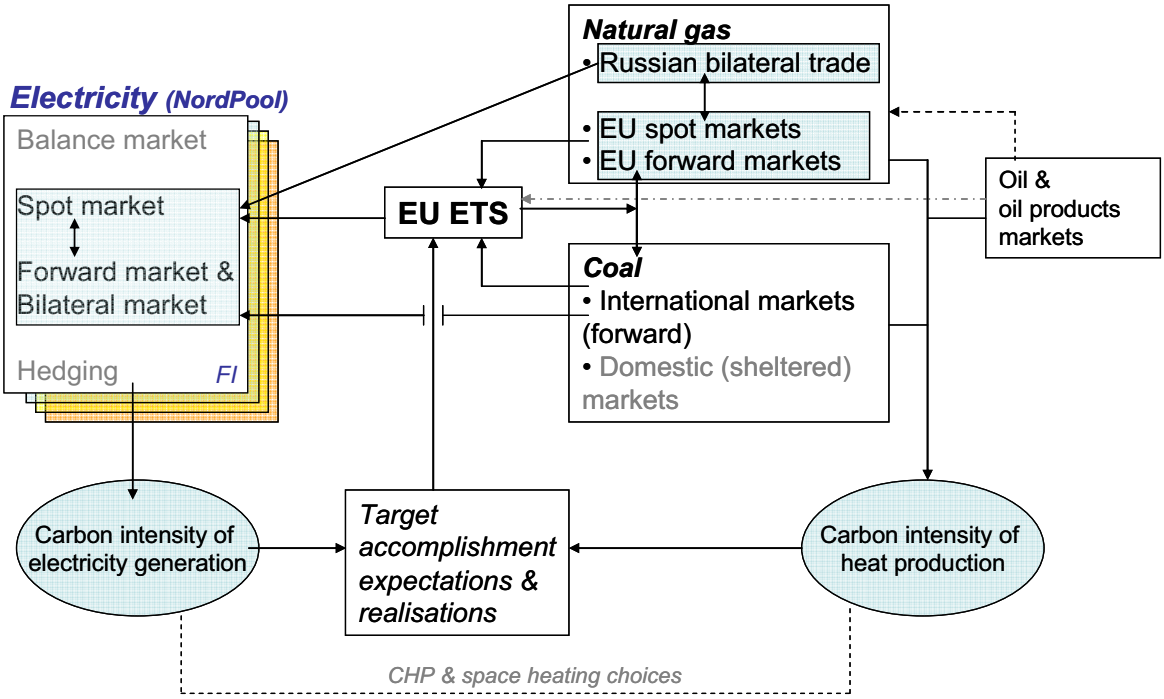


*Figure 2.6. Direct and indirect linkages between fossil fuel markets, EU ETS, and electricity markets*

There are still other background factors such as the degree to which the electricity and heat markets are linked in the various EU member states, and in this case more specifically the countries participating in NordPool.

Last but not least it should be realised that the influence of natural gas is important, because for the time being fuel switching, notably from coal to gas, is the prevalent strategy for power companies across the whole EU (even though relatively less so in the Nordic power market). If energy saving as well as switching to renewable energy carriers and nuclear would become much more important strategies, the relations between electricity prices, EU ETS and fossil fuel markets could change significantly.

# 3. Electricity pricing in theory

The previous section presented anecdotal evidence and some descriptive statistics of the Nordic electricity market. This section provides an illustration on the market mechanisms that might be driving prices in the electricity markets. In particular, we will describe a common outcomes derived in some models of imperfect competition considered plausible in modelling electricity markets. These theoretical ideas are then used to explain the anecdotal evidence. The reader should, however, note that these results are *very preliminary* as they lack formal game-theoretical foundations of the analyses cited below.

The analysis proceeds in three steps. First, we define the concept of the use of market power and show that excessive profits may not necessarily imply imperfect competition. Second, we illustrate some stylized models, which capture the basic properties of capacity constrained markets under perfect and imperfect competition. We use the ideas put forward in these models to analyze the impacts of ETS on electricity prices. Finally, we show which model best resembles the anecdotal evidence observed in the Nordic markets and discuss the policy implications.

## 3.1 Perfectly and imperfectly competitive equilibria

As a general rule, competition is imperfect when a producer can affect the market price through its output decisions. This means that a producer is not a price taker, and might have an incentive to decrease its output so as to increase the market price above the marginal cost of production. In what follows, we will first describe the structure of Nordic electricity markets in a simplified manner. Second, we will illustrate the properties of competitive outcomes in such markets. Finally, we illustrate how generators with market power can use capacity with-holding to affect the market prices.

The Nordic electricity markets operate via NordPool which is the spot market for retail electricity. In Norpool the generators first announce (bid) their supply function to an auctioneer (NordPool). The supply functions are pairs of prices and quantities to which the generators are committed.[4] The supply function corresponds with the marginal cost of production of the generators. Given the generators' bids and the demand, the auctioneer then selects a market clearing price which satisfies the demand and the announced supply functions. The resulting equilibrium price for retail electricity on the basis of which the consumer prices are set by the distribution companies. The structure of the spot market thus resembles closely the model of competition in supply functions derived in Klemperer and Meyer (1989) and Vives (1985).

[4]. In other words, the supply function determines the minimum prices for which a generator is willing to produce a specified quantity for the market.

Consider then a perfectly competitive electricity market where the generators, for simplicity, have two generation technologies: hydro power and fossil fuel power. We further presume that the marginal cost of production is lower for hydro power and increases discontinuously when the generator switches to fossil fuel power (See Figure 2.2). This means that a supply function of a generator is given by

$$MC = C_h \quad for \quad Q \le \bar{Q}$$
$$MC = C_c \quad for \quad Q > \bar{Q}$$

where $MC$ denotes the marginal cost of the *last unit produced* and $C_c > C_h$ reflects the property that the unit cost of producing hydro power is lower than that of fossil fuel power. There is a capacity constraint for hydro power, $\bar{Q}$, implying that increasing production in excess of $\bar{Q}$ shifts the lowest price for which the generator is willing to produce equal to $C_c$. In what follows, we denote the maximum quantity of hydro power the generators can *feasibly announce* in their bids as $\bar{Q}$. The quantity of hydro power *optimal to announce* for the auctioneer by the generators is denoted by $Q^*$. Production of fossil fuel power is denoted by $Q_c$. In what follows, the expression $MC$ will be used to denote the marginal cost of production under the assumption that the market is not regulated by the ETS. In the analysis of market outcomes under ETS, the marginal cost of fossil fuel is denoted by $MC + s$. This is the marginal cost of production with fossil fuel including the cost effect of ETS:

$$MC + s = C_c + s \quad for \quad Q > \bar{Q}$$

Given the above supply function and an arbitrary demand function $P(\mathbf{Q})$, the auctioneer sets the price. If the demand function is common knowledge, a perfectly competitive generator chooses $\bar{Q}$ so as to maximize

$$\pi = P(\mathbf{Q}) * Q - MC * Q$$

where $P(\mathbf{Q})$ is the market clearing price, given the aggregate supply $\mathbf{Q}$. In a perfectly competitive market, the generator cannot influence the output decisions of its rivals. This means that $dP(\mathbf{Q})/dQ = 0$, and thus, the profit maximization condition $d\pi/dQ = 0$ implies that equilibrium price in the market satisfies the property that marginal revenue of production equals the marginal cost, $MR = MC$. In a perfectly competitive market the equilibrium price boils down to the following expression

$$P = MC$$

i.e. the price equals marginal cost. The following figure illustrates this result under different demand levels. Function $P'$ illustrates low demand level, $P''$ illustrates medium demand and $P'''$ stands for peak demand:

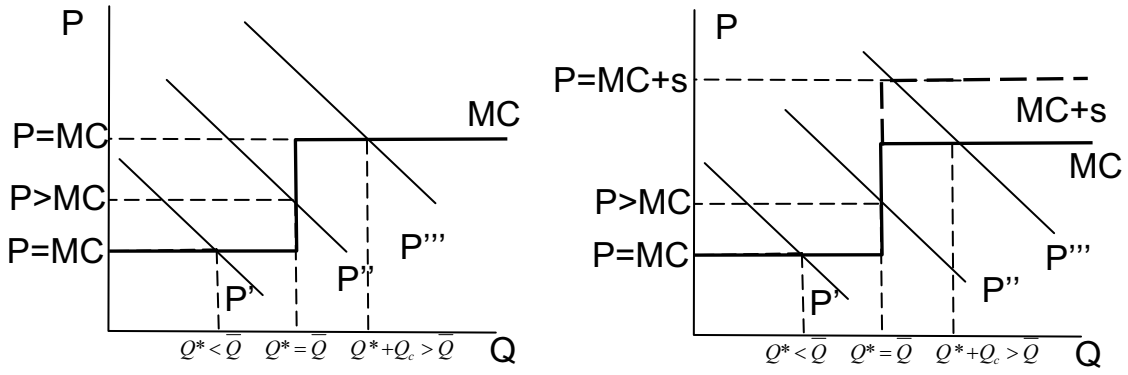


*Figure 3.1. Equilibrium with capacity $Q^*$ under perfect competition*

Figure 3.1 readily illustrates the property that when the generators produce at capacity $Q^* = \bar{Q}$, but the demand for electricity is at a level $P'$, the price exceeds the marginal cost of the last unit produced. It is however important to note that although the generators make positive profit, it does imply that the generators have market power, as they are price takers in the market. In what comes to the decision of the supply function, it is clear that in a competitive market each producer sets $Q^* = \bar{Q}$, insofar as $C_h \leq P(\mathbf{Q})$.

Under perfectly competitive market, the ETS price $s$ passes through to electricity prices in full, if the demand level is high, $P'''$. Under lower levels ($P'$ and $P''$) ETS should not show up in the prices posted on the spot market. This argument is obviously based on a simple analysis which omits important factors in the electricity market, for instance, it does not consider the role of forward trading and other hedging behaviour in the electricity market.

Consider then imperfectly competitive markets where the generator's bid affects the auctioneer's price setting. This can be formalized in the following manner $dP(\mathbf{Q})/dQ < 0$. Intuitively this means that if a generator submits a supply function where the capacity up to which it can produce with lower marginal cost is higher, the auctioneer can feasibly lower the price that clears the market. In all models of imperfect competition, we can derive the following result:

$$P - [dP(\mathbf{Q})/dQ]Q = MC, \tag{3.1}$$

where $P - [dP(\mathbf{Q})/dQ]Q = MR$ and $dP(\mathbf{Q})/dQ < 0$. This expression contains the same elements as the one in the case of perfect competition and an additional

strategic component which illustrates the market power of the producer. That is, the optimal bid for a generator involves lower output than in the case of perfect competition. In equilibrium, we therefore have higher prices and lower aggregate output.

Plausible models of imperfect competition in electricity markets and other capacity constrained markets involve Green and Newberry (1992), Maggi (1996), Klemperer and Meyer (1989), Kreps and Scheinkman (1983) and Vives (1985). These papers, although different in many ways, belong in the same class of oligopoly models where the convexity of cost function serves as a proxy for the intensity of competition. In our simplified example, the cost function is piecewise linear, but globally convex, and the emission trading cost $s$ is a parameter which increases the convexity and therefore mitigates competition. In these models it can be shown that the profit maximizing capacity level for a producer is given by $Q^* = Q < \bar{Q}$ which satisfies (1).[5] This general result is illustrated in Figure 3.2 which describes the imperfect competition equilibrium with demand function $P''$.

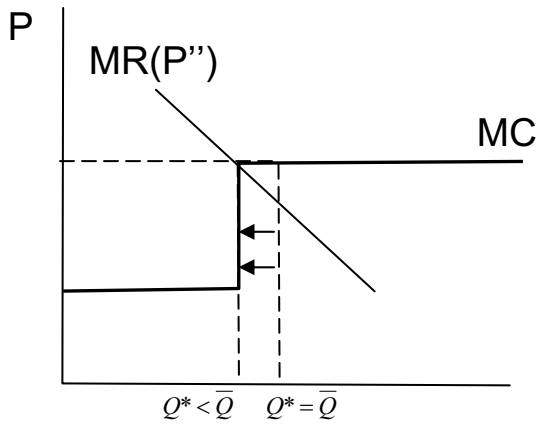


*Figure 3.2. Optimal output $Q^* < \bar{Q}$ with capacity with-holding*

Figure 3.2 illustrates the property that under imperfect competition, the producers are induced to submit supply functions with lower capacity level $Q^* < \bar{Q}$. This outcome can be derived in most models of capacity constrained oligopoly and satisfies the following properties useful in understanding the electricity markets. *First,* the price correlates strongly with the marginal cost of production of the next unit of output. In the present framework, this cost equals the marginal cost of fossil fuel power. This result implies *the second property*: The market clearing price is driven by the marginal cost of fossil fuel power, but the production is mostly hydro power. These results combined imply the *third property*: Changes

[5]. Green and Newberry (1992) and Klemperer and Meyer (1989) do not consider a model where the producer can adjust its capacity levels, but they show that the highest profit levels obtain when the cost function is very convex such that the outcome coincides with the Cournot outcome. Maggi (1996) and Vives (1985) show that if the generators can adjust their capacities, they can indeed implement a Cournot outcome when the vertical segment of the *MC* function is sufficiently high.

in the production cost of fossil fuel power, such as the price of an ETS allowances, will be passed on to the price of hydro power in full.

## 3.2 Anecdotal evidence from Nordic markets and theoretical models of imperfect competition

Having provided a rough illustration of market outcomes in different competitive models of electricity markets, we discuss how the anecdotal evidence available in Nordic markets can be linked to the theoretical models. The market is characterized by the following properties. The first property is that the price of electricity correlates strongly with the cost of fossil fuel energy and therefore with the cost of ETS allowances program. The second property is that most of the consumed energy is produced using non-fossil fuel power, which is not subject to emission trading program. Next we examine the circumstances where these properties show up as an equilibrium phenomenon in different models of competition. To this end, we use the ETS price as a proxy which can be used as a link to the anecdotal evidence and theoretical models.

In Figure 3.1 the equilibrium outcome satisfying the stylized properties of the Nordic markets, requires that at any given time the inverse demand function intersects the marginal cost function at point $(\bar{Q}, C_c + s)$. Any other demand function would either implement an equilibrium with lower prices or higher quantity with a fraction of output produced with fossil fuel power. This, in a dynamic market setting, rather unusual outcome is illustrated in Figure 3.3:

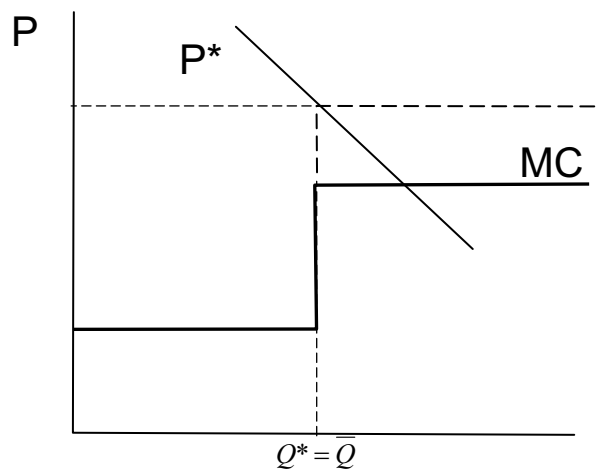


*Figure 3.3. Demand function implementing* $Q^* = \bar{Q}$ & $P = MC + s$.

In figure 3.3 the demand function which satisfies the stylized properties is $P^*$ which traces through point $MC + s$ Under perfect competition, any other demand function either results in price lower than marginal cost $C_c + s$ or higher output than $\bar{Q}$. For any given demand function satisfying $P''(Q) > P(Q)$ a change in $s$

does not affect the price, because the demand function intersects $MC$ function at the vertical segment. This outcome violates the property that the price of electricity correlates with $s$. A demand function with $P''(Q) < P(Q)$ results in equilibrium where $Q > \bar{Q}$, which in turn violates the property that no fossil fuel energy is used in production. On the basis of these equilibrium properties, we can hypothesize that the properties of the Nordic electricity markets are feasible only in *limited circumstances*, if the market is perfectly competitive. That is, the demand function (which is obviously stochastic in the long run) must satisfy very specific properties.

In the case of capacity constrained oligopoly the generators adjust their capacity to satisfy the rule $MR = MC$. This means that the price of output satisfies $P = MC - [dP/dQ^*]Q^*$. That is, the prices are above the marginal and the generators produce exactly at capacity, i.e. $Q = Q^*$. As mentioned above, in models of capacity constrained oligopoly, the equilibrium is such that the capacity is chosen so that $MR = C_c + s$. This is illustrated in figure 3.4

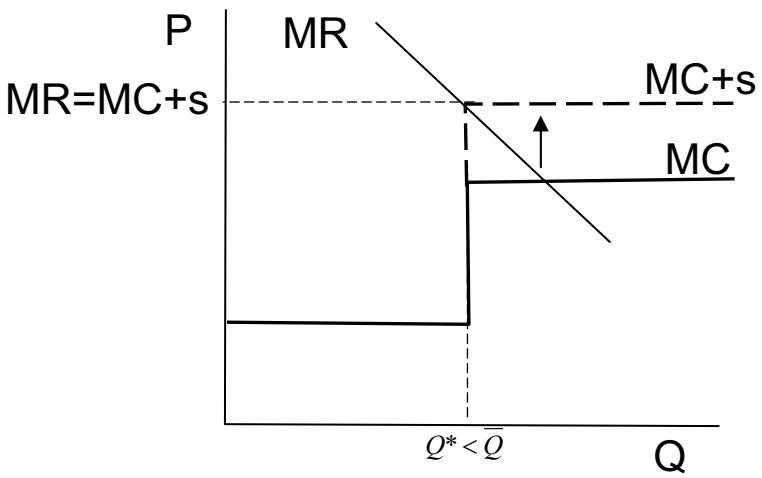


*Figure 3.4.*

Figure 3.4 illustrates that for any given demand level, the capacity constrained oligopoly model satisfies the property that the generators produce using hydro energy and the price of ETS allowances passes on to the electricity prices. As opposed to the results derived under perfect competition, this in line with the anecdotal evidence. That is, the spot-market energy prices correlate strongly with the price of ETS allowances even in times when no fossil fuel power is used in production and the demand levels are relatively low. One interpretation of this linkage between the theoretical models and the evidence is that the generators submit bids with lower capacity levels optimal under perfect competition. Should this be the case it is not implausible to think that the generators are, at least to some extent, employing their market power to impose upward pressure on Nordic electricity prices.

## 3.3 Summary

A non-formal analysis combining the key industrial organization aspects of electricity markets where the generators are subject to capacity constraints points out certain equilibrium properties which resemble the anecdotal evidence and the empirical results on pricing in Nordic electricity markets. Under perfectly competitive markets, the spot market prices are higher than the marginal cost of the last unit generated, if the demand is at a medium level. In this case the generators cannot supply the demanded quantity at marginal cost prices and the marginal cost of fossil fuel power is too high for the producers to extend the production beyond the hydro power capacity. The ETS price passes onto spot-market price in times of peak demand, that is, when the demand is high enough so that the market clearing price exceeds the cost of switching to fossil fuel power. An interesting property in the NordPool spot market is that the price correlates with the ETS price also in low demand conditions in the summer months. This implies that simple theoretical models of perfect competition provide little insight in the price formation in the NordPool spot market.

The models of imperfect competition with capacity constraints exhibit three properties. *First,* the price correlates strongly with the marginal cost of production of the next unit of output and the generators have a strictly positive price-cost margin for each unit produced in all demand conditions. In the present framework, this result implies *the second property*: The market clearing price is driven by the marginal cost of fossil fuel power, even though the production is to a very significant extent based on hydro and nuclear power. These results combined imply the *third property*: Changes in the production cost of fossil fuel power, such as the price of an ETS allowances, will be passed on to the price of hydro power in full. This occurs under any given demand level, which contradicts the outcome in the models of perfect competition where the price of ETS allowances passes onto the electricity prices only under high demand levels.

The empirical results in the next chapter support the arguments provided in this section. The results establish a positive correlation between emission allowance prices, production capacity and system prices on the spot market under all demand conditions. The result that the price of ETS allowances tend to impose significant upward pressure on electricity prices also on low demand conditions thus implies that the NordPool spot market exhibits the same properties derived in capacity constrained oligopoly models.

It should be, however, noted that these analyses do not provide any causal relationship between the observed prices and strategic behaviour. To establish such causal relationship a researcher should have data on the active plants and preferably on the bids submitted to NordPool by the generators. With these data the researcher might be able to estimate a structural model of competition with real observations and provide more accurate estimates of the actual mechanisms driv-

ing the energy prices. These results would be very useful in predicting the market responses on climate policies and instruments aimed to improve the market efficiency in Nordic countries.[6]

[6]. An example of empirical examination of strategic behaviour in the electricity market can be found, for instance, in Hortacsu and Puller (2005). To conduct similar research on the Nordic market, researchers need detailed time series data on the spot market prices, on the active plants and preferably on the bids submitted to NordPool by the generators. With these data the researcher can estimate a structural model of competition with real observations and provide more accurate estimates of the actual mechanisms driving the energy prices. These results would be very useful in predicting the market responses on potential policies aimed to improve the market efficiency in Nordic countries.

# 4. Econometric analysis of Finnish electricity spot price developments under EU ETS

## 4.1 Introduction

This chapter assesses by means of econometric models how the Finnish wholesale spot price for electricity is influenced by the price of emission allowances in the European emission trade system (EU ETS) alongside other influence factors.

Electricity prices are studied by means of two basic models, one concentrating on the direct effects of fuel costs and emission allowance prices on electricity prices, the other also taking into account capacity and demand considerations.

The current study could not empirically analyse the entire system as depicted in figure 2.6. Instead the analysis concentrates on price formation in the Finnish part of the NordPool *spot market* (figure 4.1, a subset of figure 2.6). Most of the time this market area is integrated with the entire NordPool spot market, but still a significant part of the year (EC DG Competition, 2006) it functions as a separate market due to congestion in the cross-border transmission lines. Furthermore, apart from ignoring the indirect feedbacks via carbon intensity and target achievement (figure 2.6) also the relations between EU ETS and the fossil fuel markets are simplified.

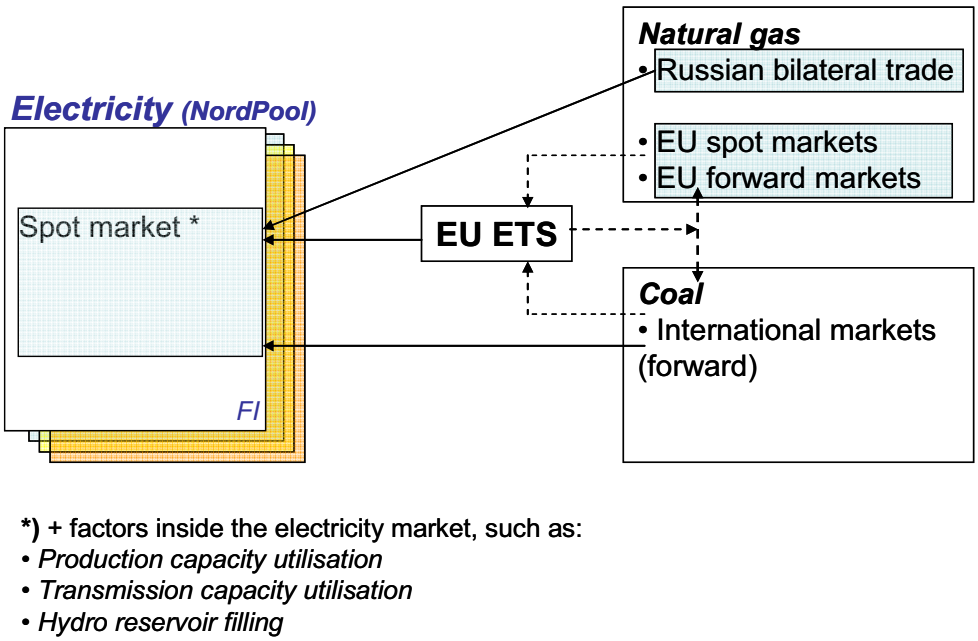


*Figure 4.1. Analysed and considered linkages in this study*

The implication of the focus as depicted in figure 4.1 is that it is assumed that electricity demand on the spot market (per period) is given. This means that it suffices to estimate reduced form equations, with the spot price as dependent variable and the prices of allowances and fossil fuels, as well as of capacity utilisation indicators as explanatory variables.

For the purpose of modelling there are different vantage points for how to perceive the functioning of the electricity market. On the one hand one can consider the electricity market from a strategic viewpoint implying that actual and expected developments of main cost elements are translated into pricing decisions *given* current and expected competitive pressures. In this approach one is interested to identify the main drivers, their relational structure and how for example changes in market regime, available capacity, and in emission abatement strategies would affect wholesale price levels. This approach would require a longer term assessment, i.e. necessitating a series of observation covering at least a few years. It also means one is often interested to analyse both *levels* of key variables and their *changes* (differences between consecutive observations).

On the other hand the price formation of wholesale prices is taking place in a continuous sequence of hourly, daily and longer term adaptations which constitute the equilibration process in the market. For, example daily variations in the EU ETS price cause with some delay adaptations in the wholesale electricity prices. However, simultaneously also other 'disturbances' occur, e.g. changes in fossil fuel prices, the hydro reserve rate, weather induced demand variations, whereas also the wholesale price in a previous period (or periods) in fact signals expectations about the price in the next period (serial correlation).

Next to the different vantage points explained above there are also technical estimation reasons to apply particular kind of the estimation models. Many of the involved data-series can be expected to be non-stationary[7] and hence require the use of more elaborate estimation techniques.

Another point of concern has been the representation of coal and natural gas prices. Both Finnish domestic monthly price series and various European daily price notations for day ahead and forward markets were obtained. In the actual analysis only day ahead and monthly prices have been used. With reference to section 2.3 it can be noted that more elaborate representations of the fossil fuel prices might further improve the representation of fossil fuel cost effects on electricity prices. Crucial is however that such an elaboration most probably does *not affect* the estimated effect of EU ETS (apart from minor changes).

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[7]. Simply stated non-stationary means that the series of consecutive differences between observed and simulated values of a variable is not random, but seems correlated, i.e. shows signs of systematic development (e.g. growing deviation).

## 4.2 Econometric Analysis

From the discussion in chapters 2 and 3 can be inferred that probably significant variables are: emission price in EU ETS, natural gas price, coal price, as well as indicators from within the electricity system (hydro reserve filling, utilisation rate of production capacity, etc.). The various influences on unit-costs and prices are shown in Figure 4.2 (an elaboration of figure 2.1).

Also significant systematic differences in demand levels, such as working day vs. weekend day[8], can be taken into account. Due to anticipatory elements in power capacity allocation these structural demand variations can have implications for the actually available capacity at a certain moment, whereas on the other hand the quality of the demand may differ somewhat.

The daily data on electricity prices, input prices, generation and transmission capacity utilisation, hydro-reservoir filling covers the period 29-12-2003 to 7-5-2006 (861 consecutive days, of which 488 for the EU ETS period). Annex 1 contains more background information on the dataset[9].

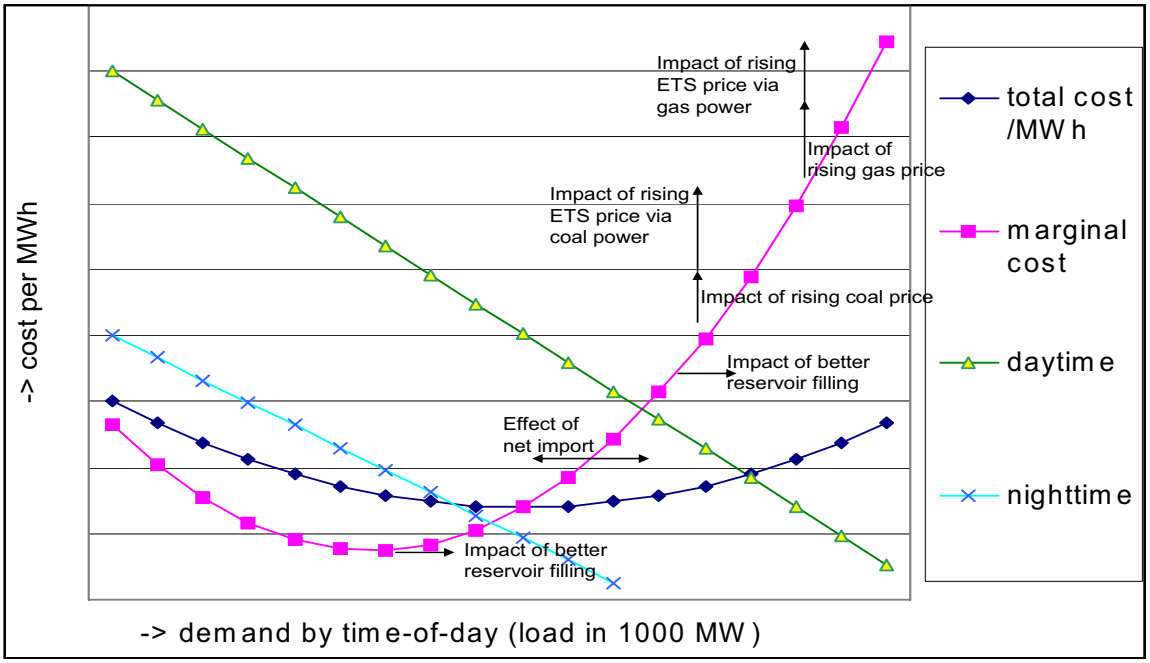


*Figure 4.2. Influences of input characteristics on the wholesale power price*

The time series of variables involved in the analysis were tested on stationarity. In as far as time series were not integrated, they appeared often to be near-

[8]. Some authors suggest skipping of weekend and holiday observations. This may however affect the reliability of those estimation methods in which the serial character of the information is important.

[9]. Not all data are originally observed on a daily basis. Furthermore, also an hourly dataset was constructed. However, the analysis of this very short term behaviour did not provide additional insights.

integrated. The findings are summarised in Annex 2. These findings confirmed the recommendable use of particular kinds of models (see next section).

### 4.2.1 The relationship between electricity prices, allowance prices and fuel prices

We begin the empirical analysis with an error-correction approach. Error correction models are convenient for the simultaneous analysis of long-run, equilibrium relationships between variables as well as for their adjustment to deviations from these equilibria in the short run. Their use can also be motivated with methodological reasons when the time series to be analysed are non-stationary, as is often the case with economic data. Fezzi (2006) has been applying a similar model to the same problem area, albeit for German and English power markets. Here, we concentrate on the direct effect of fuel – coal and gas - and allowance prices on Finnish spot electricity prices in the emission trading period 7.2.2005 to 7.5.2006 in this part of the study. All of these variables appear to be non-stationary when tested at the 1% level, but only the allowance price appears so also at the 5% level.

To facilitate the interpretation of the results, we have transformed coal and gas prices as costs in euro per MWh electricity produced in a condensation plant, the typical marginal unit. The price of allowances is given as euros per MWh for a coal-fired condensation plant. The figure can easily be adjusted for gas-fired plants by using the appropriate emission coefficient (0.8 tonnes of CO2/MWh for a coal-fired condensation plant, 0.48 tonnes CO2/MWh for a gas-fired condensation plant). The main result of this estimation is the following vector error-correction model for the prices of electricity and fuels (results for the full system are reported in Appendix 2):

**Δprice of electricity (at time t) =**

– 0.28** x **(**price of electricity [at time t-1] – 0.83** x price of coal [at time t-1] – 0.61** x price of gas [at time t-1] – 0.93** x allowance price [at time t-1] **)** – 0.14** x Δprice of electricity [at t-1] – 0.17** x Δprice of electricity [at t-2] – 0.06 x Δprice of coal [at t-1] – 0.73 x Δprice of coal [at t-2] – 0.24* x Δprice of gas [at t-1] – 0.13 x Δprice of gas [at t-2] + 0.41 x Δprice of allowance [at t-1] + 1.06 x Δprice of allowance [at time t-2],

where statistical significance at 1 per cent level is indicated by a double asterisk (**) and 5 per cent level by a single asterisk(*).

The equation gives the changes in electricity prices as a function of a long-run relationship between electricity prices and production costs and short-run deviations from this equilibrium relationship. Short-run price changes can also be sluggish to some extent, meaning they may depend on past changes in both electricity and fuel prices.

The long-run equilibrium relation between electricity prices, fuel prices and allowance prices is given by the error-correction term, reported in parenthesis in the first two lines. According to the equation, 93 per cent of allowance prices, 83 per cent of coal prices and 61 per cent of gas prices explain the level of electricity price in the long run. In the short run, however, 28 per cent of changes in the price of electricity are explained by an adjustment to deviations from this long-run equilibrium, 14 per cent by changes in electricity prices in the previous period and 17 per cent in changes in the period prior to that.

Lagged fuel price changes mostly do not have an effect on current electricity price changes. Thus it is the long run relationships and short run pricing dynamics that appear to be driving the results. However, it leaves quite a bit of the short-run dynamics open. In the next section, we turn to possible reasons for short run deviations stemming from demand and capacity utilisation. In particular, we consider the possibility that variations in production capacity utilisation and other features describing the state of the power system affect electricity prices.

### 4.2.2 The relationship between electricity prices and allowance prices while accounting for the state of the power system

A different version of an error correction model (ARIMA[10]) has been used to estimate a model which is purely expressed in terms of differences. A comparable approach has been used by Goto and Yamaguchi (2006) for the Japanese wholesale power market. In this case the prices of natural gas and coal are not included for estimation technical reasons, but on the other hand various power system indicators are included. The selection of variables and time lags is based on preparatory analysis. The shown results for the entire period have the best statistical performance of as larger set of estimations that were carried out. The selected equation for the whole period of emission trading was subsequently applied to separate summer and winter periods to check the volatility of the parameter values in relation to different states of the system.

The equations clarify how much the spot price changes (in €/MWh) as a result of changes in the input variables. The (change in the) price of EU ETS is expressed in €/ton $CO_2$. The WEEKEND dummy equals 1 when the observation is on Saturday or Sunday, and is zero otherwise. The other variables are expressed as frac-

[10]. ARIMA – Autoregressive Integrated Moving Average. (see also Annex 2)

tions, or rather changes in fractions. The fractions lie between 0 and 1, except for the utilisation rate of Swedish-Finnish transmission capacity, which lies between -1 and +1.

The parameter value of 0.85 for EU ETS in the estimation for the whole period means that on average 85% of a single day's price change in EU ETS ends up in the spot price of the next day. For the second equation the comparable parameter has a value of 0.76. In principle one would expect that the parameter value of EU ETS in equation II is higher than in equation I, since in equation II the observations are drawn from a period with higher demands (loads). For a combination of reasons (e.g. less dramatic price movements in the included period) the parameter value turns out to be somewhat lower than in equation I. Yet, the confidence intervals have a significant overlap, and hence the parameter values do not differ essentially. On the other hand, for the summer period (no.III) the parameter value is much lower (0.39) and in fact does not pass the 95% significance test. All in all the most value should be attached to the estimation which covers the entire period (no.I).

The estimation results for the entire period show that in particular the utilisation rate of production capacity (both of the current and the previous day) plays an important role, implying that higher loads cause higher prices. As could be expected well filled reservoirs have a moderating price effect (negative sign), but the extent to which Finland can actually benefit from well filled hydro-reservoirs is also influenced by the utilisation of cross-border transmission capacity. Considering the parameter values (124.5 and 53.9 vs. 2.36) one can note that the latter variable has much less influence than the utilisation rate of Finnish production capacity. The estimation results for the summer period illustrate that in periods with lower load levels the sensitivity of the spot price for any of the cost factors reduces appreciably.

**I. Whole period (447 observations)**

**Δprice of electricity [at time t] =**

0.51 + 0.59 x Δprice of electricity [t-1] + 0.26 x Δprice of electricity [t-2] + 0.85 x Δprice of EU ETS[t-1] – 0.25 x Δhydro-reservoir filling[t-1] + 124.52 x Δutilisation rate of production capacity[t] + 53.91 x Δutilisation rate of production capacity[t-1] + 2.36 x Δutilisation rate of Swedish-Finnish transmission capacity[t] – 1.71 x WEEKEND dummy

All variables are significant at 95% level

**II. September 2005 – May 2006 ('winter', 249 observations)**

**Δprice of electricity [at time t] =**

0.27 + 0.66 x Δprice of electricity [t-1] + 0.22 x Δprice of electricity [t-2] + 0.76 x Δprice of EU ETS[t-1] – 0.50 x Δhydro-reservoir filling[t-1] + 147.63 x Δutilisation rate of production capacity[t] + 47.52 x Δutilisation rate of production capacity[t-1] + 3.37 x Δutilisation rate of Swedish-Finnish transmission capacity[t] – 1.29 x WEEKEND dummy

Most variables are significant at 95% level, except the intercept, WEEKEND and Swedish-Finnish transmission capacity.

**III. May 2005 – September 2005 ('summer', 160 observations)**

**Δprice of electricity [at time t] =**

0.41 + 0.39 x Δprice of electricity [t-1] + 0.32 x Δprice of electricity [t-2] + 0.39 x Δprice of EU ETS[t-1] – 0.09 x Δhydro-reservoir filling[t-1] + 110.02 x Δutilisation rate of production capacity[t] + 64.0 x Δutilisation rate of production capacity[t-1] + 1.14 x Δutilisation rate of Swedish-Finnish transmission capacity[t] – 1.50 x WEEKEND dummy

Only price of electricity (t-1 and t-2) production capacity utilisation (t and t-1), and WEEKEND significant are at 95% level.

In order to provide an impression of the performance of the estimated function figure 4.3 shows the observed and simulated values of the Finnish spot price based on equation I above. In the picture the changes in the price of electricity (Δprice of electricity [at time t] in the above equations) are transformed back into levels, given a known starting level of the electricity price (in the picture abbreviated to 'pelfin').

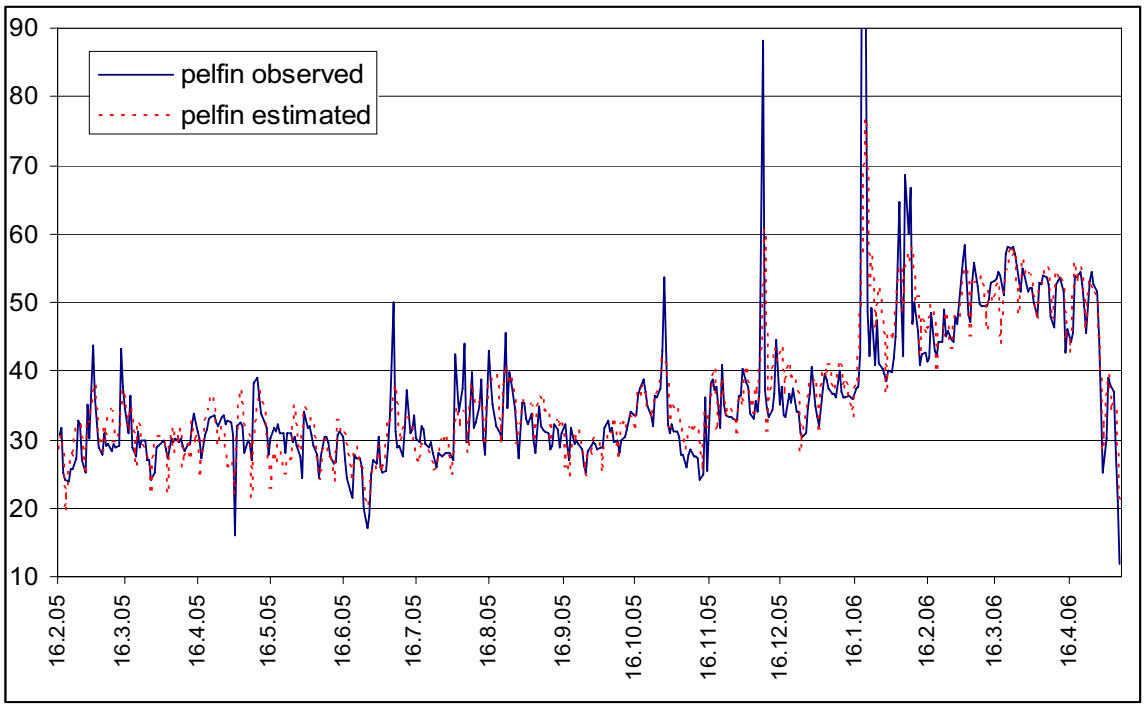


*Figure 4.3. Comparison of observed and estimated electricity prices (pelfin) for the Finnish NordPool area using the ARIMA model (in €/MWh)*

### 4.2.3 The relationship between electricity prices, allowance prices and fossil fuel prices while accounting for the state of the power system

In the estimation approach reported in this section the *level* of the electricity price is related to *levels* of explanatory variables. In this case all types of influence factors, EU ETS allowances, fossil fuel cost, utilisation of capacity, etc. are included in as far as appearing statistically significant. Estimating levels instead of differences can encounter technical difficulties resulting in low reliabilities of some parameter values. Based on the results of the previous estimates there is however already a notion of what is highly significant, possibly significant and usually insignificant. Furthermore by using the natural logarithms of the observed values and applying yet again another estimation approach (AR-GARCH [11]) useful estimates for levels can be obtained. Garcia et al (2005) has been using the same estimation method to model day-ahead prices in the Spanish wholesale power market, albeit partly with other type of data.

Eventually, after testing a larger selection, the following variables were taken into account:

[11]. AR-GARCH – Autoregression – Generalised Autoregressive Conditional Heteroskedasticy.

*Explanatory variables*

- utilisation rate of Finnish production capacity – *prcautd*
- utilisation rate of the transmission link with Sweden – *impsutil* [12]
- deviation from the median aggregate NordPool area hydro reservoir filling – *hydrodev*
- daily price of EU ETS 2006 – *ETS06*
- monthly price of natural gas in Finland for very large users – *pmgas*
- deviation[13] from the average long term daily temperature in Finland – *dev-temp*
- dummy for weekend days – *WEEKEND*
- dummy for holidays that are not in a weekend – *HOLI*

*Dependent variable*

- Finnish NordPool area spot price (daily average) – *pelfin*

Other variables, such as the coal price have been tested, but turned out to be not statistically significant in the setting of *this* model [14]. The utilisation rate of the transmission capacity with Russia was sometimes significant, but not in the key results presented here.

Just as for the ARIMA estimations in section 4.1.2 estimations were made for the entire period, as well as for summer and winter periods separately. However, the estimations for the shorter periods did produce less satisfactory results, and are therefore not discussed here. The terms ($pelfin$[t-1] – $\overline{pelfin}[t-1]$) and ($pelfin$[t-2] – $\overline{pelfin}[t-2]$) in the presented equation below refer to the differences between observed and simulated values for the electricity price one and two periods back. The other correction terms cannot be interpreted so straightforwardly, but are also less important in the current context.

As most variables are expressed in terms of natural logarithms of the original value the influence of a change in one of the explanatory variables cannot be straightaway read from the parameter values. Furthermore, the error correction terms indicate that an initial shock is followed by (small) secondary adaptations. Yet, also in this case it is obvious that the state of the power system affects the

[12]. For variables that can include negative values (impsutil, devtemp, hydrodev) a conditional formulation was included to avoid division by zero when using the natural logarithm.

[13]. Based on the average of measurements in five locations in South and South-Central Finland.

[14]. This result contradicts the previous findings in the error correction model, where coal prices were significant variables. One plausible explanation for this is that the error correction model did not account for demand and capacity related variables, and therefore, the coal price variable captured some of these effects which are significant in the AR-GARCH model.

sensitivity of the spot price with respect to passing on input cost, *including* the price of EU ETS emission allowances. In the next section (4.3) will be illustrated on the basis of the estimated function below what the price effects of EU ETS can be in different situations.

**Whole period** (447 observations; legend of variables names: see previous page)

**ln(*pelfin*[at time t]) =**

2.14 + 0.46 x ln(*ETS06*[t-1]) + 0.26 x ln(*pmgas*[t-30] – 0.02 x ln(*hydrodev*[t-1]) + 1.51 x ln(*prcautd*[t]) – 0.35 x ln(*prcautd*[t-1]) + 0.006 x ln(*impsutil*[t] – 0.009 x ln(*devtemp*[t-1]) – 0.02 x WEEKEND – 0.15 x HOLI – 0.55 x (*pelfin*[t-1] – $\overline{pelfin}[t-1]$) – 0.16 x (*pelfin*[t-2] – $\overline{pelfin}[t-2]$)

+ 0.003 x ARCH0 + 1.01 x ARCH1 + 0.15 x GARCH1

All variables are significant at 95% level, except 'impsutil' (Swedish-Finnish cross-border capacity) for which it is approx. 94%.

In order to provide an impression of the performance of the estimated function figure 4.4 shows the observed and simulated values of the Finnish spot price ('pelfin') based on the above equation.

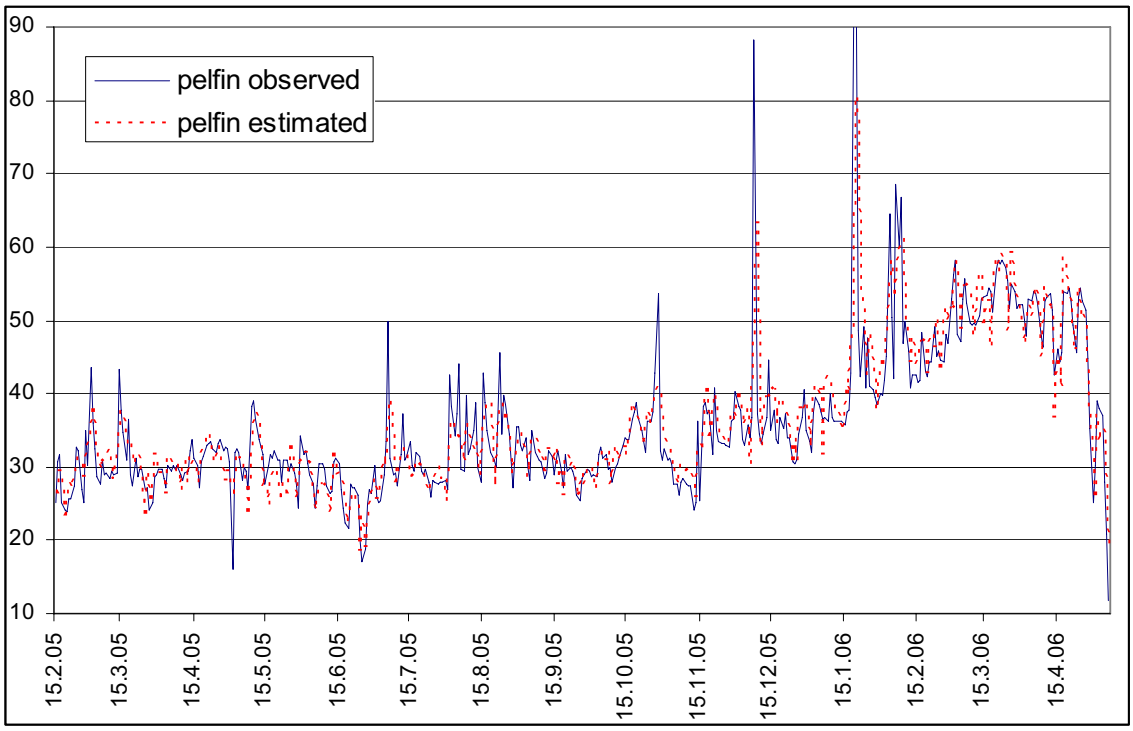


*Figure 4.4. Comparison of observed and estimated electricity prices (€/MWh) for the Finnish NordPool area using the AR-GARCH model*

## 4.3 Summary of the estimation results

The three estimation methods used are complementary to each other, as each is able to capture a part of the influence factors, while each of the methods deals with technical estimation pitfalls in a different way. The estimation results together indicate a fairly narrow bandwidth for the degree of passing on of the cost of EU ETS, thereby allowing for sufficiently confident conclusions. Two main messages emanate from the estimation results:

1. during the period analysed *on average* about 75% to 95% of the price change in EU ETS ended up in the Finnish NordPool spot price[15];

2. the state of the power system, as characterised in particular by the utilisation level of domestic generation capacity and in addition by other features such as the filling of the hydro reserve, influences the sensitivity of the spot price with respect to input cost, *including* the allowance price in EU ETS.

The entire set of results from sections 4.2.1 to 4.2.3 fit well into the international bandwidth of 60%~100% which is reported for passing on EU ETS price rises (e.g. Sijm et al., 2006).

The results of the level estimates presented in section 4.2.3 allow us to simulate to what extent the passing on of EU ETS allowance prices varies when the state of the power system varies (and hence the wholesale price level). Typical states of the system, typified by the variables for the estimation of Finnish NordPool area spot price levels, have been applied to arrive at a certain 'baseline spot price' (prior to inserting a price rise for EU ETS). The typical values and resulting baseline electricity spot prices are summarised in Annex 3. The key results are presented below.

Subsequently single day increases of 12%, 25% and 50% were inserted for the EU ETS price, assuming a baseline level of € 21.30 per ton (the average price during the period analysed). The results are summarised in table 4.1. For example, if the price of ETS allowances increases by 25% (in one day) during an autumn day with typical medium loads (~10000 MW) the Finnish spot price is expected to rise by 0.94 x 25%, which amounts to 5 €/MWh. The results are quite near to what is implied by the estimations in the sections 4.2.1 and 4.2.2. Overall the level based calculations tend to indicate somewhat higher shares passed on. Considering the prevailing load levels at which a major part of the electricity is generated and traded, the estimation results for levels would imply that the overall average share passed on lies in the neighbourhood of 95%.

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[15]. If only the estimation results for the entire EU ETS period (16 months) are taken into consideration the bandwidth narrows down to 85%~95%.

*Table 4.1. Shares of the rise of the EU ETS allowance price passed immediately on to the spot price for different single day ETS price increases for different typical load levels*

| | **low loads** | **medium loads** | **high loads** |
|---|---|---|---|
| **dETS in %** | share of dETS passing | share of dETS passing | share of dETS passing |
| **12 %** | 0.47 | 0.97 | 1.11 |
| **25 %** | 0.45 | 0.94 | 1.07 |
| **50 %** | 0.43 | 0.89 | 1.02 |

According to table 4.1 higher loads imply higher shares of EU ETS price increases passed on to the spot price. To a certain extent these higher load levels correspond to an increased use of fossil fuels in the marginally offered units (see also chapter 2) and hence an increased need for covering emissions with allowances. On the other hand higher load levels correspond with gradually reducing levels of competition, and consequently better possibilities to increase prices. The current analysis can not give any indication regarding relative influence of both elements. The results also suggest that the larger the price change of an EU ETS allowance (in one day) the smaller the share that is passed on.

The presented indications for the extent to which the prices of EU ETS are passed on in the wholesale electricity prices reflect a situation of the past, even though the recent past. This historic picture probably gives a reasonable indication for the extent of passing on the EU ETS prices in electricity spot prices in the nearby future, but after a couple of years relations may change due to significant changes in the incentive structure (i.e. either the relative strength of relations in figure 2.6 and/or their structure changes).

As was demonstrated, price sensitivity shows seasonal variations. From Figure 4.5 can be inferred that the carbon intensity of Finnish generation has been varying substantially during 2005 (the first year of EU ETS) and seems to repeat a similar pattern in 2006, albeit at a seemingly(?) [16] higher level of carbon intensity than in 2005. It is however also evident that the carbon intensity stays clearly below the levels of the pre-EU ETS year 2004.

[16]. However to assess that precisely the monthly fossil fuel input should weighed by its carbon content.

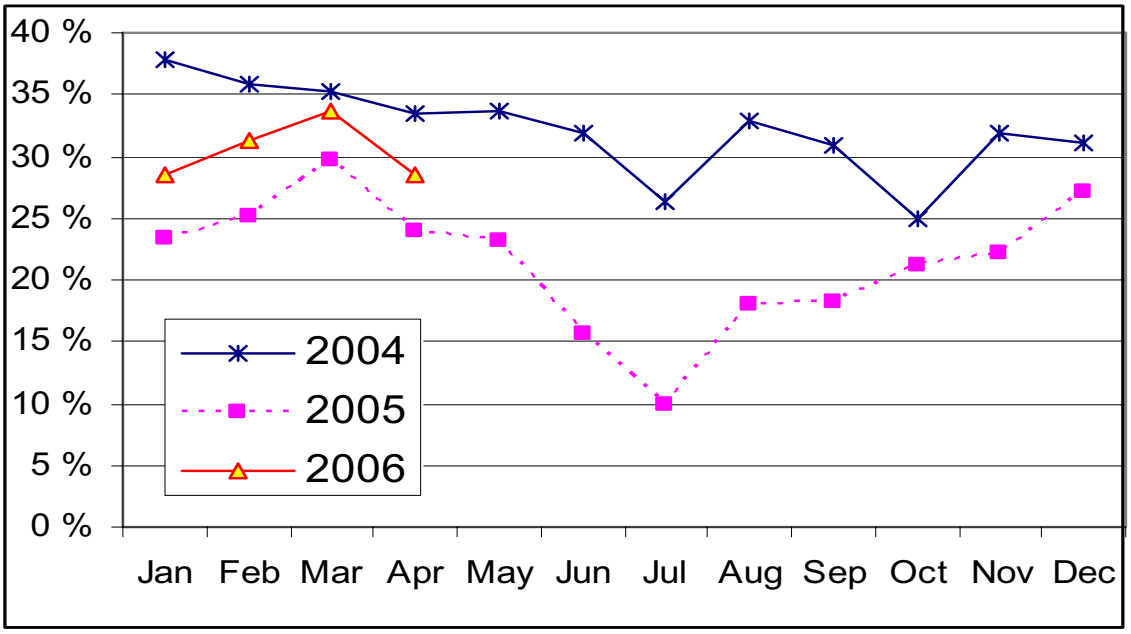


*Figure 4.5. Approximate shares of fossil fuel based electricity generation (incl. peat) in total domestic production in Finland (source: Adato)*

The question whether the passing on of EU ETS price increases is large can also be related to the extent to which electricity is actually generated by means of fossil fuels (fig. 4.5). This is in particular relevant when the initial allocation allowances are grandfathered instead of auctioned. As such the observed spot price rises are the simply product of a liberalised electricity market and cannot be deemed automatically as intently overcharged due to market power. Such a judgement would need much more elaborate and detailed analysis. However considering a share of fossil fuels of well below 50%, the cost increase due to EU ETS has been exceeded by the compensation in spot prices.

# 5. Conclusions

There are theoretical explanations why EU ETS allowance price rises can cause price rises in the electricity market. Empirical analysis of Finnish electricity markets in recent years indicates that the price rises can be significant despite a share of fossil fuels in domestic generation of well below 50%. On average about 75% to 95% of a price change in EU ETS is passed on to the Finnish NordPool spot price.

These effects are just a logic market outcome and do not necessarily imply imperfect competition in the electricity markets. At least in the near term future developments of fuel prices and EU ETS allowance prices will be closely related. Together these rising input cost do truly represent a significant cost effect. The fact that capacity utilisation appears to affect the sensitivity of the spot price for input cost indicates that – other things being equal – future increases in demand for electricity will probably exacerbate the price effects of EU ETS.

The extent to which capacity utilization is driven by strategic behaviour in an imperfectly competitive spot market requires a more detailed analysis. The theoretical explanations clarify how market power can be established and be used to increase prices above a competitive equilibrium level. We should, however, observe that in practice such prices can emerge also in perfectly competitive markets due to high demand combined with little remaining capacity.

The electricity spot price would – in all likelihood – be less affected by price rises of EU ETS allowances if more generation capacity would be installed. This effect is not straightforward, however, as it depends on the particularities of market mechanisms driving the price formation in NordPool. Any policy recommendations should therefore be based on a structural econometric analysis of the generators' behaviour in the spot market.

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# Annex 1 – Background information on the datasets

For the econometric assessment data were obtained from:

- NordPool (daily and hourly observations for power prices, production, consumption, import/export for the years 2000-2006;
- Nordel (reservoir filling);
- Statistics Finland (Finnish monthly wholesale prices of natural gas and coal);
- Argus (daily f.o.b. coal prices for Baltic harbour destinations)**;**
- Heren Energy (Zeebrugge node daily natural gas prices for day ahead and forward markets);
- Finnish Meteorological Institute (daily average temperature and the deviation from the long term average for each day).

Two datasets were constructed for the period 29-12-2003 to 7-5-2006. One contains daily records (861 consecutive days). The other contains three typical hourly observations per day, being low load, daily plateau, and peak hour (2583 records).

Further data transformations and estimations were carried out in SAS ©

# Annex 2 – Background information on the estimation approaches

## Stationarity tests

Augmented Dickey-Fuller tests on stationarity were conducted. In conjunction with the preparation of the ARIMA estimations also spectral analysis has been carried out. Table A1 provides an overview of the results and figure A1 presents the various price series.

**Table A1.** *Indications for stationary or non-stationary series per variable (based on augmented Dickey-Fuller test) for the period 7.2.2005-7.5.2006*

**Null Hypothesis: ETS06 (EU ETS06 price) has a unit root**
Exogenous: Constant
Lag Length: 1 (Automatic based on SIC, MAXLAG=17)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -2.221779 | 0.1989 |
| Test critical values: | 1% level | -3.443607 | |
| | 5% level | -2.867279 | |
| | 10% level | -2.569889 | |

*MacKinnon (1996) one-sided p-values.

Augmented Dickey-Fuller Test Equation
Dependent Variable: D(ETS06)
Method: Least Squares
Date: 07/07/06 Time: 12:43
Sample(adjusted): 3 487
Included observations: 485 after adjusting endpoints

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| PCO2(-1) | -0.009050 | 0.004073 | -2.221779 | 0.0268 |
| D(PCO2(-1)) | 0.384986 | 0.042296 | 9.102148 | 0.0000 |
| C | 0.151993 | 0.068961 | 2.204032 | 0.0280 |

| | | | |
|---|---|---|---|
| R-squared | 0.154524 | Mean dependent var | 0.013245 |
| Adjusted R-squared | 0.151016 | S.D. dependent var | 0.526158 |
| S.E. of regression | 0.484804 | Akaike info criterion | 1.396022 |
| Sum squared resid | 113.2868 | Schwarz criterion | 1.421904 |
| Log likelihood | -335.5354 | F-statistic | 44.04654 |
| Durbin-Watson stat | 1.973699 | Prob(F-statistic) | 0.000000 |

**Null Hypothesis: PELFIN (Finnish NordPool spot price) has a unit root**
Exogenous: Constant
Lag Length: 5 (Automatic based on SIC, MAXLAG=17)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -3.039680 | 0.0320 |
| Test critical values: | 1% level | -3.443719 | |
| | 5% level | -2.867329 | |
| | 10% level | -2.569916 | |

*MacKinnon (1996) one-sided p-values.

Augmented Dickey-Fuller Test Equation
Dependent Variable: D(PELFIN)
Method: Least Squares
Date: 07/07/06 Time: 12:44
Sample(adjusted): 7 487

Included observations: 481 after adjusting endpoints

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| PELE(-1) | -0.090115 | 0.029646 | -3.039680 | 0.0025 |
| D(PELE(-1)) | -0.317017 | 0.050002 | -6.340104 | 0.0000 |
| D(PELE(-2)) | -0.341809 | 0.050658 | -6.747345 | 0.0000 |
| D(PELE(-3)) | -0.234257 | 0.051260 | -4.569950 | 0.0000 |
| D(PELE(-4)) | -0.184672 | 0.048705 | -3.791655 | 0.0002 |
| D(PELE(-5)) | -0.161607 | 0.045734 | -3.533645 | 0.0005 |
| C | 3.217812 | 1.072154 | 3.001260 | 0.0028 |

| | | | |
|---|---|---|---|
| R-squared | 0.205058 | Mean dependent var | 0.032256 |
| Adjusted R-squared | 0.194996 | S.D. dependent var | 6.639364 |
| S.E. of regression | 5.956972 | Akaike info criterion | 6.421448 |
| Sum squared resid | 16820.13 | Schwarz criterion | 6.482219 |
| Log likelihood | -1537.358 | F-statistic | 20.37835 |
| Durbin-Watson stat | 2.029378 | Prob(F-statistic) | 0.000000 |

**Null Hypothesis: PDCOAL has a unit root**
Exogenous: Constant
Lag Length: 7 (Automatic based on SIC, MAXLAG=17)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -3.315321 | 0.0147 |
| Test critical values: | 1% level | -3.443776 | |
| | 5% level | -2.867354 | |
| | 10% level | -2.569929 | |

*MacKinnon (1996) one-sided p-values.

§Augmented Dickey-Fuller Test Equation
Dependent Variable: D(PDCOAL)
Method: Least Squares
Date: 07/07/06 Time: 12:45
Sample(adjusted): 9 487
Included observations: 479 after adjusting endpoints

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| PCOAL(-1) | -0.020843 | 0.006287 | -3.315321 | 0.0010 |
| D(PCOAL(-1)) | -0.001053 | 0.043360 | -0.024294 | 0.9806 |
| D(PCOAL(-2)) | -0.001053 | 0.043360 | -0.024294 | 0.9806 |
| D(PCOAL(-3)) | -0.001053 | 0.043360 | -0.024294 | 0.9806 |
| D(PCOAL(-4)) | -0.001053 | 0.043360 | -0.024294 | 0.9806 |
| D(PCOAL(-5)) | -0.000633 | 0.044302 | -0.014294 | 0.9886 |
| D(PCOAL(-6)) | -0.000633 | 0.044302 | -0.014294 | 0.9886 |
| D(PCOAL(-7)) | 0.316580 | 0.044302 | 7.145955 | 0.0000 |
| C | 0.307766 | 0.094736 | 3.248681 | 0.0012 |

| | | | |
|---|---|---|---|
| R-squared | 0.116364 | Mean dependent var | -0.007127 |
| Adjusted R-squared | 0.101323 | S.D. dependent var | 0.164093 |
| S.E. of regression | 0.155558 | Akaike info criterion | -0.864986 |
| Sum squared resid | 11.37319 | Schwarz criterion | -0.786604 |
| Log likelihood | 216.1642 | F-statistic | 7.736625 |
| Durbin-Watson stat | 2.004882 | Prob(F-statistic) | 0.000000 |

**Null Hypothesis: PDGAS has a unit root**
Exogenous: Constant
Lag Length: 2 (Automatic based on SIC, MAXLAG=17)

| | | t-Statistic | Prob.* |
|---|---|---|---|
| Augmented Dickey-Fuller test statistic | | -2.945929 | 0.0410 |
| Test critical values: | 1% level | -3.443635 | |
| | 5% level | -2.867292 | |
| | 10% level | -2.569896 | |

*MacKinnon (1996) one-sided p-values.

Augmented Dickey-Fuller Test Equation

Dependent Variable: D(PDGAS)
Method: Least Squares
Date: 07/07/06 Time: 12:46
Sample(adjusted): 4 487
Included observations: 484 after adjusting endpoints

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| PD_GAS(-1) | -0.052651 | 0.017873 | -2.945929 | 0.0034 |
| D(PD_GAS(-1)) | -0.181900 | 0.044566 | -4.081617 | 0.0001 |
| D(PD_GAS(-2)) | -0.260362 | 0.044057 | -5.909726 | 0.0000 |
| C | 0.652537 | 0.248224 | 2.628823 | 0.0088 |

| | | | |
|---|---|---|---|
| R-squared | 0.120989 | Mean dependent var | 0.003718 |
| Adjusted R-squared | 0.115495 | S.D. dependent var | 2.708266 |
| S.E. of regression | 2.547073 | Akaike info criterion | 4.715997 |
| Sum squared resid | 3114.039 | Schwarz criterion | 4.750560 |
| Log likelihood | -1137.271 | F-statistic | 22.02269 |
| Durbin-Watson stat | 1.950655 | Prob(F-statistic) | 0.000000 |

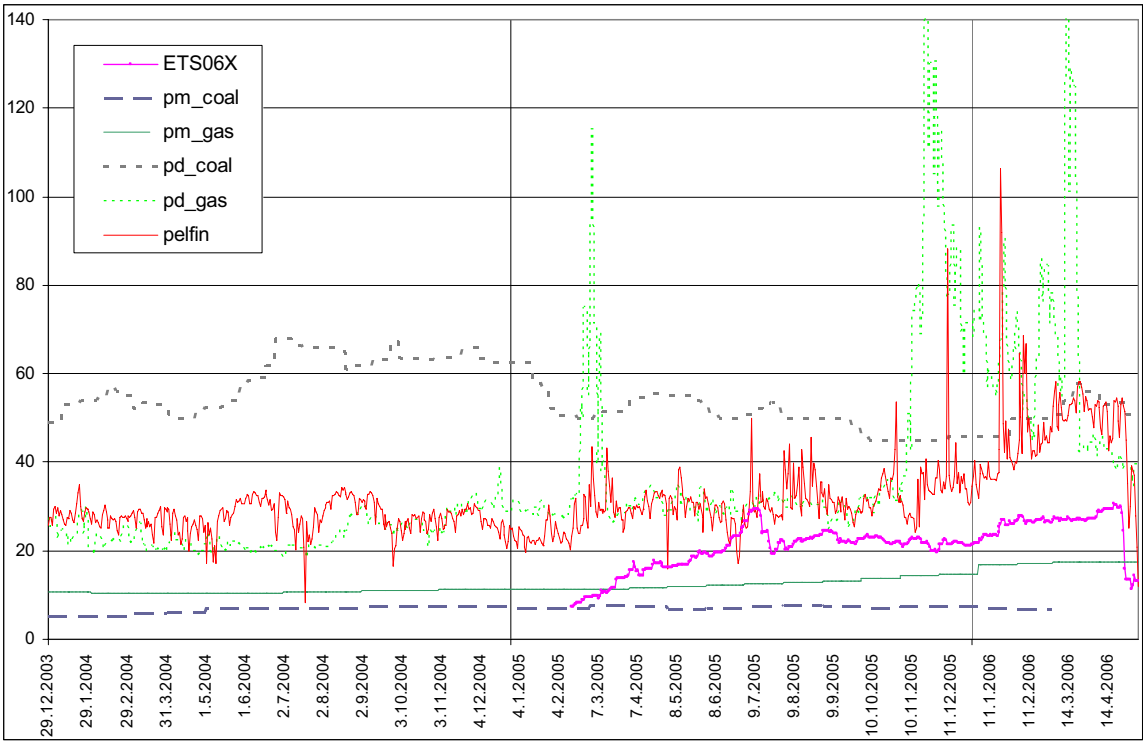


*Figure A1. Prices of natural gas, coal, EU ETS and Finnish spot price*

*Legend to figure A1:*

pm_gas: monthly average natural gas price for very large users in Finland (€/MWh)

pd_gas: daily gas price on Zeebrugge node (Western European price; £/Therm)

pm_coal: monthly average coal price for very large users in Finland (€/MWh)

pd_coal: import price for Baltic ports (f.o.b.) (€/ton)

ETS06: daily price in EU ETS for December 2006 deliverable allowances (€/ton)

pelfin: daily average spot price in Finnish NordPool area

## Error-correction model estimation results

The use of vector error correction model implied the estimation of a set of equations. The relevant parameters for electricity price as dependent variable are in the column headed by CointEq1 and continuing under D(PELE).

**Vector Error Correction Estimates**
Date: 07/07/06 Time: 11:53
Sample(adjusted): 4 487
Included observations: 484 after adjusting endpoints
Standard errors in ( ) & t-statistics in [ ]

| Cointegrating Eq: | CointEq1 | | | |
|---|---|---|---|---|
| PELE(-1) | 1.000000 | | | PELE = pelfin |
| PCO2(-1) | -0.930223 | | | PCO2 = ETS06 |
| | (0.16833) | | | |
| | [-5.52608] | | | |
| PDCOAL(-1) | -0.838609 | | | |
| | (0.18368) | | | |
| | [-4.56558] | | | |
| PDGAS(-1) | -0.614732 | | | |
| | (0.14566) | | | |
| | [-4.22035] | | | |
| **Error Correction:** | **D(PELE)** | **D(PCO2)** | **D(PDCOAL)** | **D(PDGAS)** |
| CointEq1 | -0.281633 | -0.004202 | -0.000171 | 0.015206 |
| | (0.04057) | (0.00337) | (0.00113) | (0.01774) |
| | [-6.94259] | [-1.24542] | [-0.15112] | [ 0.85713] |
| D(PELE(-1)) | -0.142931 | 0.002600 | 0.000382 | -0.029820 |
| | (0.04809) | (0.00400) | (0.00134) | (0.02103) |
| | [-2.97210] | [ 0.64999] | [ 0.28501] | [-1.41792] |
| D(PELE(-2)) | -0.166946 | 0.001156 | 0.000863 | -0.011554 |
| | (0.04467) | (0.00372) | (0.00124) | (0.01954) |
| | [-3.73715] | [ 0.31122] | [ 0.69337] | [-0.59143] |
| D(PCO2(-1)) | 0.412241 | 0.381713 | 0.032391 | 0.080414 |
| | (0.56176) | (0.04672) | (0.01566) | (0.24567) |
| | [ 0.73383] | [ 8.17027] | [ 2.06899] | [ 0.32733] |
| D(PCO2(-2)) | 1.059319 | -0.008161 | -0.017529 | -0.017212 |
| | (0.56381) | (0.04689) | (0.01571) | (0.24656) |
| | [ 1.87887] | [-0.17406] | [-1.11562] | [-0.06981] |
| D(PDCOAL(-1)) | -0.058894 | -0.090417 | 0.000509 | -0.160577 |
| | (1.64328) | (0.13666) | (0.04580) | (0.71862) |
| | [-0.03584] | [-0.66159] | [ 0.01112] | [-0.22345] |
| D(PDCOAL(-2)) | 0.725529 | -0.016833 | 0.003502 | 1.432720 |
| | (1.63861) | (0.13628) | (0.04567) | (0.71659) |
| | [ 0.44277] | [-0.12352] | [ 0.07668] | [ 1.99937] |
| D(PDGAS(-1)) | -0.239250 | 0.012934 | -0.001691 | -0.203941 |
| | (0.10151) | (0.00844) | (0.00283) | (0.04439) |
| | [-2.35685] | [ 1.53201] | [-0.59762] | [-4.59403] |
| D(PDGAS(-2)) | -0.135051 | 0.002306 | 0.002310 | -0.280258 |
| | (0.10170) | (0.00846) | (0.00283) | (0.04447) |
| | [-1.32798] | [ 0.27265] | [ 0.81495] | [-6.30171] |

| | | | | |
|---|---|---|---|---|
| R-squared | 0.226333 | 0.154907 | 0.012151 | 0.116251 |
| Adj. R-squared | 0.213303 | 0.140673 | -0.004486 | 0.101366 |
| Sum sq. resids | 16371.02 | 113.2318 | 12.71475 | 3130.825 |
| S.E. equation | 5.870717 | 0.488245 | 0.163609 | 2.567335 |
| F-statistic | 17.36989 | 10.88350 | 0.730355 | 7.810334 |
| Log likelihood | -1538.893 | -335.2255 | 193.9498 | -1138.572 |
| Akaike AIC | 6.396250 | 1.422419 | -0.764255 | 4.742034 |
| Schwarz SC | 6.474016 | 1.500185 | -0.686489 | 4.819800 |
| Mean dependent | 0.028289 | 0.013107 | -0.007053 | 0.003718 |
| S.D. dependent | 6.618922 | 0.526694 | 0.163243 | 2.708266 |
| Determinant Residual Covariance | | 1.445565 | | |
| Log Likelihood | | -2818.073 | | |
| Log Likelihood (d.f. adjusted) | | -2836.242 | | |
| Akaike Information Criteria | | 11.88530 | | |
| Schwarz Criteria | | 12.23092 | | |

## ARIMA model estimation results

A MA(2) model turned out to produce the best results for the daily time series for the entire EU-ETS period. The same application has also been used for the estimation of winter and summer periods[17] separately. In the ARIMA procedure a series can be shifted backward n steps (in fact implying n lags), alternatively also lags can be indicated. In the presentation below both ‘lags’ and ‘shifts’ should be understood as lags (see also legend on the next page).

---

```
                         The ARIMA Procedure

                 Conditional Least Squares Estimation
                 Dependent Variable    Δpelfin(t-1)

                             Standard                 Approx
Parameter      Estimate         Error   t Value   Pr > |t|    Lag   Variable   Shift
MU              0.50554       0.18606      2.72     0.0068      0   p_elfin        0
MA1,1           0.59491       0.04644     12.81     <.0001      1   p_elfin        0
MA1,2           0.25871       0.04659      5.55     <.0001      2   p_elfin        0
NUM1            0.84791       0.15793      5.37     <.0001      0   ETS06          1
NUM2          124.51869      10.03069     12.41     <.0001      0   prcautd        0
NUM1,1         53.90647      10.51501      5.13     <.0001      1   prcautd        0
NUM3           -0.25137       0.08552     -2.94     0.0035      0   hydrofil       1
NUM4            2.36431       1.15711      2.04     0.0416      0   impsutil       1
NUM5           -1.71305       0.64195     -2.67     0.0079      0   weekend        0


                      Constant Estimate       0.505539
                      Variance Estimate       25.65298
                      Std Error Estimate      5.064877
                      AIC                     2721.719
                      SBC                     2758.622
                      Number of Residuals          446
               * AIC and SBC do not include log determinant.


                   Correlations of Parameter Estimates

    Variable             p_elfin    p_elfin    p_elfin      ETS06    prcautd
    Parameter                 MU      MA1,1      MA1,2       NUM1       NUM2
    p_elfin         MU     1.000      0.004      0.029      0.012     -0.096
    p_elfin      MA1,1     0.004      1.000     -0.798     -0.035      0.026
    p_elfin      MA1,2     0.029     -0.798      1.000      0.011     -0.056
    ETS06         NUM1     0.012     -0.035      0.011      1.000     -0.071
    prcautd       NUM2    -0.096      0.026     -0.056     -0.071      1.000
    prcautd     NUM1,1     0.162      0.042     -0.023     -0.066      0.648
    hydrofil      NUM3     0.113      0.008      0.061      0.012     -0.079
    impsutil      NUM4    -0.213      0.029     -0.051     -0.213      0.152
    weekend       NUM5    -0.981     -0.002     -0.027     -0.034      0.106


          Correlations of Parameter Estimates (continued)

         Variable            prcautd   hydrofil   impsutil    weekend
         Parameter            NUM1,1       NUM3       NUM4       NUM5
         p_elfin         MU    0.162      0.113     -0.213     -0.981
         p_elfin      MA1,1    0.042      0.008      0.029     -0.002
         p_elfin      MA1,2   -0.023      0.061     -0.051     -0.027
         ETS06         NUM1   -0.066      0.012     -0.213     -0.034
         prcautd       NUM2    0.648     -0.079      0.152      0.106
         prcautd     NUM1,1    1.000     -0.055      0.223     -0.165
         hydrofil      NUM3   -0.055      1.000     -0.182     -0.092
         impsutil      NUM4    0.223     -0.182      1.000      0.226
         weekend       NUM5   -0.165     -0.092      0.226      1.000
```

---

[17]. Winters are defined as including the months November to March. Summers are defined as including the months May to September.

```
                    Outlier Detection Summary

               Maximum number searched         20
               Number found                     7
               Significance used             0.05

                          Outlier Details

                                                                 Approx
                                                        Chi-      Prob>
Obs     Time ID       Type                 Estimate    Square     ChiSq
711     12/08/2005    Additive             46.58340    278.31    <.0001
753     01/19/2006    Additive             44.35017    271.19    <.0001
754     01/20/2006    Additive             33.38419    153.72    <.0001
556     07/06/2005    Additive             14.44690     30.15    <.0001
773     02/08/2006    Additive             14.19470     29.81    <.0001
670     10/28/2005    Additive             13.23970     26.26    <.0001
771     02/06/2006    Additive             12.27706     24.24    <.0001
```

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**Legend:**

| | |
|---|---|
| **prcautd** | utilisation rate of Finnish production capacity |
| **impsutil** | utilisation rate of the transmission link with Sweden |
| **hydrofil** | NordPool area hydro reservoir filling rate |
| **ETS06** | daily price of EU ETS 2006 |
| **WEEKEND** | dummy for weekend days (1 if Saturday or Sunday; 0 otherwise) |
| **p_elfin** | Finnish NordPool area spot price (daily average) |
| MAn,m | moving average term – $n^{th}$ difference, m period(s) back |
| NUMn,m | instrumental variable - $n^{th}$ difference, m period(s) back |

## AR-GARCH model estimation results

For the levels estimation an AR(1 2)-GARCH(1,1) model turned out to produce the best results for the daily time series for the entire EU-ETS period. The same application has also been used for the estimation of winter and summer periods[18] separately.

- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

The AUTOREG Procedure

Dependent Variable lnpelfin

Ordinary Least Squares Estimates (1ST step))

| | | | |
|---|---|---|---|
| SSE | 6.83347975 | DFE | 437 |
| MSE | 0.01564 | Root MSE | 0.12505 |
| SBC | -539.22725 | AIC | -580.25283 |
| Regress R-Square | 0.7670 | Total R-Square | 0.7670 |
| Durbin-Watson | 1.0943 | | |

| Variable | DF | Estimate | Standard Error | t Value | Approx Pr > \|t\| |
|---|---|---|---|---|---|
| Intercept | 1 | 1.8890 | 0.1477 | 12.79 | <.0001 |
| lnimpsutil | 1 | 0.009324 | 0.004249 | 2.19 | 0.0287 |
| lnets06lag | 1 | 0.4350 | 0.0331 | 13.13 | <.0001 |
| lnhydrodevlag | 1 | -0.0486 | 0.005319 | -9.13 | <.0001 |
| lnprcaut | 1 | 1.2899 | 0.1567 | 8.23 | <.0001 |
| lnprcautlag | 1 | -0.4146 | 0.1488 | -2.79 | 0.0056 |
| lnpmgaslag | 1 | 0.3213 | 0.0729 | 4.41 | <.0001 |
| lndevtemp | 1 | -0.0134 | 0.004887 | -2.75 | 0.0062 |
| weekend | 1 | -0.0579 | 0.0154 | -3.77 | 0.0002 |
| HOLI | 1 | -0.0961 | 0.0431 | -2.23 | 0.0262 |

Estimates of Autocorrelations

```
Lag   Covariance    Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1
  0       0.0153       1.000000   |                    |********************|
  1      0.00643       0.420553   |                    |********            |
  2      0.00375       0.245541   |                    |*****               |
```

Preliminary MSE 0.0125

Estimates of Autoregressive Parameters

| Lag | Coefficient | Standard Error | t Value |
|---|---|---|---|
| 1 | -0.385465 | 0.047779 | -8.07 |
| 2 | -0.083433 | 0.047779 | -1.75 |

Algorithm converged.

GARCH Estimates (2nd step)

| | | | |
|---|---|---|---|
| SSE | 5.73727576 | Observations | 447 |
| MSE | 0.01284 | Uncond Var | . |
| Log Likelihood | 377.149386 | Total R-Square | 0.8044 |
| SBC | -662.76039 | AIC | -724.29877 |
| Normality Test | 1030.0184 | Pr > ChiSq | <.0001 |

[18]. Winters are defined as including the months November to March. Summers are defined as including the months May to September.

| Variable | DF | Estimate | Standard Error | t Value | Approx Pr > \|t\| |
|---|---|---|---|---|---|
| Intercept | 1 | 2.1393 | 0.2361 | 9.06 | <.0001 |
| lnimpsutil | 1 | 0.005681 | 0.003065 | 1.85 | 0.0638 |
| lnets06lag | 1 | 0.4597 | 0.0416 | 11.04 | <.0001 |
| lnhydrodevlag | 1 | -0.0196 | 0.007278 | -2.70 | 0.0070 |
| lnprcaut | 1 | 1.5069 | 0.0792 | 19.02 | <.0001 |
| lnprcautlag | 1 | -0.3531 | 0.0916 | -3.85 | 0.0001 |
| lnpmgaslag | 1 | 0.2577 | 0.1017 | 2.54 | 0.0112 |
| lndevtemp | 1 | -0.007006 | 0.003509 | -2.00 | 0.0459 |
| weekend | 1 | -0.0236 | 0.009641 | -2.45 | 0.0143 |
| HOLI | 1 | -0.1543 | 0.0148 | -10.45 | <.0001 |
| AR1 | 1 | -0.5499 | 0.0584 | -9.42 | <.0001 |
| AR2 | 1 | -0.1610 | 0.0493 | -3.27 | 0.0011 |
| ARCH0 | 1 | 0.003665 | 0.000814 | 4.51 | <.0001 |
| ARCH1 | 1 | 1.0052 | 0.1458 | 6.89 | <.0001 |
| GARCH1 | 1 | 0.1454 | 0.0755 | 1.92 | 0.0543 |

**Legend of variable names**

**prcautd** utilisation rate of Finnish production capacity

**impsutil** utilisation rate of the transmission link with Sweden

**hydrodev** deviation from the median aggregate NordPool area hydro reservoir filling

**ETS06** daily price of EU ETS 2006

**pmgas** monthly price of natural gas in Finland for very large users

**devtemp** deviation from the average long term daily temperature in Finland

**WEEKEND** dummy for weekend days (1 if Saturday or Sunday; 0 otherwise)

**HOLI** dummy for holidays that are not in a weekend (1 for holidays outside weekends, 0 otherwise)

**pelfin** Finnish NordPool area spot price (daily average)

ARn autoregression term for $n^{th}$ lag

ARCHn autoregressive conditional heteroskedasticy term for $n^{th}$ lag

# Annex 3. – Typical input values and wholesale prices for the pass-through assessment

The inserted levels are based on distribution of the observed series in the period 7.2.2005 – 7.5.2006. For the units of the various variables see Annex 1. A medium load is not to be regarded as the median or average load, but rather a (non peak) day time load outside the summer period.

| *Variable names ** | medium load | low load | high load |
|---|---|---|---|
| **impsutil** (fraction) | -0.050 | -1.223 | 0.947 |
| **imprutil** (fraction) | 0.830 | 0.830 | 0.948 |
| **ets06[t-1]** (€/ton $CO_2$) | 21.300 | 21.300 | 21.300 |
| **hydrodev[t-1]** (fraction) | -4.700 | -19.888 | 10.015 |
| **prcautd[t-1]** (fraction) | 0.700 | 0.440 | 0.840 |
| **prcautd[t]** (fraction) | 0.700 | 0.440 | 0.840 |
| **pmgas[t-30]** (€/MWh) | 12.440 | 12.440 | 12.440 |
| **devtemp[t] (degrees Celsius)** | 0.380 | 10.500 | -16.700 |
| **weekend** (dummy) | 0.285 | 1.000 | 0.000 |
| **holi** (dummy) | 0.015 | 1.000 | 0.000 |
| **pelfin (calculated)** (€/MWh) | 22.400 | 46.3 | 52.9 |
| **Δ ETS 12% in euros** | 2.560 | 2.56 | 2.56 |
| **Δ ETS 25% in euros** | 5.330 | 5.33 | 5.33 |
| **Δ ETS 50% in euros** | 10.650 | 10.65 | 10.65 |
| **Δ pelfin due to ΔETS 12% (€)** | 1.200 | 2.47 | 2.83 |
| **Δ pelfin due to ΔETS 25% (€)** | 2.420 | 5.00 | 5.72 |
| **Δ pelfin due to ΔETS 50% (€)** | 4.600 | 9.49 | 10.84 |

*) Legend on the next page

When calculating the overall average share of ETS06 price increases passed on to the spot price, the following weights are applied.

| | medium load | low load | high load |
|---|---|---|---|
| **Δ pelfin due to ΔETS 12% (€)** | 0.04 | 0.20 | 0.20 |
| **Δ pelfin due to ΔETS 25% (€)** | 0.04 | 0.20 | 0.20 |
| **Δ pelfin due to ΔETS 50% (€)** | 0.04 | 0.04 | 0.04 |

**Legend of variable names**

| | |
|---|---|
| **prcautd** | utilisation rate of Finnish production capacity |
| **impsutil** | utilisation rate of the transmission link with Sweden |
| **hydrodev** | deviation from the median aggregate NordPool area hydro reservoir filling |
| **ETS06** | daily price of EU ETS 2006 |
| **pmgas** | monthly price of natural gas in Finland for very large users |
| **devtemp** | deviation from the average long term daily temperature in Finland |
| **WEEKEND** | dummy for weekend days (1 if no Saturday or Sunday; 0 otherwise) |
| **HOLI** | dummy for holidays that are not in a weekend (1 for holidays outside weekends, 0 otherwise) |
| **pelfin** | Finnish NordPool area spot price (daily average) |

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