How does the EU Emission Trade System augment electricity wholesale prices?

The slippery steps from indications to evidence

Adriaan Perrels, Ville Mälkönen, Juha Honkatukia

Government Institute for Economic Research
P.O: Box 1271
00101 Helsinki
phone: +358 7032972
fax: +358 7032968
e-mail: adriaan.perrels@vatt.fi

Abstract

The establishment of the EU Emission Trade System (EU ETS) has intensified both the political and the economic research discourse concerning market imperfections and their implications for price formation in wholesale electricity markets, and more specifically to what extent EU ETS is exacerbating these effects.
At a conceptual level it is rather straightforward to explain why EU ETS is likely to raise wholesale electricity prices in liberalised power markets, but it is less straightforward to produce reliable quantitative evidence. Earlier econometric work on electricity price developments in liberalised wholesale markets tends to focus on (shorter term) volatilities in prices and/or has a rather partial nature. During a recent study concerning the influence of EU ETS on price formation in Nordic wholesale power markets it became quite clear that too narrow a focus may be misleading. Yet, this means that the choice of the appropriate econometric model merits careful consideration, since both shorter and longer history processes play a role. Furthermore, issues were raised regarding the representative value of alternative time series for essentially the same variables (but measured in different geographic and time scales). This paper discusses the issues and possible choices and illustrates various points with results from the VATT study.

Key words

Electricity market, electricity prices, emission trade, market power, pass-through

JEL codes: C22, D4, L1, L9, Q21, Q41

1. Introduction

Even though occasionally some studies may have mentioned the possibility of larger impacts on electricity prices, the majority of the assessment studies for various EU countries assumed a generic cost level rise for electricity generation commensurate to the emission allowance price or emission tax rate and weighted by the carbon intensity of generation. Only when EU ETS drew nearer to its implementation some studies emerged that tried to produce more specific quantified assessments of cost effects for selected sectors (Quirion 2003, Grubb 2004, Koljonen and Kekkonen 2005).

Once the European Emission Trade System (EU ETS) had come into operation it surprised many specialists as prices went well beyond 20 and even 25 euros per ton of CO_2. Furthermore, these higher than anticipated prices seemed to pass through quickly and by and large wholly into the wholesale electricity prices in various electric power market areas. This sparked off an array of econometric studies on price formation of emission allowances (e.g. Bentz, and Trück, 2005; as well as on the pass through of emission allowance prices into product prices, notably electricity and energy intensive materials (Demailly and Quirion, 2006; Smale et al. 2006; Sijm et al. 2006, Fezzi 2006).

The study discussed in this article also belongs to the latter category of econometric assessments of the pass-through of the allowance prices of EU ETS[1]. However, there are some important differences between this study and the above mentioned studies. First, the period covered is longer. Second, the Nordic power system differs both in terms of generation mix and in terms of market structure from the single country market areas in Western-Europe. Third, the local gas market is rather rudimentary compared to Western-Europe.

An as such separate issue, which however ties in with the level of feasible pass-through, is the degree of market imperfections in the considered wholesale market. For a long time the Nordic wholesale power market served via NordPool was regarded as well functioning and with relatively mild or few signs of market power. This picture has been gradually eroded. Various publications have hinted at ever more signs of an increasing occurrence of market power in the NordPool area and its constituent parts (European Commission DG Competition 2006; von der Fehr et al 2005; Perrels and Kemppi 2003). Market power enhances the possibilities to pass on the prices of allowances into the wholesale price of electricity. As in any system the load level has a significant impact on the actually feasible degree of market power in the short run (e.g. hour or day). Additionally, the prominent position of hydro power in NordPool introduces a medium term factor (e.g. month or quarter) with respect to actually feasible degree of market power, since lower (than average) reservoir levels increase the option value of hydro power. Consequently, the merit order of units not only varies by typical daily and weekly load level but also periodically (with a varying non-prefixed length) during the year. The consequence is that the estimations have to allow for the occurrence of – an unknown and probably varying degree of – market power and hence inclusion of momentary scarcity indicators (capacity utilisation rates) could really make a difference.

All in all it meant that there was not an a priori obviously superior specification and estimation approach. Furthermore, the considerations above implied that there was leeway regarding the choice of data that supposedly would be the best representation of certain variables.

The rest of this paper is organised as follows. In section 2 a brief overview of the recent developments regarding price levels and production in the NordPool area is presented. Subsequently, section 3 considers the possible interactions between EU ETS, fossil fuel markets, and the Nordic wholesale power market and their implications for *feasible* estimations of the pass-through of EU ETS prices. Section 4 deals with the estimations, whereas section 5 provides some concluding remarks.

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[1] . The study was carried out for the ministry of Trade and Industry (see Honkatukia et al, 2006)

2. Key features of the Nordic and Finnish electricity market

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.

The merit order is such that hydro power, nuclear power, and industrial and district heat CHP 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 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. According to a recent investigation commissioned by the European Commission this situation of an own price area occurs fairly frequently, i.e. about 40% of the monthly time in some months (European Commission DG Competition 2006). 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.

Coal condensing power, gas based peak power under certain conditions other gas combined cycle function as the marginal capacity and are usually decisive for the resulting price in the NordPool area. However, in periods of low demand and abundant hydro reserves no Finnish condensing power may be in use, meaning that at such moments there may be only some fossil fuel input in CHP units and consequently spot prices can be low (e.g. under 30 €/MWh). Table 1 provides an overview of the installed generation capacity in Finland and the other NordPool countries. Also the transmission capacity between Nord-Pool 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 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. Furthermore, a part of the Finnish hydro power is run of river capacity without a reservoir. Some of the Finnish non-CHP fossil fuel capacity was mothballed during at least a part of the study period. 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 1.

Table 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	-

Bio-fuels are predominantly used in CHP units. Peat is to some extent also co-fired in bio-fuel units.

*) 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

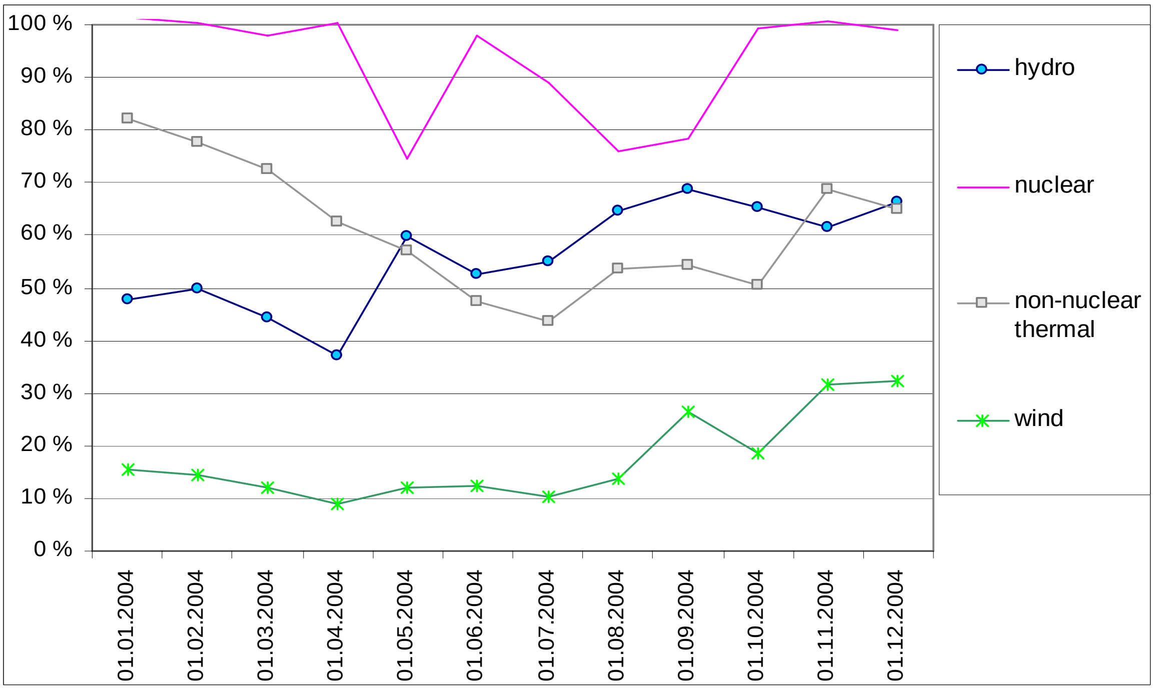

Figure 1. *Utilisation rates by month of various types of capacity in the Finnish system in 2004 (source: Nordel)*

Consumption and production show daily, weekly and annual cycles (figure 2). 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.

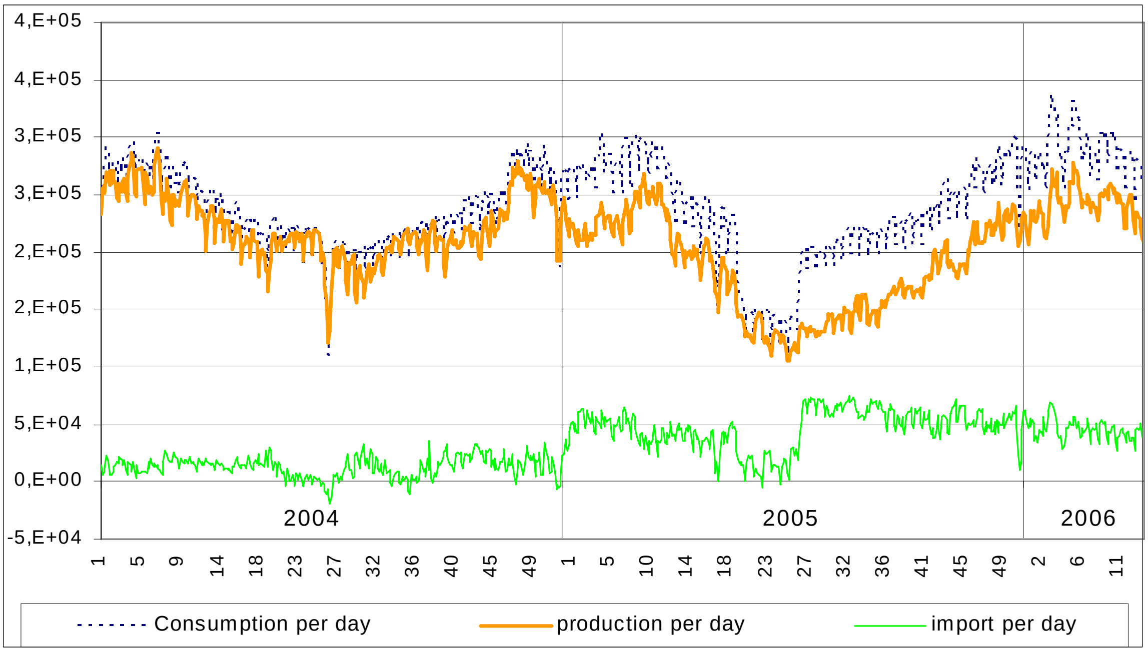

Figure 2. *Daily consumption and production of electricity in Finland and daily net import to Finland in MWh (x 100.000) (numbers along the x-axis denote sequence numbers of weeks; source: NordPool)*

Figure 3 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. During the year 2004 and even more so during 2005 the hydro reservoir filling came back to long term average levels (after very low levels in 2002 and 2003).

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 Finnish import prices for coal and monthly prices for large scale consumers of natural gas in Finland. It should be stressed that the prices for internationally traded natural gas in Western Europe hovered at higher levels and showed more volatility.

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

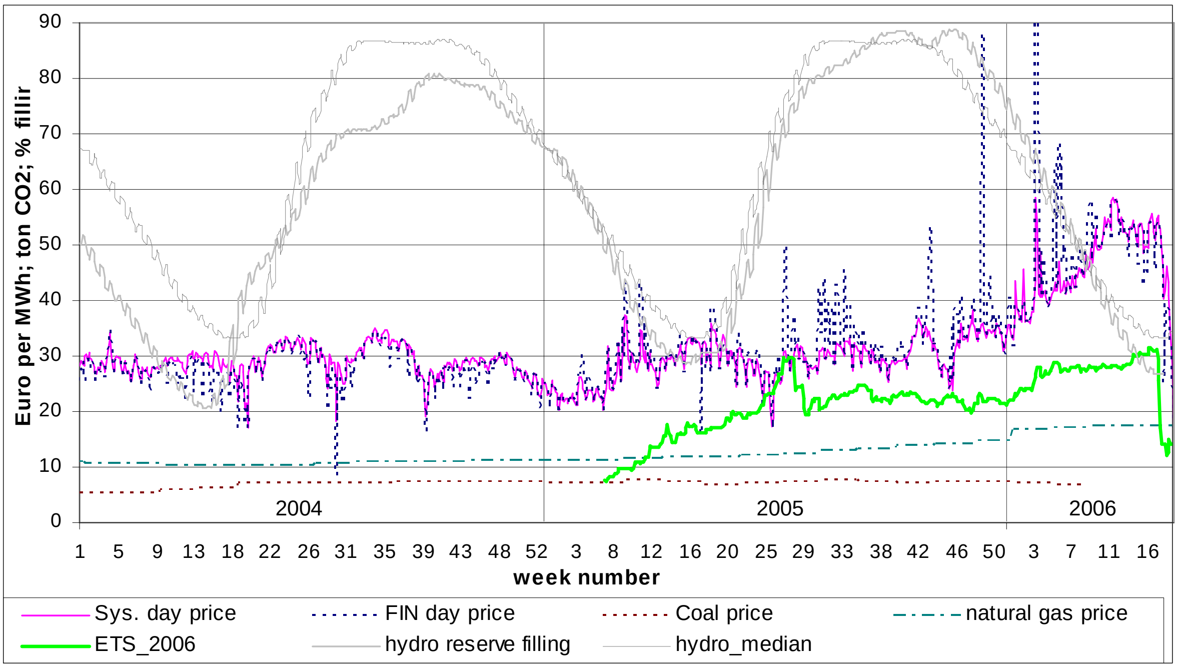

Figure 3. *Development of key factors in the Finnish wholesale electricity market*[2]

3. Interactions between EU ETS, fossil fuel markets and NordPool

The price developments of EU ETS allowances and wholesale electricity as shown in figure 3 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 in theory, 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 wholesale markets for energy products (figure 4), whose price formation is interlinked, but not identical. In this case also the links between the spot market and forward/bilateral markets within NordPool are important. For example, distributors can decide to buy more via longer term forward contracts in order to shed risks of EU

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[2] . 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.

ETS induced price peaks. In response generators may decide to be more cautious in charging very high spot prices.

Another issue is that the prices of fossil fuels 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. On the other hand depending on the level of the allowance prices in EU ETS and the price difference between coal and gas there may be still leverage left for gas based generators to raise the offer price in Nordpool. Also the differences in operational flexibility between gas and coal can affect this leverage mechanism.

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. 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 principal alternative 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.

There are still other background factors such as the degree to which the electricity and heat markets are interconnected in the various NordPool areas and the expectation regarding target fulfilment of the power sector in EU ETS.

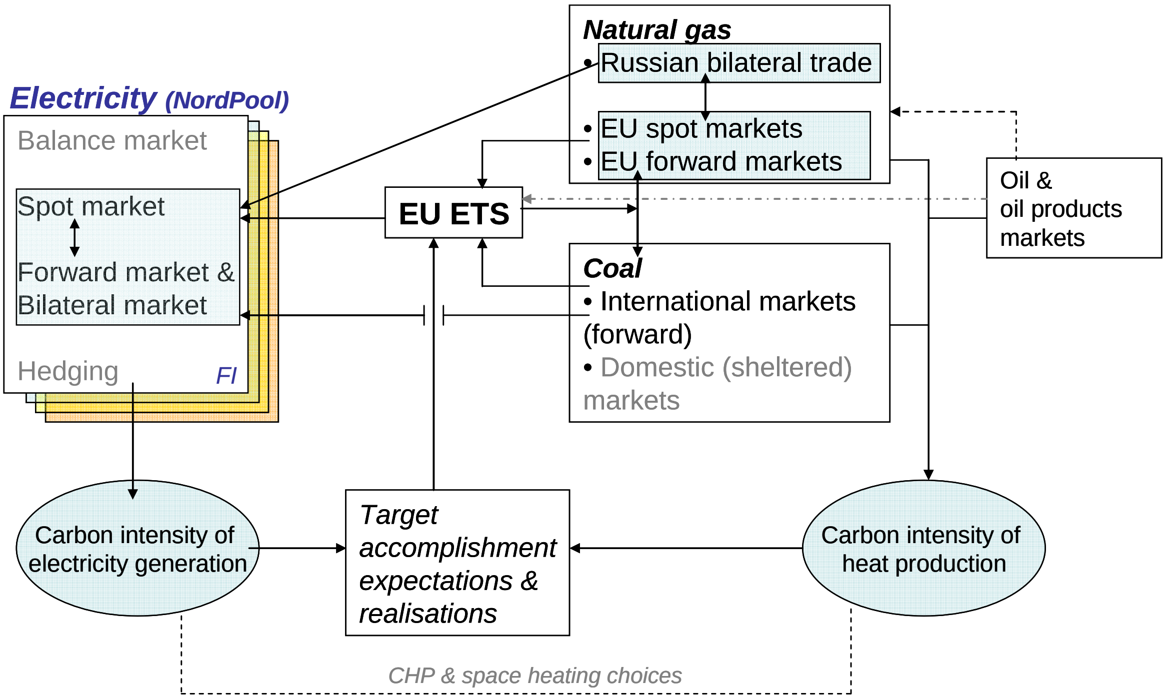


Figure 4. *Direct and indirect linkages between fossil fuel markets, EU ETS, and electricity markets*

Newberry (2006) demonstrates with a theoretical model how leverage effects can work to provide for example gas based generators with market power or conversely how more intricate games may emerge depending on the merit order of individual coal and gas units. In Finland coal is by far the most prominent fuel for covering elevated load demands. Nevertheless it is possible that a kind of contestable market has emerged in which gas usually represents the upper reference limit of unit-cost even though it may be a theoretical option in many cases.

The above considerations underscore that in fact a more comprehensive study of the entire set of related markets would be the best approach, but in the present study we had to confine ourselves to some extent.

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. The level of analysis would be daily or weekly data, whereas use of hourly data may put too much stress on the short run effects. It also would mean that preferably both supply and demand functions would be estimated in order to avoid limiting assumptions (see e.g. Fezzi and Bunn, 2006).

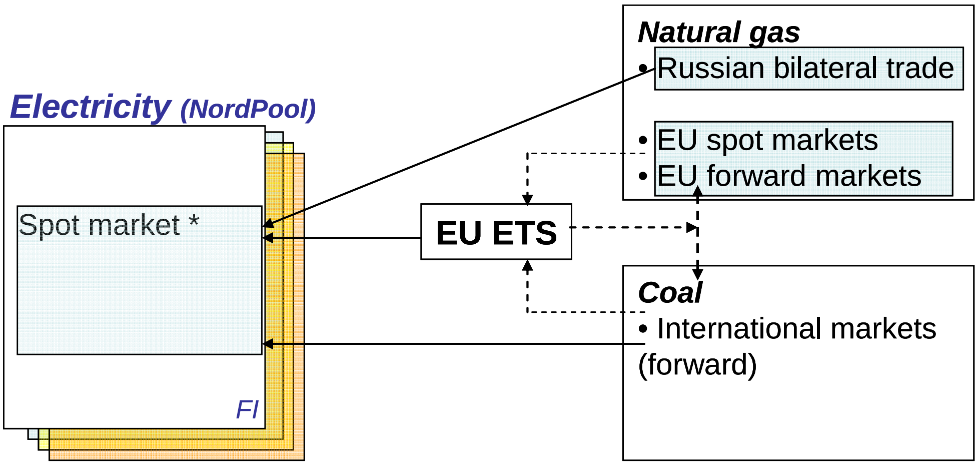
On the other hand the price formation of wholesale prices is taking place in a continuous sequence of hourly, daily and longer term adaptations which constitute the equilibration process in the market. For, example daily variations in the EU ETS price cause with some delay adaptations in the wholesale electricity prices. However, simultaneously also other ‘disturbances’ occur, e.g. changes in fossil fuel prices. In this case there is particular focus on serial correlation.

In summary the following possibly relevant factors were identified:

- NordPool spot price for Finland in preceding periods
- variable input cost, such as:
    - fuel prices, with and/or without lags
    - price of EU ETS allowances (for December 2006 deadline) with and/or without lags
- utilisation rate of capacity (production, international transmission)
- Nordpool area hydro reserve filling
- variation in demand composition (weekdays versus working days)

Relevant issues would also be the expectations on target fulfilment and planned capacity extensions. For the current set of estimations these have not been included. Yet, in the definition of capacity utilisation in the data set prefixed seasonal variations in capacity have been taken into account to some extent.

Figure 5 below summarises what relations have been included in the analysis. The analysis concentrates on price formation in the Finnish part of the NordPool spot market. 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. Apart from ignoring the indirect feedbacks via carbon intensity and target achievement also the relations between EU ETS and the fossil fuel markets are simplified. The implication of the focus as depicted in figure 5 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.



***)** + factors inside the electricity market, such as:
- *Production capacity utilisation*
- *Transmission capacity utilisation*
- *Hydro reservoir filling*

Figure 5. *Analysed and considered linkages in this study*

4. Econometric Analysis

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)[3]. Annex 1 contains more background information on the dataset.

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-integrated.

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[3] Not all data are originally observed on a daily basis. For example, the EU ETS prices only have working day notations, whereas the reservoir filling is interpolated from weekly data (this may be a source of biases, see e.g. Sijm 2006).

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.). Also significant systematic differences in demand levels, such as working day vs. weekend day, can be taken into account. Due to anticipatory elements in power capacity allocation these structural demand variations have implications for the actually available capacity at a certain moment[4].

Three types of models have been used. A vector error correction model (VECM), an autoregressive moving average model (ARMA), and an autoregressive general autoregressive conditional heteroskedasticity model (AR-GARCH). The VECM model concerns a set of equations for the Finnish electricity spot price, the EU ETS 2006 price, the (Western European) coal price and the (Western European) natural gas price (see Annex 1 for more details on the data and data sources). In the other estimations Finnish monthly gas and monthly and weekly coal prices have been used.

4.1 Estimations with the VECM model

The VECM model concentrates on the direct effects 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, and the price of allowances as euros per tonne CO_2 in a coal-fired condensation plant. The main result of this estimation is the following error-correction model for the prices of electricity and fuels as can be found in the first column with figures in table 2.

The error-correction term (the upper part of table 2) gives the long-run equilibrium relation between electricity prices, fuel prices and allowance prices. According to the equation, 93 per cent of allowance prices (ETS06[-1]), 83 per cent of coal prices (PDCOAL[-1]) and 61 per cent of gas prices (PDGAS[-1] explain the electricity price. In the short run, 28 per cent of the electricity price change is explained by an adjustment to deviations from this long-run equilibrium (CointEq), a bit over 14 per cent by the changes in electricity prices in the previous period (D(PELFIN(-1)) and approximately 17 per cent in changes in the period prior to that (D(PELFIN(-2)).

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[4] Some authors suggest skipping of weekend and holiday observations. However in case of serial correlation for data at daily observation level, this can easily cause other biases.

Table 2. *Vector Error Correction Model Estimates*

Sample(adjusted): 4 487
Included observations: 484 after adjusting endpoints

Cointegrating Eq:	CointEq1	Standard error	t-statistics
PELFIN(-1)	1.000000		
ETS06(-1)	-0.930223	(0.16833)	[-5.52608]
PDCOAL(-1)	-0.838609	(0.18368)	[-4.56558]
PDGAS(-1)	-0.614732	(0.14566)	[-4.22035]

Error Correction:	**D(PELFIN)**	D(ETS06)	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(PELFIN(-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(PELFIN(-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(ETS06(-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(ETS06(-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

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. We assume that low levels of actually available remaining capacity[5] enhance market power for the owners of the remaining available capacity. The implication could be that absence of separate variables for capacity utilisation may cause that the parameter values for variable input cost such as fuel and EU ETS to be overstated.

4.2 Estimations with the ARMA model

In this case the prices of natural gas and coal are not included as we preferred to include as much as possible Finland specific data. The selection of variables and time lags is based on preparatory analysis. The shown results for the entire period have the best statistical performance. The selected specification 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 (seasonal) 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 fractions, 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.

Table 3. *ARMA model estimates for three periods*

	7.02.2005 7.05.2006 **daily average price** **N = 447**	**1.09.2005 7.05.2006** **daily average price** **N = 249**	**summer period 2005** **daily average price** **N = 160**
	all parameters significant at 95% level	parameters rated with ** significant at 95% level; * denotes 90% level	parameters rated with ** significant at 95% level; * denotes 90% level
intercept	0,5055	0,2740	* 0,4126
MA-dpelfin[t-1]	0,5949	** 0,6608	** 0,3859
MA-dpelfin[t-2]	0,2587	** 0,2177	** 0,3247
dimpsutil	2,3643	* 3,3685	1,1439
dets06[t-1]	0,8479	** 0,7653	0,39338
dhydrofil[t-1]	-0,2514	** -0,4978	-0,0924
dprcautd	124,5187	** 147,6389	** 110,0194
drcautd[t-1]	53,9065	** 47,5283	** 64,0025
WEEKEND	-1,7131	-1,2919	** -1,5035

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[5] . That is the capacity which is not yet producing but immediately available to supply to the grid.

Legend to table 3:

dpelfin – first differences in Finnish spot price between consecutive days
dets06 – first differences in daily EU-ETS prices for the December 2006 allowances
dimpsutil – first differences in daily utilisation rate of Finnish-Swedish transmission capacity
dhydrofil – first differences of daily reservoir filling ratio for the entire NordPool area
dprcautd – first differences in daily utilisation rate of Finnish production capacity
WEEKEND – dummy for weekend days (1 if Saturday or Sunday, 0 otherwise)

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 the second equation is higher than in the first, since in the second equation the observations are drawn from a period with higher demands (loads). For a combination of reasons (e.g. less dramatic price movements, etc.) the parameter value turns out to be somewhat lower. Possibly also changes in the merit order by season and the gaming related to merit order as hinted at by Newberry (2006) matter in this case. Also the larger value of the parameter for production capacity utilisation in the second equation hints at a state of the market in there is more opportunity to exercise market power. Yet, we should not forget that the confidence intervals of the parameters of dets06 in both equations have a significant overlap.

For the summer period (3rd equation) the parameter value is much lower (0.39) and in fact does not pass the 95% significance test. Notwithstanding the lower significance of various variables the summer period seems to confirm the hypothesis that the basic (seasonal) state of the system matters for the extent that wholesale prices absorb changes in input cost.

The estimation results for the entire period show that in particular the utilisation rate of production capacity (both of the current (prcautd) and the previous day (prcautd[-1]) plays an important role, implying that higher loads cause higher prices as such, as well as indirectly by enabling higher sensitivity for (other input cost). As could be expected well filled reservoirs (hydrofil) 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 (impsutil). 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.

The performance of the first equation is also shown in figure 6, in which simulated and observed values are compared.

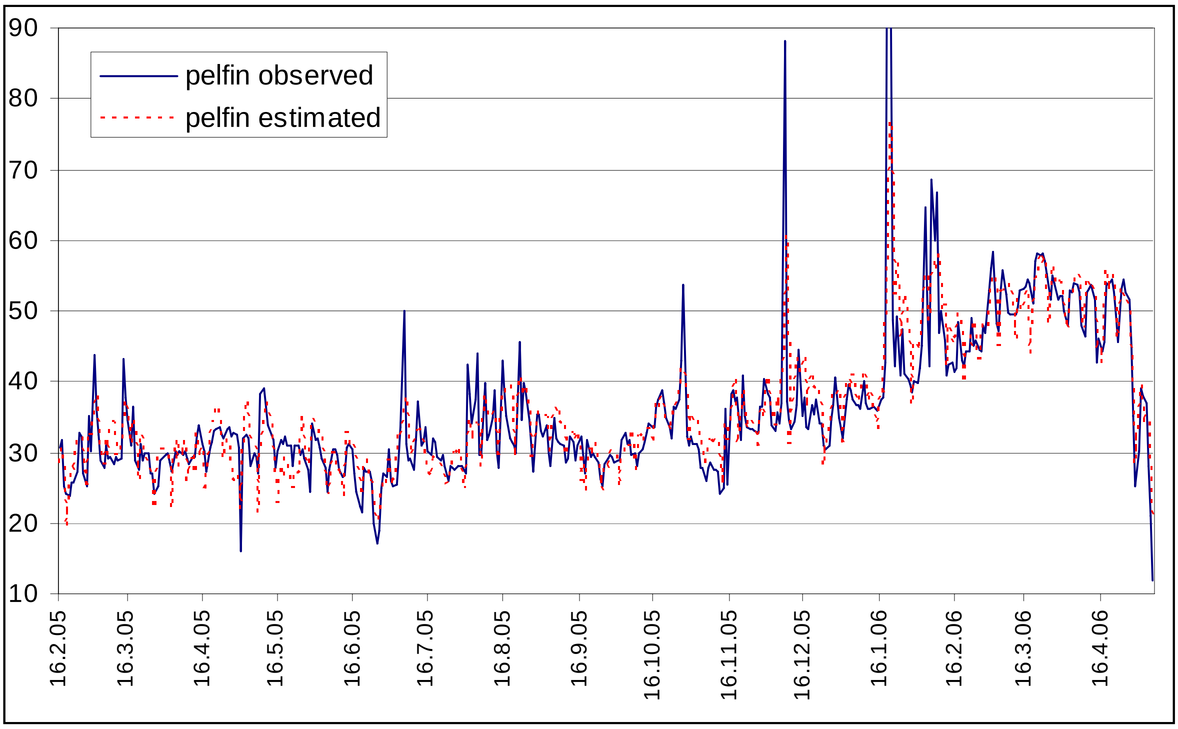

Figure 6. *Comparison of observed and estimated electricity prices (pelfin) for the Finnish NordPool area for the ARMA model (in €/MWh)*

4.3 Estimations with the AR-GARCH model

It was regarded valuable to still try another estimation method which would use levels instead of differences despite the risks of spurious correlation due to the non-stationarity of some of the series. Instead of OLS AR-GARCH was used, whereas as much as possible logarithmic transformations were used[6]. Other variables, not included in the table below, such as the coal price, have been tested, but turned out to be not statistically significant in the setting of *this* model. The utilisation rate of the transmission capacity with Russia was sometimes significant, but not in the key results presented here. Table 4 below provides an overview of the estimation results.

The estimation results are satisfactory. The error correction terms indicate that an initial shock is followed by (small) secondary adaptations. Also in this case it is obvious that the state of the power system affects the sensitivity of the spot price with respect to passing on input cost, including the price of EU ETS emission allowances.

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[6] . 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.

Table 4. *AR(1 2)-GARCH(1,1) model estimates*

```
                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

                                        Standard                 Approx
   Variable        DF      Estimate        Error    t Value    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
   HOLY             1       -0.0961       0.0431      -2.23      0.0262


                 Estimates of Autoregressive Parameters

                                          Standard
               Lag     Coefficient           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

                                        Standard                 Approx
   Variable        DF      Estimate        Error    t Value    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
   HOLY             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 no Saturday or Sunday; 0 otherwise)
HOLI	dummy for holidays that are not in a weekend (1 for holidays out-side weekends, 0 otherwise)
pelfin	Finnish NordPool area spot price (daily average)

In table 5 the prefix ‘ln’ denotes the natural logarithm and the extension ‘lag’ denotes the value of one day back.

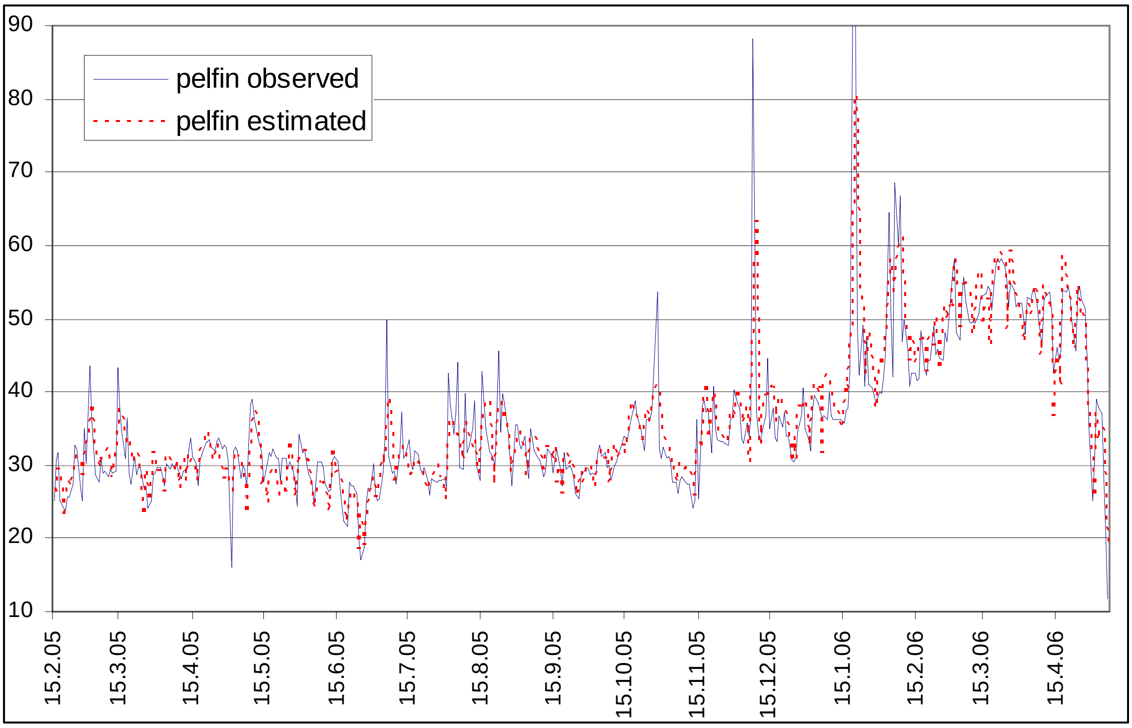

Figure 7. *Comparison of observed and estimated electricity prices (€/MWh) for the Finnish NordPool area using the AR-GARCH model*

4.4 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. The following 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;
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;
3. The entire set of results fits 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 the previous section 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 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 5. 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 earlier sections 4.1 and 4.2. 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%.

Table 5. *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 5 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 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 pass-through of 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 indicated by the estimation results, price sensitivity shows seasonal variation. From Figure 7 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 probably higher level of carbon intensity than in 2005[7]. It is however also evident that the carbon intensity stays clearly below the levels of the pre-EU ETS year 2004.

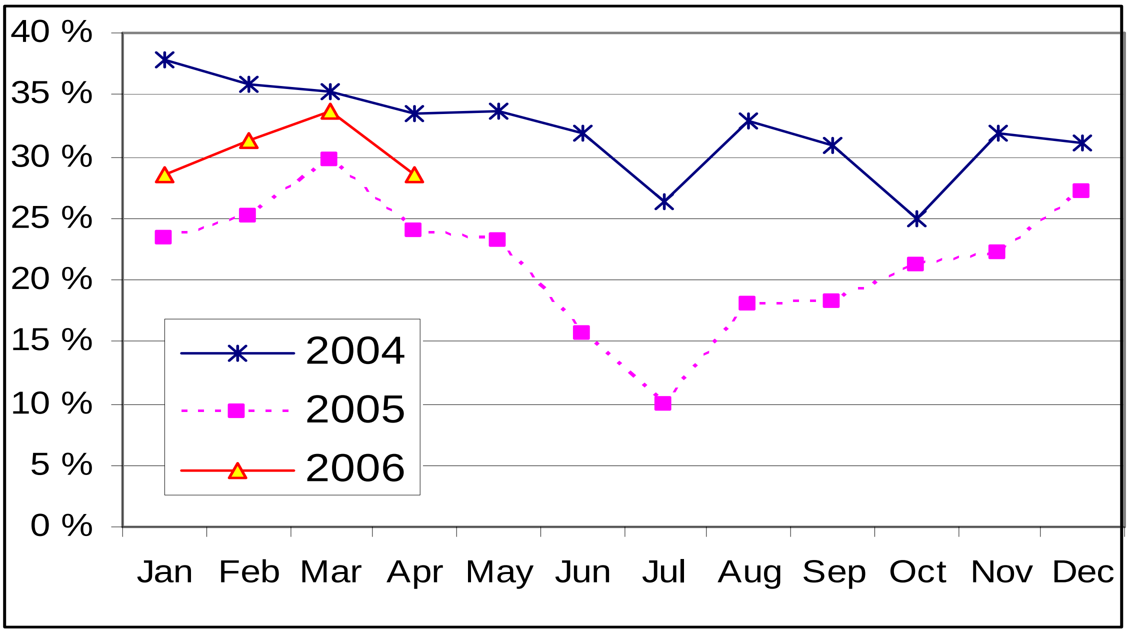

Figure 7. *Approximate shares of fossil fuel based electricity generation (incl. peat) in total domestic production in Finland (source: Adato)*

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. 7). This is in particular relevant when the

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[7] . Recent events such as the temporary shut down of various Swedish nuclear units will greatly add to higher carbon intensity in 2006.

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.

A deepening of the understanding of the interactions between power markets, EU ETS and fossil fuel markets would need a more comprehensive analysis of the possible interactions, involving spot and forward power markets, spot and forward markets for natural gas, coal prices, prices of EU ETS and expectations regarding target fulfilment for EU ETS by typical market parties such as the power sector.

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Annex 1 Backgrounds regarding the data set

For the econometric assessment data were obtained from:

- NordPool (daily and hourly observations for power prices, production, con-sumption, 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 con-tains 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 ©

variable	variable description	data type	minimum	maximum
seq_no	sequence number of observation	integer	1	861
year	year of observation	integer	2003	2006
weekno	sequence number of week in which observation is done	integer	1	52
wdayno	weekday number of observation day	integer	1	7
monthno	month sequence number	integer	1	12
mdayno	monthday sequence number of observation day	integer	1	31
date	day.month.year	date	29.12.2003	7.5.2006
cons	daily consumption of electricity in Finland	real	106984	338386
prod	daily production of electricity in Finland	real	105731	291315
prcautd	utilisation of Finnish production capacity - daily average	real	0,356	0,857
import	daily net import of electricity into Finland	real	-18471	74429
imp_rus	daily net import of electricity into Finland from Russia	real	416	35496
imp_swe	daily net import of electricity into Finland from Sweden	real	-37236	44893
imp_nor	daily net import of electricity into Finland from Norway	real	-1408	1623
imp_util	daily utilisation rate of total cross-border transmission capacity	real	-0,39	1,20
imprutil	daily utilisation rate of Russia-Finland cross-border transmission capacity	real	0,01	0,95
impsutil	daily utilisation rate of Sweden-Finland cross-border transmission capacity	real	-1,22	0,95
impnutil	daily utilisation rate of Norway-Finland cross-border transmission capacity	real	-0,59	0,68
hydrofil	filling rate of hydro power basins in whole Nordpool area on observation day	real	20,68	88,80
hydromed	median filling rate of hydro power basins in whole Nordpool area on observation day	real	33,10	87,20
hydrodev	difference between the actual and median filling rate on the observation day	real	-19,89	10,02
ETS06	daily price of EU ETS allowances for the commitment year 2006	real	7,42	30,50
ETS06X	daily price of EU ETS allowances for the commitment year 2006, incl. shadow price in 2004	real	1,00	30,50
pm_coal	monthly average price of coal imported to Finland (euro/MWh)	real	5,22	7,71
pm_gas	monthly average price of natural gas for large consumers in Finland (euro/MWh)	real	10,31	17,40
pd_coal	daily coal price (in euro/ton)	real	45,00	68,00
pd_gas	daily natural gas price	real	18,52	194,20
p_elfin	daily Finnish spot price of electricity	real	8,39	106,35
p_elsys	daily System spot price of electricity	real	16,87	58,63
cons_low	hourly consumption of electricity in Finland in low hours	real	3832	12941
prod_low	hourly production of electricity in Finland in low hours	real	3949	11596
prcautlo	utilisation of Finnish production capacity - in low hours	real	0,279	0,819
imp_low	hourly net import of electricity into Finland in low hours	real	-942	3054
impr_low	hourly net import of electricity into Finland from Russia in low hours	real	0	1508
imps_low	hourly net import of electricity into Finland from Sweden in low hours	real	-1648	1761
impn_low	hourly net import of electricity into Finland from Norway low hours	real	-54	79
imut_low	hourly utilisation rate of total cross-border transmission capacity in low hours	real	-0,50	1,24
imrutlow	hourly utilisation rate of Russia-Finland cross-border transmission capacity in low hours	real	0,00	0,97
imsutlow	hourly utilisation rate of Sweden-Finland cross-border transmission capacity in low hours	real	-1,20	0,99
imnutlow	hourly utilisation rate of Norway-Finland cross-border transmission capacity in low hours	real	-0,54	0,79
p_elfinl	hourly Finnish spot price of electricity in low hours	real	1,39	55,60
p_elsysl	hourly System spot price of electricity in low hours	real	4,54	54,92
cons_hi	hourly consumption of electricity in Finland in high hours	real	4476	14691
prod_hi	hourly production of electricity in Finland in high hours	real	4369	12597
prcauthi	utilisation of Finnish production capacity - in high hours	real	0,353	0,890
imp_hi	hourly net import of electricity into Finland in high hours	real	-862	3391
impr_hi	hourly net import of electricity into Finland from Russia in high hours	real	0	1509
imps_hi	hourly net import of electricity into Finland from Sweden in high hours	real	-1644	2015
impn_hi	hourly net import of electricity into Finland from Norway high hours	real	-60	67
imut_hi	hourly utilisation rate of total cross-border transmission capacity in high hours	real	-1,56	1,32
imruthi	hourly utilisation rate of Russia-Finland cross-border transmission capacity in high hours	real	0,00	0,97
imsuthi	hourly utilisation rate of Sweden-Finland cross-border transmission capacity in high hours	real	-2,31	1,13
imnuthi	hourly utilisation rate of Norway-Finland cross-border transmission capacity in high hours	real	-0,60	0,67
p_elfinh	hourly Finnish spot price of electricity in high hours	real	8,30	232,02
p_elsysh	hourly System spot price of electricity in high hours	real	11,23	73,64
cons_dp	hourly consumption of electricity in Finland in day plateau hours	real	4637	14220
prod_dp	hourly production of electricity in Finland in day plateau hours	real	4603	12384
prcautdp	utilisation of Finnish production capacity - in daily plateau hours	real	0,372	0,875
imp_dp	hourly net import of electricity into Finland in day plateau hours	real	-891	3423
impr_dp	hourly net import of electricity into Finland from Russia in day plateau hours	real	0	1524
imps_dp	hourly net import of electricity into Finland from Sweden in day plateau hours	real	-1697	1998
impn_dp	hourly net import of electricity into Finland from Norway day plateau hours	real	-64	83
imut_dp	hourly utilisation rate of total cross-border transmission capacity in day plateau hours	real	-0,62	1,31
imrutdp	hourly utilisation rate of Russia-Finland cross-border transmission capacity in day plateau hours	real	0,00	0,98
imsutdp	hourly utilisation rate of Sweden-Finland cross-border transmission capacity in day plateau hours	real	-1,46	1,05
imnutodp	hourly utilisation rate of Norway-Finland cross-border transmission capacity in day plateau hours	real	-0,64	0,83
p_elfind	hourly Finnish spot price of electricity in day plateau hours	real	5,95	67,99
p_elsysd	hourly System spot price of electricity in day plateau hours	real	16,64	60,80
dol_euro	exchange rate dollar-euro (dollars/euro)	real	1,17	1,36
prodcap	Finnish production capacity	real	12360	14160
temp	daily temperatures Finland weighted by spatial distribution of economy & population	real	-21,1	22,7
dev_temp	deviation from long term average temperature for that day	real	-16,7	10,5

variable	**source**	**remarks**
seq_no		
year		only last few days of 2003, week 1 in 2004 starts in 2003
weekno		
wdayno		
monthno		
mdayno		
date		
cons	Nordpool	measured in MWh
prod	Nordpool	measured in MWh
prcautd		
import	Nordpool	measured in MWh, + means import, - means export
imp_rus	Nordpool	measured in MWh, + means import, - means export
imp_swe	Nordpool	measured in MWh, + means import, - means export
imp_nor	Nordpool	measured in MWh, + means import, - means export
imp_util	Nordpool/Nodel/Vatt	+ means import flow, - export flow
imprutil	Nordpool/Nodel/Vatt	+ means import flow, - export flow
impsutil	Nordpool/Nodel/Vatt	+ means import flow, - export flow
impnutil	Nordpool/Nodel/Vatt	+ means import flow, - export flow
hydrofil	Nordpool/Nordel (2004)	interpolated from weekly data
hydromed	Nordpool/Nordel	interpolated from weekly data
hydrodev		expressed as (percent)points
ETS06	Nordpool	for non working days the most recent price is used
ETS06X	Nordpool/Vatt	for non working days the most recent price is used
pm_coal	Statistics Finland	euro/MWh (primary energy value)
pm_gas	Statistics Finland	euro/MWh (primary energy value)
pd_coal	Argus	Baltic port notation. Max. 90 dayl delivery, converted from $ to €/ton
pd_gas	Heren Energy	£/Therm
p_elfin	Nordpool	euro/MWh
p_elsys	Nordpool	euro/MWh
cons_low	Nordpool	low' is implemented as the average of hour 2 and 3
prod_low	Nordpool	low' is implemented as the average of hour 2 and 3
prcautlo		
imp_low	Nordpool	low' is implemented as the average of hour 2 and 3
impr_low	Nordpool	low' is implemented as the average of hour 2 and 3
imps_low	Nordpool	low' is implemented as the average of hour 2 and 3
impn_low	Nordpool	low' is implemented as the average of hour 2 and 3
imut_low	Nordpool	low' is implemented as the average of hour 2 and 3
imrutlow	Nordpool	low' is implemented as the average of hour 2 and 3
imsutlow	Nordpool	low' is implemented as the average of hour 2 and 3
imnutlow	Nordpool	low' is implemented as the average of hour 2 and 3
p_elfinl	Nordpool	low' is implemented as the average of hour 2 and 3
p_elsysl	Nordpool	low' is implemented as the average of hour 2 and 3
cons_hi	Nordpool	high' is implemented as the average of hours 8 and 19
prod_hi	Nordpool	high' is implemented as the average of hours 8 and 19
prcauthi		
imp_hi	Nordpool	high' is implemented as the average of hours 8 and 19
impr_hi	Nordpool	high' is implemented as the average of hours 8 and 19
imps_hi	Nordpool	high' is implemented as the average of hours 8 and 19
impn_hi	Nordpool	high' is implemented as the average of hours 8 and 19
imut_hi	Nordpool	high' is implemented as the average of hours 8 and 19
imruthi	Nordpool	high' is implemented as the average of hours 8 and 19
imsuthi	Nordpool	high' is implemented as the average of hours 8 and 19
imnuthi	Nordpool	high' is implemented as the average of hours 8 and 19
p_elfinh	Nordpool	high' is implemented as the average of hours 8 and 19
p_elsysh	Nordpool	high' is implemented as the average of hours 8 and 19
cons_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
prod_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
prcautdp		
imp_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
impr_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
imps_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
impn_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
imut_dp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
imrutdp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
imsutdp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
imnutodp	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
p_elfind	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
p_elsysd	Nordpool	daily plateau' is implemented as the average of hours 14 and 15
dol_euro	ETLA/Suomen Pankki	
prodcap	Nordel/Adato	in summer time (27-5//16-9) 1800 MW less due to switch off of DH
temp	Finnish Meteorological I	degree celsius
dev_temp	Finnish Meteorological I	degree celsius