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Anna Widerberg and Markus Wråke

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Department of Economics
School of Business, Economics and Law at University of Gothenburg
Vasagatan 1, PO Box 640, SE 405 30 Göteborg, Sweden
+46 31 786 0000, +46 31 786 1326 (fax)
www.handels.gu.se   info@handels.gu.se

The Impact of the EU Emissions Trading System on CO_2 Intensity in Electricity Generation

Anna Widerberg[1*] **and Markus Wråke**[2,1]

[1]Department of Economics, University of Gothenburg, Box 640, 405 30 Gothenburg, Sweden
[2] IVL Swedish Environmental Research Institute Ltd, Box 210 60, 100 31 Stockholm, Sweden

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Abstract

Prior to the launch of the EU Emissions Trading System (EU ETS) in 2005, the electricity sector was widely proclaimed to have more low-cost emission abatement opportunities than other sectors. If this were true, effects of the EU ETS on carbon dioxide (CO_2) emissions would likely be visible in the electricity sector. Our study looks at the effect of the price of emission allowances (EUA) on CO_2 emissions from Swedish electricity generation, using an econometric time series analysis for the period 2004–2008. We control for effects of other input prices and hydropower reservoir levels. Our results do not indicate any link between the price of EUA and the CO_2 emissions of Swedish electricity production. A number of reasons may explain this result and we conclude that other determinants of fossil fuel use in Swedish electricity generation probably diminished the effects of the EU ETS.

Key words: Emissions trading, carbon dioxide, climate change, electricity, carbon intensity

JEL Classification: C22, D21, D24, Q54

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[*] Anna Widerberg (corresponding author), Department of Economics, University of Gothenburg, Box 640, 405 30 Gothenburg, Sweden, (email) anna.widerberg@economics.gu.se, (tel) +46 31 786 13 44.

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Introduction

January 1, 2005, saw the launch of the European Union's Emissions Trading System (EU ETS)—the EU's flagship climate policy instrument and a centrepiece in its commitment to reach established greenhouse gas reduction targets. Its primary objective is to reduce emissions reductions for the least cost, over and above what would have occurred without the trading system. In this paper, we analyze to what extent the EU ETS has affected the CO_2 intensity[1] in the Swedish electricity sector with an econometric time series analysis of the period 2004–2008.

The initial allocation of emissions allowances to participants is critical when designing an emissions trading system. In the EU ETS, this allocation—constituting significant monetary value—has largely been handed out to firms at no cost. In the first and second trading periods of the EU ETS (2005–2007 and 2008–2012, respectively), each EU member state had significant discretion in how they allocated their allowances to firms, which resulted in a plethora of different allocation methodologies. One recurring feature, however, was that many member states allocated fewer allowances to the electricity sector in relation to their past emissions, compared to other industry sectors. Two arguments seem to be the principal motivations for this decision. First, because price elasticity of electricity is low and the electricity sector is not exposed to direct competition from non-European countries, electricity companies could more easily pass on additional costs to consumers without loss of output or market share. Second, which is important for this study, several member states—including Sweden—identified the electricity sector as having better opportunities to implement low-cost abatement measures (Swedish Ministry of Enterprise, Energy, and Communications 2004a, 2004b; Kolshus and Torvanger 2005; Swedish Environmental Protection Agency 2006; Jansson, 2009). This was stated both explicitly by government officials and implicitly through the design of the so-called National Allocation Plans (NAPs).

In the aggregate, demand for emissions allowances in a cap and trade system will be constant, given the cap on total emissions. If demand for allowances in certain sectors of the economy increases, this will push the price of the allowances up.[2] Because marginal abatement costs vary across firms and sectors, their emissions elasticities, in regard to change in allowance price, will be different. If the Swedish electricity sector does have lower marginal abatement costs than other sectors, it is more likely to adjust its demand for EU emissions allowances (EUA) in response to price variations in the market than sectors with higher marginal costs for emissions reductions. Hence, the EU ETS would have a visible impact on the CO_2 intensity of electricity generation, even though total emissions in the economy are constant.

Our paper contributes to the scarce empirical literature on the influence of the carbon price on emissions reductions. We hope to shed light on whether the EU ETS has encouraged any short-term abatement of emissions in the electricity sector. If no evidence of this is present, either ex ante assumptions of low-cost measures in electricity generation were incorrect or one must find other explanations for firm behaviour. To our knowledge, this is the first study of its kind. Buchner and Ellerman (2006) make an effort to untangle the relationships between fluctuating carbon prices, over-allocation of emissions allowances, and potential abatement measures at the European level. They conclude that there likely has been abatement of emissions due to the EU ETS, but find it difficult to quantify.

The remainder of the paper is structured as follows. Section 1 provides background on the Swedish electricity market. Section 2 presents the data used for the analysis. In section 3, we

[1] CO_2 intensity is defined as the emissions of CO_2 per generated unit of electricity.

[2] In the EU ETS, as discussed below, price variations also came from factors than changes in demand, notably political decisions, new information, and external developments that influence market expectations from the demand.

develop our econometric specification, detail the variables, and discuss what results can be anticipated. In section 4, we estimate the model and show the results, while section 5 concludes.

1. Swedish Electricity Generation: Dynamics and Drivers of CO_2 Intensity

The Swedish electricity system is characterised by a high degree of liberalisation and a smaller capacity for fossil fuel-based generation, compared to other European electricity markets. The Swedish system is integrated with Norway, Finland, and Denmark. Together, they form a Nordic electricity market, which has been transformed from a regulated market into its current, more liberalised form through a gradual process that started in the early 1990s. The liberalisation of the market aimed to make its capacity more efficient, increase the choices for consumers, and develop a more cost-effective energy supply. The dominant position of some utilities, especially in local markets, was an issue (and still is according to some observers), and a common Nordic electricity market would significantly reduce their dominance and guarantee stronger competition. Generation and trade of electricity are now open to competition, although the transmission networks are still regulated monopolies with national government control. Although it shows many characteristics of a competitive market, the integration, harmonisation, and expansion of this market is ongoing.

Table 1 shows the profile of electricity generation in the Nordic countries in 2007. In Sweden, coal is used in a small number of combined heat and power plants (CHP) and in some industrial boilers. Natural gas is also used in CHP and some peak-load units. Oil is mainly used in industrial boilers and in units which come on line during extreme cold spells or are reserve capacity when other plants are taken off line for maintenance (for example, when the Forsmark nuclear power plant was taken out of operation due to safety concerns in 2007).

Table 1 Electricity Production in the Nordic Electricity Market in 2007

	Denmark	Finland	Norway	Sweden
Total generation*	**37,2**	**77,8**	**137,4**	**145,1**
Total thermal power	**27,7**	**53,6**	**0,7**	**68,2**
Nuclear power	–	22,5	–	64,3
Other thermal power**	27,7	31,1	0,7	3,9
- Coal	20,3	13,6	–	0,9
- Oil	0,3	0,4	–	0,8
- Peat	0,0	7,0	–	0,1
- Natural gas	6,8	10,1	0,7	1,2
- Others***	0,3	–	–	0,9
Total renewable power	**9,6**	**24,2**	**136,7**	**76,9**
Hydro power	0,0	14,0	135	65,5
Other renewable power	9,5	10,2	1,7	11,4
- Wind power	7,2	0,2	0,9	1,4
- Biofuel	0,3	9,4	0,0	8,7
- Waste	1,6	0,6	0,8	1,3
- Geothermal power	–	–	–	0,0
Net imports	**-1,0**	**12,9**	**-10,0**	**1,3**

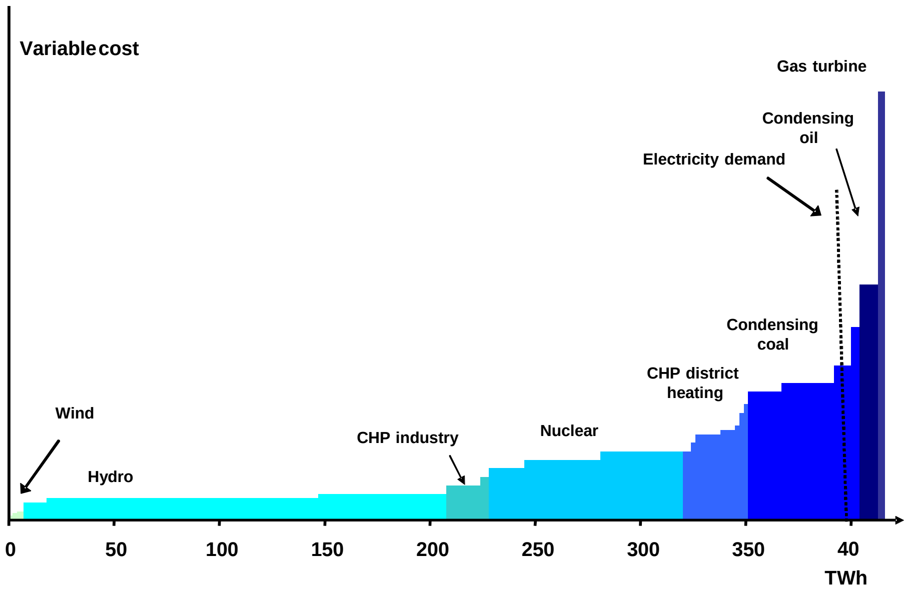
* In Norway, gross electricity production; ** fossil fuels; *** West Denmark includes refinery gas.
Source: Nordel (2007).

The dynamics of fossil fuel-based electricity in Sweden are closely tied to district heating because a large proportion of thermal power is generated by CHP units. The low fossil fuel volume also affects the dynamics of dispatch and the flexibility of the fuel mix. The demand for heat is a major determinant of CHP generation, so the impact of electricity generation on input price fluctuations may be somewhat lower, compared to simple power generation. The same can be true for electricity generation by industrial boilers, which primarily support production of other goods (such as steel or paper pulp). Thus, the price of fuels may be less important for these units than for a regular power plant. Finally, some of the most CO_2-intensive plants exist as back-up capacity for unexpected events, which may decrease the elasticity regarding input prices.

We expect our model to capture opportunities to reduce emissions that are available to firms in the short run. These include fuel switching, technical means of improving efficiency, and dispatch planning, such as modifying the merit order. Large utilities, such as Vattenfall, EON, and Fortum, have portfolios of capacity units and can thus change the internal merit order in response to market fluctuations. Smaller firms have less flexibility and altered output is sometimes the only option for dispatch planning. Furthermore, the large district heating networks in Stockholm, Göteborg, and Malmö can respond more quickly to market price changes because they have more options for altering the merit order of units than do smaller networks. New investments offer the best possibilities for switching fuels in the long term. In the short term, some plants which co-fire fossil fuels with biofuels have some flexibility.[3] In sum, fossil fuel-based generation often constitutes the marginal capacity and thereby sets the electricity price in the Nordic market. (Figure 1 shows the principal merit order of the Nordic market.) It is clear that opportunities exist for abating CO_2 emissions in the electricity sector, but the structure of the Swedish electricity sector and the existing mix of fuels and plant types restrict how quickly firms can respond to changes in input prices.

A related question is how electricity prices are affected by the price of EUA. Research on this issue has been done for the Nordic market, as well as other European electricity markets (e.g., Sijm et al. 2006, 2008; Fell 2008; Bunn and Fezzi 2007; Alberola et al. 2008; Åhman et al. 2008, and Wråke et al. 2008). Fell (2008) uses a co-integrated vector autoregressive (CVAR) analysis and reports a near full pass through of carbon costs in Nordic electricity prices. Bunn and Fezzi (2007) use similar methodology and find comparable results for the U.K. market. This supports the view that electricity firms internalise the cost of carbon into their product prices. Alberola et al. (2008) apply a single equation specification, primarily to identify structural breaks in the allowance market itself.

Figure 1 Principal Merit Order Curve in the Nordic Electricity Market



Source: Swedenergy

2. Data

Getting access to accurate and detailed data has been one of the greatest challenges for quantitative assessments of the EU ETS. We are interested in the link between EUA prices and CO_2 intensity in the Swedish electricity sector. For this purpose, we combine two unique data series to calculate weekly CO_2 emissions: weekly output of different kinds of generation capacity and monthly data on fuel consumption for each type of plant. By dividing total emissions by total output, we can calculate the CO_2 intensity for each week. Although this approach is not ideal, it still permits a relatively detailed analysis of short-term responses in firm behaviour to variations in the price of allowances.

[3] (For a detailed bottom-up inventory of CO_2 abatement opportunities in the Swedish energy sector, see Särnholm 2005).

An implicit assumption in the construction of the data set is that the proportion of fossil fuels used in each plant type is constant within a month. This puts certain restrictions on what types of measures our analysis can capture and in what resolution. We cannot detect how much fuel switching occurs weekly by specific plant type, only their monthly levels. However, weekly variations in emissions for each plant type reflect variations in output, which means that we can capture variations in how the portfolio of plants is used on a weekly basis.

Our data covers the period January 2, 2004–August 29, 2008, i.e., from one year before the launch of the first trading period through three-quarters of the first year of the second trading period. Inputs relevant to Swedish electricity generation include prices of EUA, natural gas, coal, oil, electricity, and biofuels. (The time series for these variables are presented in figure 2.) As relative prices are most important for fuel choice, we normalise all prices against the price of electricity. We also include a proxy for the value of water in the hydropower reservoirs. Because nuclear power plants have limited flexibility to respond to short-term changes, we feel it unnecessary to include the price of uranium in the analysis.

CO_2 intensity has a clear seasonal pattern. Total demand for electricity increases during the colder months, and more fossil fuels are used. Also noteworthy is the spike in electricity prices during the second half of 2006. This was primarily driven by the dry conditions that year, which reduced the volume of water available as hydropower, as seen in figure 2 in the panel showing reservoir level.

EUA price (€/ton emitted) is the weekly average of European prices.[4] The natural gas price[5] (€/Btu) is the weekly average of day-ahead prices from the Zeebrugge hub.[6] The coal price[7] (€/ton) used is the weekly average of spot prices for coal delivered to the Amsterdam/Rotterdam/Antwerp region. The oil price (€/barrel)[8] used is the weekly average of the daily prices of Brent North Sea oil. The biofuel prices[9] (€/MWh) are based on quarterly data for Sweden, interpolated to weekly resolution. As a proxy for the value of the water available for hydropower generation, we use the deviation from average levels in the Nordic hydropower reservoirs for each week to measure the relative scarcity of water:[10]

$$(level)_t = (percent\_of\_capacity)_t - \overline{(percent\_of\_capacity)_t}$$

where $(percent\_of\_capacity)_t$ is the percent of the Nordic region's reservoir capacity that is filled for week *t* and $\overline{(percent\_of\_capacity)_t}$ is the historical median of percent of capacity for week *t*. Electricity prices (€/MWh) used are the average day-ahead Elspot hourly system prices for weekdays.[11] Figure 2 displays plots of all variables, and table 2 gives descriptive statistics of the variables.

[4] We use the weighted spot/over the counter (OTC) price as reported by Point Carbon.

[5] Primary source, Reuters

[6] Prices for natural gas, oil, and biofuels were converted from British pounds, American dollars, and Swedish kronor to euros, using daily exchange rates.

[7] Primary source, Reuters

[8] Ibid.

[9] Primary source, the Swedish Energy Agency

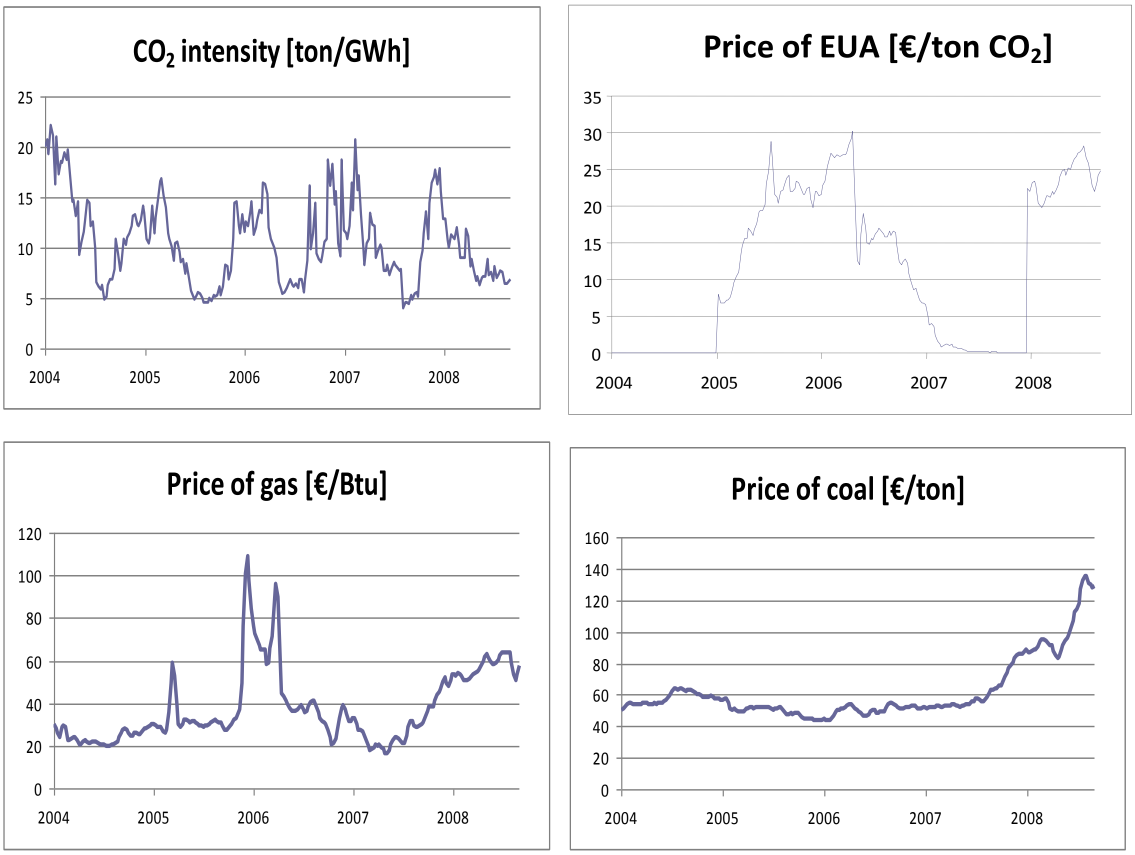
[10] Primary source, Nordpool.

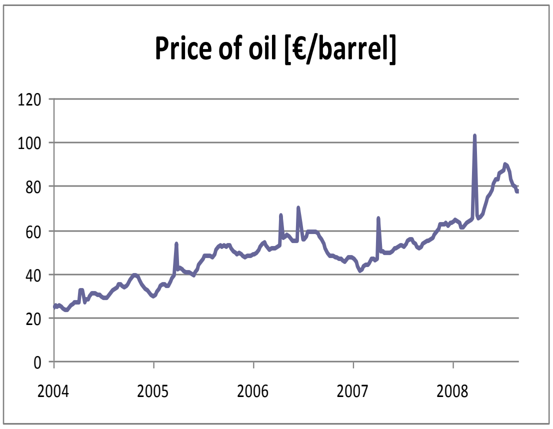
[11] We use only weekdays since demand patterns shift during weekends when households are more important. Our focus here is on the industry actors in the market.

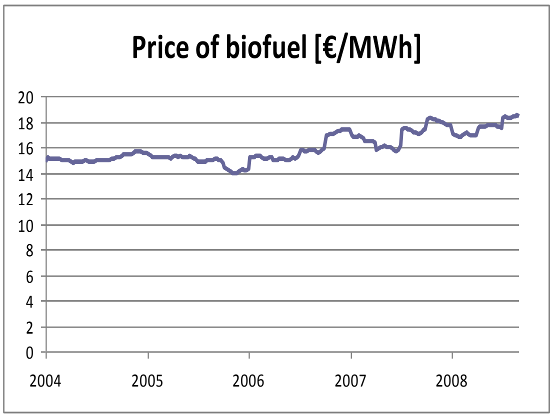
Table 2 Descriptive Statistics of the Variables

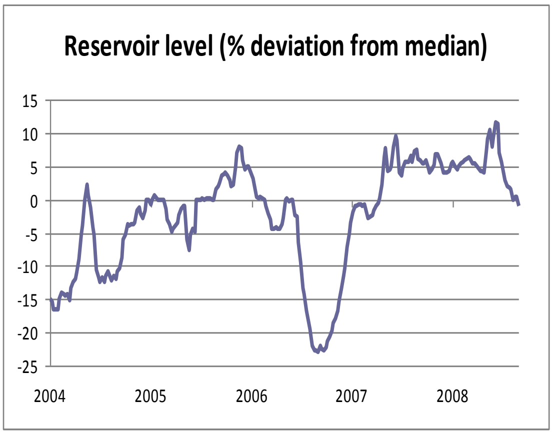
	Obs.	Mean	Std. dev.	Min.	Max.
CO_2 intensity	244	10,53	4,13	4,03	22,17
Gas price	244	37,67	17,31	16,21	109,24
Coal price	244	61,73	19,64	43,59	135,54
Oil price	244	49,30	14,88	23,32	102,68
Biofuel price	244	15,96	1,18	13,96	18,47
EUA price	244	11,38	10,58	0,00	30,14
Reservoir level	244	-2,24	8,10	-23,00	11,48

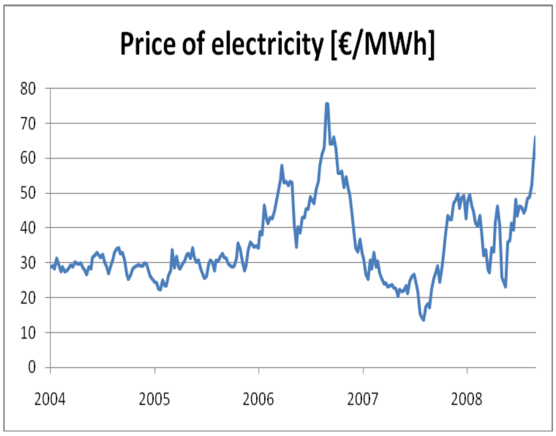
Figure 2 Plots of the Data











3. Econometric Specification and Anticipated Results

We apply an autoregressive distributed lag (ADL) model with the general specification:

$$Y_t = \alpha + \sum_{i=1}^{k-1} \left[\beta_i Y_{t-i}\right] + \sum_{i=0}^{k-1} \sum_{j=1}^{m} \left[\gamma_{j,i} Z_{j,(t-i)}\right] + \varepsilon_t \ ,$$

where α is the intercept; Y_t is the CO_2-intensity in week t; Z_t are the m exogenous variables in week t; k is the number of time lags chosen for each variable; β_i, $\gamma_{i,j}$ are estimated coefficients; and ε_t is the error term.

The robustness of the model and the quality of subsequent results were verified through preliminary and diagnostic tests as described below and in appendix A. In order to obtain estimates that are easy to interpret, we use the natural logarithm of the relative input prices. This also has the advantage that the variables are stationary, which simplifies the analysis. A common alternative, when variables are non-stationary in levels, is to use the first differences. We applied such a specification, but opted against it because the estimated coefficients are harder to interpret and did not make sense economically. Results are available on request.

We chose CO_2 intensity as the dependent variable in the model. Another possible approach would be to analyse CO_2 emissions and control for electricity generation. This yields very similar results[12] to those presented below, but we detected some heteroskedasticity in this model specification.

The dramatic variations in the allowance prices have featured prominently in discussions about the EU ETS. In particular, the April 2006 price crash, the October 2006 price slide, and the sharp increase in prices in 2008 (the start of the second trading period) attracted significant attention both in the public debate and the academic literature.[13] Our dependent variable does not display any structural breaks, so we have no concerns about our approach in this regard. However, in order to ensure that the breaks in the EUA price do not influence the behaviour of Swedish electricity firms, we conducted analyses where we considered this possibility without finding any evidence. (See appendix B for a discussion and results.)

The seasonality of CO_2 intensity reflects the variable Swedish climate, not surprisingly, and needs to be included in the analysis. One option is to include seasonal dummies in the model specification, but (as discussed below) the results of our regression strongly indicate that seasonality is captured with the model specification we apply without them. Based on previous knowledge of the characteristics of the electricity system, we anticipate certain results:

- **Past CO_2 intensity.** Since we expect the system to display some degree of inertia, it is reasonable to believe that past CO_2 intensity will have a positive but decreasing influence on present intensity. That is, we anticipate a positive sign of the estimated parameter.
- **Price of natural gas.** The effect of a change in gas price depends on the substitute for natural gas in the system. As the merit order curve in figure 1 indicates oil or coal-fired plants are likely substitutes in the short run and, hence, we anticipate that an increase in the price of natural gas will cause an increase in CO_2 intensity (positive sign).
- **Price of coal.** Coal is the most CO_2-intensive fuel used in the electricity system (barring some process gases produced by the steel industry), so we expect that an increase in coal prices will prompt a fall in CO_2 intensity (negative sign).
- **Price of oil.** The effect of oil price change is more ambiguous than for natural gas and coal since it is less clear what the substituted fuel would be. If it is coal, an increase in oil price would spur an increase in emissions, but if the substitute is gas or biofuels, emissions would fall. Consequently, it is difficult to anticipate the sign.
- **Price of EUA.** EUA prices add a cost that is directly linked to emissions of CO_2, so we anticipate any effect on CO_2-intensity will be negative.
- **Price of biofuel.** As biofuels are regarded as having zero emissions, any shift away from biofuels would have a neutral or positive effect on emissions. Thus, we expect a positive estimated coefficient for the price of biofuel.
- **Reservoir level.** This variable was constructed to measure the value of water in the hydropower reservoirs. If the reservoir levels exceed the median for a particular week, we take that as a proxy for a decrease in the value of the water. Thus, we expect a negative sign on the estimated parameter for the level variable, indicating that as reservoir levels increase, more hydropower is used in the system, which prompts a fall in CO_2 intensity.
- **Variables controlling for institutional changes.** If electricity companies had realised that there was a surplus of allowances as early as April 2006 and consequently changed their behaviour (even though the market as a whole did not), we would expect a

[12] Results available on request

[13] See, for instance, Alberola et al. (2008) for a thorough discussion of structural breaks in the EUA price.

negative sign on the April 2006 dummy estimate and a positive sign on the December 2007 dummy estimate.

4. Results and Discussion

The significant results of the regression are shown in table 3. In the regression, we include three lags of each variable. The number of lags was chosen through a step-by-step reduction from six lags until all lags were significant for at least one variable.

Oil price, EUA price, and reservoir level, all with three lags, are included in the regression, but the estimates are not significant. (The full table of results can be found in appendix A.) We find CO_2 intensity to be significant in the first lag with a positive sign. The following lags are not significant, but show drastically decreasing coefficients, as anticipated.

The price of gas is significant, in both the unlagged price and all lags. For gas and coal, the estimated lags change between positive and negative signs. This is not surprising, as it shows that a spike in input prices at time *t* should affect the CO_2 intensity in that period, and then fade away. The CO_2 intensity returns to its average level, hence the opposite sign of t-1 estimates. In order to understand the total effect, long-term estimates[14] of the variables were calculated in table 4. Here, all significant estimates have the anticipated signs.

[14] The long-term solution is calculated as the sum of the coefficients for the unlagged and lagged independent variable divided by (1 minus the coefficients of the lagged dependent variable).

Table 3 Reduced Results from the Regression Analysis and Diagnostic Tests

CO_2 intensity	Coeff.		Std. err.
CO_2 intensity lag 1	0,796	***	0,068
Gas price (relative)	0,677	***	0,184
Gas price (relative) lag1	-1,244	***	0,380
Gas price (relative) lag2	0,928	**	0,381
Gas price (relative) lag3	-0,338	*	0,183
Coal price (relative)	-1,382	***	0,257
Coal price (relative) lag1	2,185	***	0,453
Coal price (relative) lag2	-1,446	***	0,481
Coal price (relative) lag3	0,634	**	0,273
Constant	0,308	**	0,096
Diagnostic Tests			
R-square		0.86	
Adjusted R-square		0.84	
F-stat, p-value		0.00	
Durbin Watson, h-value		0.33	
Breusch-Godfrey, p-value		0.31	
Breusch-Pagan, p-value		0.88	

*** significant at 1% level, ** significant at 5% level, and * significant at 10% level. Other included variables are oil price, EUA price, and reservoir level.

Table 4 Long-Term Estimates of the Variables

	Long-term estimate
Gas price (relative)	0,20
Coal price (relative)	-0,081
EUA price (relative)	0,14

Even though the estimates of the EUA price were not significant, we chose to present the long-term estimate since this is the most important variable in the analysis. We found no other significant estimates.

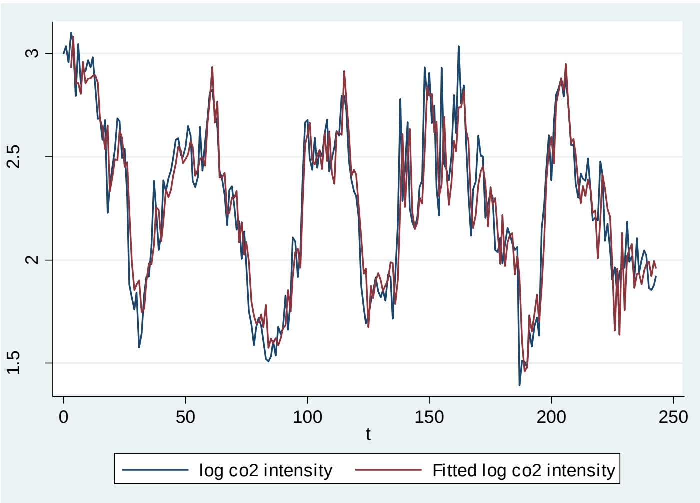
To our knowledge, there is no data on biofuel prices with better resolution than ours. Still, because prices are stable (see figure 2), we have doubts about how much information the data series contains; thus, in the final model the variable is excluded from the regression.[15]

The robustness of our model we verified through diagnostic statistics (see table 3). We calculated the Durbin-Watson h-value and the Breusch-Godfrey test statistic to detect autocorrelation, and the Breusch-Pagan tests for Heteroskedasticity, and test statistics showed no indication of either.[16] To ensure that the insignificant variables do not jointly influence the CO_2 intensity, we performed F-tests on the sum of the coefficients for these variables, without finding significance.

Because we began the analysis one year before the launch of the EU ETS, the first year of the study had no prices for allowances. In order to keep this year in the analysis, we set the logarithm of the relative EUA price to zero for this period. We also ran regressions with two different low prices for allowances, 0.01 €/ton and 0.0001 €/ton, for this period. To ensure robustness, we also ran regressions with 2004 omitted from the analysis altogether. In all cases, results were similar to those presented here.[17] As mentioned previously, we further tested model specifications with the variables in first differences and with CO_2 emissions as our dependent variable in lieu of CO_2 intensity.

Figure 3 shows observed values of CO_2 intensity along with model predictions for CO_2 intensity. The fit of the model indicates that the specification is able to capture most variations, including the seasonality in CO_2 intensity.

Figure 3 Observed Values of the Dependent Variable (blue line) and Predicted Values from Our Model Specification (red line)



[15] When the price of biofuel is included, the estimated coefficient is insignificant.

[16] Additional plots of the data, such as the residuals versus the fitted value of the CO2-intensity, pp-plot, and qq-plot were studied. All showed the same, with no evidence of autocorrelation or heteroskedasticity.

[17] Results available on request.

Our results do not indicate any link between the price of EUA and the CO_2 intensity of Swedish electricity production in the period 2004–2008. We see a number of potential explanations for our findings:

- **Other drivers for CO_2 emissions, stronger than the price of carbon, are hiding or diminishing the effect of the EU ETS.** The generation in the fossil-fuel intense units, such as CHP and industrial boilers, can also be driven by special circumstances (accidents in other plants, unplanned maintenance), but it can also include heat demand.
- **The price of carbon, so far, with the EU ETS has been too low to induce any significant emission reductions.** This argument carries some weight, particularly because the price of EUA approached zero toward the end of the first trading period. However, at any point in time, a positive price of EUA creates incentive to abate emissions.
- **Sectors other than electricity have implemented emission reduction measures.** This is certainly possible. However, it means that the Swedish government was wrong in its assumption before the launch of the EU ETS that easy, low-cost opportunities for emissions reductions were more prevalent in the electricity sector than in other sectors.
- **Emission reductions were made in other member states.** This is also possible, but if it were the only explanation, it would mean that firms in Sweden were the only buyers in the EU ETS.[18]
- **The response time of abatement measures is longer than what our model can capture.** New, innovative abatement measures may require lead times of several years to become accepted, active, or built. However, a number of existing abatement measures could be introduced more quickly, such as fuel switching, efficiency improvements, and dispatch planning, until new measures replace old plants with new and more efficient generation capacity.
- **Firms are still learning to incorporate the cost of carbon emission into their decisions and thus did not respond fully.** This could help explain why it is difficult to link a relatively high price of EUA to abatement measures in a single sector. However, as the electricity sector is perhaps the best informed of all sectors participating in the EU ETS this argument seems unlikely.
- **Firms were expecting the price of EUA to reach zero at an early stage and thus had no incentive to implement abatement measures.** This reasoning does not convey why the price was positive for most of the trading period. Without speculating about an inefficient market for EUA—in which some agents may have supported the price using market power to gain economic benefits—this is difficult to explain. Ironically, those who put forward this argument often point to the electricity sector, claiming that many firms reaped substantial windfall profits from the higher electricity prices resulting from the EU ETS. We would also expect our model to capture this effect through the variables allowing for institutional changes to affect the results.
- **The response of CO_2 emissions to prices in EUA is asymmetric.** This argument is relevant for abatement measures where a reversal does not decrease operating costs. An example would be efficiency improvements; it would not make sense for a firm to reduce efficiency even if the price of EUA dropped below the level which triggered the improvement in the first place. However, for other measures, such as fuel switching, this explanation seems less likely to hold.

[18] Although each member state, as well as the EU Commission, collects data on market transactions, this data is not public and a deeper analysis of this issue has not been possible.

5. Conclusions

Given that the electricity sector was generally thought to hold many abatement opportunities and given that the objective of the EU ETS is to lower CO_2 intensity in the economy in general, the findings may be disturbing. However, even though our results do not indicate a significant impact of the EU ETS on emissions from Swedish electricity generation in the short run, it is difficult to see how a positive price of EU, in general and over time, would *not* lead to any abatement of carbon emissions over and above those in a scenario without a price on carbon. If, as previous research indicates, firms incorporate the opportunity cost of carbon emissions into their operating and investment decisions, we would expect to see emission reductions measures—which would not have been implemented if there was no cost of emitting carbon. Hence, we believe that the absence of a significant impact of EUA prices on CO_2 intensity primarily hinges on the structure and characteristics of Swedish electricity generation.

We draw two main conclusions. First, it seems unlikely that the EU ETS has generated any significant reductions of CO_2 emissions in Swedish electricity generation. Second, it seems unlikely that there are significant volumes of low-cost CO_2 abatement measures with short response times in the Swedish electricity sector. In order to better understand the long-term impacts of the EU ETS on CO_2 intensity, one needs to complement the analysis with studies that have stronger emphasis on investment planning.

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Appendix A Full Regression and Preliminary Tests

Results of the Regression Analysis

Table A1 Full Results from the Regression Analysis and Diagnostic Tests

CO_2 intensity	Coefficient		Std. error
CO_2 intensity lag 1	0,796	***	0,068
CO_2 intensity lag 2	0,036		0,084
CO_2 intensity lag 3	0,051		0,067
Gas price (relative)	0,677	***	0,184
Gas price (relative) lag1	-1,244	***	0,380
Gas price (relative) lag2	0,928	**	0,381
Gas price (relative) lag3	-0,338	*	0,183
Coal price (relative)	-1,382	***	0,257
Coal price (relative) lag1	2,185	***	0,453
Coal price (relative) lag2	-1,446	***	0,481
Coal price (relative) lag3	0,634	**	0,273
Oil price (relative)	0,030		0,160
Oil price (relative) lag1	-0,119		0,191
Oil price (relative) lag2	0,071		0,191
Oil price (relative) lag3	-0,160		0,157
EUA price (relative)	-0,027		0,024
EUA price (relative) lag1	0,002		0,033
EUA price (relative) lag2	-0,003		0,033
EUA price (relative) lag3	0,012		0,023
Reservoir level	0,003		0,009
Reservoir level lag1	0,001		0,014
Reservoir level lag2	-0,001		0,014
Reservoir level lag3	-0,001		0,009
Constant	0,308	**	0,096
Diagnostic tests			
R-square		0.86	
Adjusted R-square		0.84	
F-stat, p-value		0.00	
Durbin Watson, h-value		0.33	
Breusch-Godfrey, p-value		0.31	
Breusch-Pagan, p-value		0.88	

*** significant at 1% level, ** significant at 5% level, and * significant at 10% level.

Stationarity

A visual inspection of the data in figure 2 in the text indicates potential non-stationarity in some the variables. To formally test this, we performed the Augmented Dickey-Fuller (ADF) test on all variables (table A2). We cannot reject the null of a unit root (and thus non-stationarity) for any variables except CO_2 intensity and reservoir level. In order to obtain stationary variables, we transformed the price variables into relative prices with the price of electricity as base, and then took the natural logarithm of the relative prices. Relative prices to some extent also capture the magnitude and importance of each input price in relation to the price of the output (electricity). The series are presented in figure A1 and the test statistics from the ADF test for the transformed variables are presented in table A2.

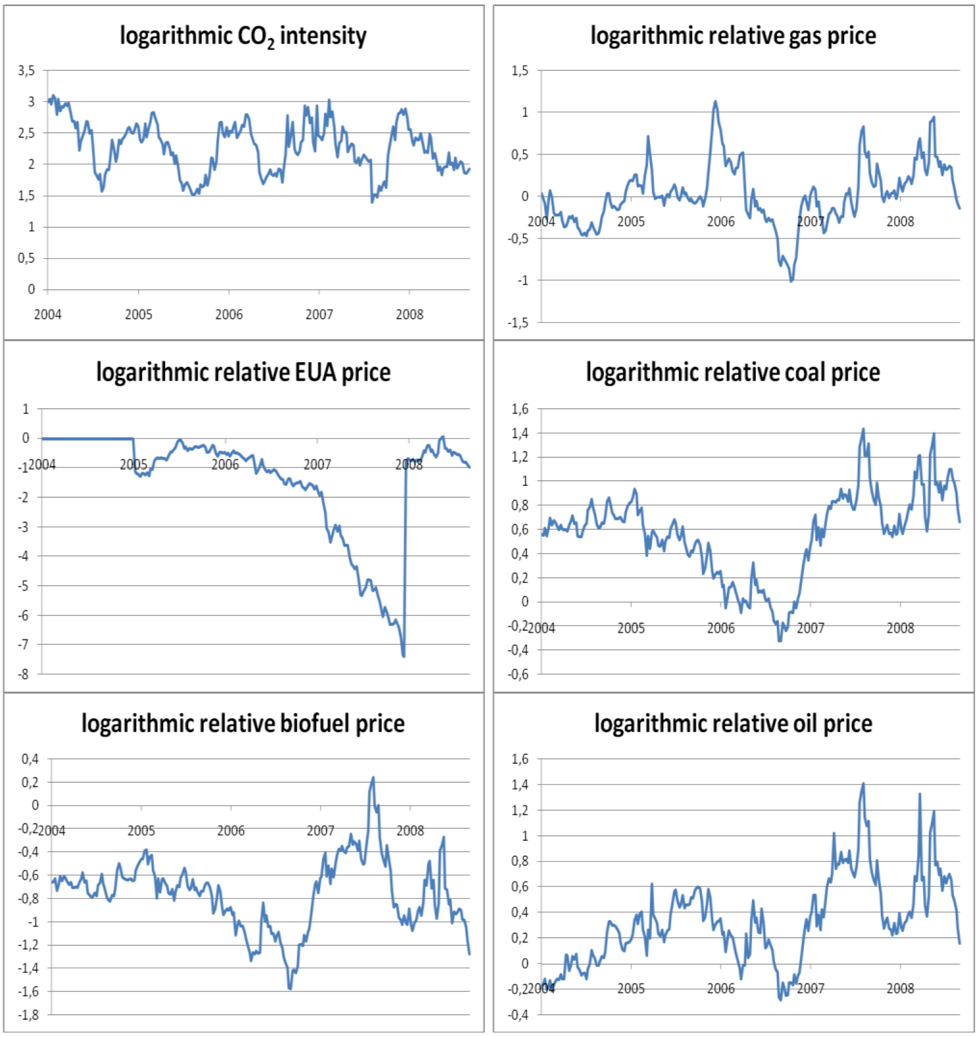
Table A2 Test Statistics for Augmented Dickey-Fuller Test with Drift, 3 Lags

CO_2 intensity	Gas price	Coal price	Oil price	Biofuel price	EUA price	Reservoir level
3,99***	-2.23	1.11	-1.03	-0.78	-1.49	-2.62*

Log CO_2 intensity	Log gas price (rel)	Log coal price (rel)	Log oil price (rel)	Log biofuel price (rel)	Log EUA price (rel)	Reservoir level
-3,58***	-2,96***	-1,91*	-2,79***	-2,27***	-1,87*	-2,65***

*** significant at 1% level, ** significant at 5% level, and * significant at 10% level. Critical values applied are -1,29 for 10%, -2,65 for 5% and -2,34 for 1%.

Figure A1 Plots of the Transformed Variables



Multicollinearity

Multicollinearity is a common cause of concern in regression modelling. A simple first step to assess the risk of multicollinearity is to check the cross correlations between the variables. These are shown in table A3.

Table A3 Correlation Coefficients

	Log CO_2 intensity	Log gas price (rel)	Log coal price (rel)	Log oil price (rel)	Log biofuel price (rel)	Log EUA price (rel)	Reservoir level
Log CO_2 intensity	1,00						
Log gas price (rel)	-0,08	1,00					
Log coal price (rel)	-0,19*	0,40*	1,00				
Log oil price (rel)	-0,49*	**0,56***	**0,67***	1,00			
Log biofuel price (rel)	-0,15*	0,31*	**0,81***	**0,64***	1,00		
Log EUA price (rel)	0,03	-0,01	-0,21*	-0,41*	-0,29*	1,00	
Reservoir level	-0,25*	**0,69***	**0,56***	**0,77***	0,44*	-0,31*	1,00

Moderate to high correlations exist between some variables (in bold in table A3). The high correlation between the biofuel price and coal and oil prices is unexpected, but could come from the construction of the variable. Quarterly prices of biofuels are fairly stable, and a large proportion of the fluctuation observed in our variable is in fact related to the SEK-Euro exchange rate. The fluctuation in the series may, therefore, be related to the general state of the economy, which in turn may be correlated with the price of coal and oil. The reservoir level shows high correlation with the prices of gas, coal and oil. We see no apparent theoretical underpinning for this correlation.

Table A4 Results of Variance Inflation Test

	Log gas price (rel)	Log coal price (rel)	Log oil price (rel)	Log biofuel price (rel)	Log EUA price (rel)	Reservoir level	Degree day	Log Nuclear gener.
VIF	2,78	3,68	5,76	3,93	1,64	4,06	2,67	2,43

To further explore whether the presence of multicollinearity could be problematic, we performed a Variance Inflation Factor (VIF) test. The results are presented in table A4. As a rule of thumb, if VIF exceeds 10, a variable can be suspected of high collinearity with some other variable.[19]

The conclusion from these procedures is that multicollinearity does not appear to be a problem for the analysis.

[19] For a discussion, see Greene (2003).

Appendix B. Structural and Institutional Changes

Assessments of the NAPs by Zetterberg et al. (2004) and Gilbert, Bode, and Phylipsen (2004), before the EU ETS was started, indicated that installations covered by the EU ETS were given more allowances than what their emissions had been historically. They also received more allowances than warranted, if each sector of the economy were to carry an equal burden in relation to the EU Kyoto target. This led many to criticise the system for not being stringent enough even before it was launched.

Nevertheless, the first year of trading saw prices of EUAs, which were higher than many observers had expected, peaking at over 30 €/ton early in 2006 (figure 2). However, the price variations were significant and during 2007 prices fell to near zero levels. Most observers now agree that there was, in fact, an over-allocation of emissions allowances which contributed to a decline in prices. This led to speculations whether the EU ETS has reached its primary goal of reducing carbon emissions. When the second trading period was launched in January 2008, prices increased again, indicating expectations of a shorter market for allowances.

When studying the plot in figure 2 in the text, four sudden changes in the EUA price series are apparent: January 2005, April 2006, mid-autumn 2006, and December 2007. The first price increase marks the launch of the EU ETS, before which there was no price on CO_2 emissions. The sudden drop in prices in April 2006 can be directly related to the release of data of verified emissions for 2005, which indicated an over-allocation of emissions allowances. The October 2006 price slide can be linked to statements by the EU Commission, which pointed to a more stringent allocation in the second trading period starting in 2008. This may have been interpreted as another indication that there was a surplus of allowances in the first trading period, prompting a further decline in prices. The final dramatic price change, in December 2007, indicates the start of the second trading period.[20]

Some observers were surprised that the price of EUA did not immediately drop to zero after the verified 2005 emissions became available in April 2006. Instead, the prices were relatively stable for a period, before they gradually fell towards zero in 2007. This seems to indicate that the market as a whole did not realise that there was a surplus of allowances until mid-2007. However, it has been suggested that electricity firms—given their long experience from trading in markets similar to the EU ETS, the importance of the EUA price to their operations, and their active role in the debate on the EU ETS—may have been in a better position to analyze the EUA market than other industry sectors. Furthermore, they did have an incentive to keep allowance prices positive, as this earned them profits on the large volumes of non-emitting power generation, such as nuclear and hydro.

This could suggest controlling for a change in behaviour of Swedish electricity firms at the times of the breaks in EUA prices, even though our dependent variable, CO_2 intensity, does not show corresponding structural breaks. For example, it is possible that seasonal variations in electricity generation are masking effects of institutional changes. Therefore, we also ran regressions with dummies aimed at controlling for these changes in the model specification.

In order to formally identify the break points in the EUA price series, we ran the test developed by Bai and Perron (1998), allowing for four potential breakpoints. The test indicates a first break in the first week of March 2005, a second break in the third week of April 2006, a third break in the second week of January 2007 and a fourth break in the last week of 2007.

If we instead allow for three structural breaks in the Bai and Perron test, the break in October 2006 appears instead of the January 2007 break. Due to the uncertainty in the October

[20] As our price series are for contracts with December delivery, the increase in prices occurred in December 2007, rather than January 2008.

2006 break, we limited our model to include the April 2006 price drop and the December 2007 price increase.

A comparison with previous research shows that Fell (2008), Bunn and Fezzi (2007), and Alberola et al. (2008) included the April 2006 break. Fell also included dummies for the start of the second trading period, while Alberola et al. included the break in October 2006 in their analysis. Alberola et al. used a slightly different approach and first identified a "compliance break period" between April 26 and June 23, 2006, and excluded this period from the data. They then identified a second break in October 2006 and explained it in a similar way as we do.

However, regression results do not show any significance in either the April 06 dummy or the December 2007 dummy.[21] Thus, we find no support for the suggestion that electricity firms altered their way of incorporating the carbon price after these events.

[21] Results available on request.