2. Executive Summary

With the introduction of CO_2 emission constraints on power generators in the European Union, climate policy is starting to have notable effects on energy markets. This paper sheds light on the links between CO_2 prices, electricity prices, and electricity costs to industry. It is based on a series of interviews with industrial and electricity stakeholders, as well as a rich literature seeking to estimate the exact effect of CO_2 prices on electricity prices. Beyond a theoretical look at the CO_2 and electricity pricing interactions, it describes how electricity markets are organised at present, how industrial users purchase their electricity and how such practice may affect the CO_2 price signal. The variety of situations presented here should be of interest of other countries and regions as they consider how to best reduce emissions from power generation, the single largest contributor to energy-related CO_2 emissions in OECD countries.

Emissions Trading Systems in Europe and Elsewhere

The European Union introduced the EU emissions trading scheme (EU ETS) on January 1, 2005, which sets caps for the CO2 emissions of some 11,500 plants across the EU-25. Installations have the flexibility to increase emissions above their caps provided that they acquire emission allowances to cover emissions above. Installations with emissions below caps are allowed to sell unused allowances. The EU ETS has sparked a vibrant EU allowances (EUA) market, with transactions totalling EUR 14.6 billion in 2006 (Point Carbon, 2007), and created a visible price of CO_2. This price is now another cost component for covered installations, including power generators, by far the largest emitter in the scheme. Other local or regional governments are at various stages of discussion or implementation of emission trading systems (Ellis and Tirpak, 2006).

CO_2 Prices in Electricity Prices: a Condition for Cost-Effective CO_2 Reductions

Economic theory explains why, under a cap-and-trade system, the price of emissions ought to be treated as a marginal cost. As a generator holds allowances, the production of CO_2-emitting electricity competes with the possibility to sell the unused allowances. This so-called opportunity cost of CO_2 allowances, equal to the CO_2 market price, is therefore incorporated in operators' decisions to generate electricity. So far, EUA have been distributed for free to installations. Whether or not the full opportunity cost of such free allowances finds its way to end-user electricity prices depends on several elements including: contractual agreements between suppliers and end-users, regulatory frameworks, but also the elasticity of demand and the rules used by governments to allocate EU allowances. The possibility that future allowances be distributed on the basis of current emissions creates an incentive not to pass through the full opportunity cost, as this may result in lower demand, lower emission and a lower "rent" allocation. The economic rationale behind a "cap-and-trade" system is nonetheless that the price of emissions should be reflected in final prices, to encourage lower consumption, and to encourage cleaner generation through higher expected revenues. Only then can such a scheme trigger an overall cost-effective response to the emission constraint.

If any evidence is needed of the CO_2 pass-through into electricity prices, it was provided by the abrupt fall of the CO_2 price in May 2006, as market players were made aware of the excess quantity of EU allowances for the year 2005. The fall by EUR 10/tCO_2 was immediately followed by a drop in wholesale electricity prices of EUR 5-10/MWh (Point Carbon).[1] This electricity price adjustment can be directly attributable to the CO_2 price fall, itself not connected to other energy market movements that could also affect electricity prices.

There is no universal answer on how the EU ETS has affected electricity prices. First, there is no single EU electricity market, but several market and regulatory frameworks across the EU (EASAC, 2006). Second, many other factors affect generation prices such as high natural gas prices in 2005 or the potential use of market power by electric utilities.[2] Third, as no data can be gathered on the bidding strategies, and the marginal supplier to the market, determining the precise level of pass-through of CO_2 prices in electricity prices is not possible. Without adequate information on the price-setting technologies across markets, countries and load periods, and without explaining away other volatility factors in the price, empirical estimates of pass through rates remain tentative. Several studies did provide estimates: Sijm et al. (2006) find rates ranging from 39 to 73 percent for Germany and the Netherlands for the period January-July 2005 and from 60 to 80 percent for the same countries between January-December 2005.

From Electricity Generation Prices to Industrial Electricity Costs

Considering that end-user prices are a mix of various market prices and differ between end-user categories (e.g., energy-intensive users, small enterprises, residential, etc.), the impact of CO_2 on end-user electricity prices is even less well known than the impact on generation prices. How does the electricity cost faced by industrial energy users relate to the prices observed on electricity markets (whether they are organised through an exchange or not)? Obviously, the relationship hinges on industrials' power purchasing strategies. As a result, changes in electricity costs for energy-intensive industries cannot be estimated from day-ahead or forward electricity prices variations – although supply contracts are sometimes indexed to exchange prices.[3] For example, some industrial electricity users are still bound by long-term contracts. Others may have adopted purchasing strategies based on forward electricity prices, thus limiting their exposure to both electricity and CO_2 allowance price volatility.[4]

In Europe, industry has access to various electricity pricing mechanisms, depending on their country or region of operation. Here are the main broad categories identified:

- *Market prices set by the marginal generator or bidder.*

In Scandinavia**,** hourly prices formed on the Nord Pool exchange, representing the hourly marginal cost of the marginal generation plant, are the dominant element of electricity supply contracts.

[1] EurActiv (2006): Crashing carbon prices puts EU climate policy to the test, May. http://www.euractiv.com/en/sustainability/crashing-carbon-prices-puts-eu-climate-policy-test/article-154873

[2] The European Commission published its final report, January 10, 2007, on the energy sector competition inquiry, concluding that consumers and businesses are losing out because of inefficient and expensive gas and electricity markets. Particular problems include high levels of market concentration; vertical integration of supply, generation and infrastructure leading to a lack of equal access to, and insufficient investment in infrastructure; and, possible collusion between incumbent operators to share markets.

[3] In the European countries where exchange-based transactions represent only a fraction of total electricity supply, this index may appear questionable.

[4] Contracts for future delivery of electricity also include a measure of CO_2 pass-through. Purchasers of electricity through such contracts ensure some protection against future volatility, including CO_2 price volatility

- *"Screen prices" with trading of blocks for baseload needs.*

In the UK, prices paid by industrial facilities can be set on broker or market electronic platforms (i.e., "screen pricing") through the trading of blocks (daily, monthly, trimester). Costs of intra-day adjustment are added to obtain the final supply cost. An exception to "screen pricing" is the long term contract signed between a power supplier and a generator where the electricity price is indexed to international coal prices and CO_2 prices.

In continental Europe, the main supply contracts are based on "screen prices" for annual blocks.

- *Annual contracts*

In Italy, prices are based on annual contracts via tenders.

- *Regulated tariffs* are found in Spain, in particular, although industry and generators are currently negotiating on long-term contracts based on coal-based generation costs.

Table EX 1 illustrates several electricity purchasing strategies theoretically available to energy-intensive industries (EII) in various regulatory environments - although we note that not all European countries offer all options shown below and not all industrial facilities are in a position to negotiate with generators for supply contracts in which case they accept the supply price that suppliers offer on the bilateral market.[5] For example, bilateral electricity supply contracts can be: indexed contracts (e.g., indexed on fuel plus CO_2 prices, on other commodities' markets, etc.); cross-market contracts (e.g., the spark spread option – the buyer of such a contract has the option to switch one unit of gas for one unit of electricity at a specified price); floating contracts including cap and floor prices; fixed price contracts; or contracts for differences (i.e., compensation is paid for price differences over periods agreed in advance).

Table EX1 assesses:

- Whether there is a strong link between the electricity price paid by the EIIs and the day-ahead price; and whether the different electricity purchasing strategies allow EIIs to hedge their electricity bills against power price variations.

- The extent to which each strategy involves a price risk from the industrial facility's view point, or allows risk sharing between generators and consumers (when the EII does not self-generate electricity). Risk sharing can occur, for example, from capital investment sharing or from price risk endorsement (i.e., both parties agree to supply prices that can be somewhat independent from the wholesale market prices). Does risk sharing allow lower price volatility exposure? Does it permit EIIs to pay prices lower than wholesale price levels – and thus limit increases in electricity prices due to CO_2 prices?

- Whether EII's purchasing strategies allow them to have choice of generation technologies from the supplier.

[5] Scandinavia has the most developed derivatives market, while in Italy or Eastern Europe, organised derivative markets do not exist.

Table EX 1: **Summary of Different Purchasing Strategies**

	RELATION TO DAY-AHEAD PRICE	**RISK BORNE BY EII**	**EII'S ROLE IN GENERATION TECHNOLOGY**
Annual power contracts for baseload for a single facility/company	Low	Low	None
Aggregation of purchasers	Low	Low	None
Aggregation of purchasers – share in payment of upfront cost of capital	Depends on the contract	Depends on the wholesale price level	Strong
Day-ahead price indexed contracts	Strong	Low	None
Fixed prices and quantities	None	Low	None
Fuel indexed contracts	None	Low	None
Cross-market contracts	None	Low	None
Floating price with a cap and a floor	Yes but in a limited manner	Low	None
Contract for difference	Low	Low	None
Regulated prices	Depends on the price setting body	Low	None
Investment in generation assets alone	Depends on the mark to market intensity	Full	Strong
Investment in generation assets with several owners	Depends on the mark to market intensity	High	Medium to strong

Whether or not industrial contract prices are below the market price (i.e., day-ahead) depends on the contractual agreement between the parties. One possibility to access electricity at a price that is lower than the general market price is through sharing the risk traditionally borne by generators alone. Some EIIs have agreed to take on part of the price risk undertaken generally only by the electricity generator (e.g., by securing long-term contracts, by sharing part of the investments, etc.).[6] The industrial buyer is thus in a stronger position to negotiate the contractual price. In doing so, however, it is also exposed to the risk of a lower market price in the future.

[6] It is not because generators and EIIs have decided to cross-subsidise EII at the expense of smaller users.

Electricity Price Risk Management

One characteristic of energy-intensive users is that their profitability varies strongly according to energy prices. If such producers are unable to transfer their cost volatility onto their prices, it is in their interest to minimise the cost components' volatility. Volatility is inherent to the electricity market, and electricity prices are more volatile than other fuel commodities. CO_2 prices and their associated volatility may have participated in increasing the electricity price volatility.

Although not all options are on the table for all regions, electricity users could rely on some of the following options to manage the electricity price risks.

- Some energy intensive industries may use the services of energy management companies that hedge against electricity price variations by purchasing derivatives, when available.

- Industrial users are increasingly seeking to aggregate electricity purchases in order to gain additional negotiation power, and sign tailor-made long term contracts. This could create a greater demand for technologies with more certain operating costs, including those less exposed to fuel and CO_2 price changes (e.g., nuclear).

- Several EIIs may also be willing to take direct stakes in power generation projects, and hence exchange (at least some) carbon and electricity price risk for the risk associated with equity ownership of power generation assets.

- Lastly, EIIs may decide to self-generate electricity to ensure their supply of base-load electricity at low cost. Ownership is a physical hedge against fluctuations in electricity prices.

How these possible strategies will play out in the bigger picture of electricity markets in the EU is difficult to gauge, yet they indicate that EII are interested in pursuing new purchasing strategies – all the more so as CO_2 prices have added a new cost to electricity generation. It will be interesting to see how, as these strategies become more common, they affect investment choices and lead to an effective response to the price of CO_2 through the promotion of less CO_2-intensive generation modes.

Policy Implications

There has been an intense debate between power producers, EIIs, and governments on the legitimacy of electricity price increase as a result of the CO_2 constraint – either because some power pools have low CO_2 intensities yet saw a general rise in prices as marginal price-setting plants are CO_2 intensive, or because CO_2-intensive plants have recorded large operational profits as the result of the CO_2 pass-through, which seems to fly in the face of the "polluter pays principle". The continuation of a free allocation of allowances to existing CO_2-intensive plants and new ones (through countries' new entrant reserve) may raise growing political problems. Auctioning allowances to the power producers may not alter all electricity price effects, but would avoid the need for governmental allocation and its associated political issues. This could be a measure establishing a more level playing field between competing installations in different countries with different emission caps. If auctioned, allowances could also generate revenues that can be used by governments in a number of ways, including to mitigate the cost to specific economic actors. For example, energy efficiency measures could be financed to facilitate a response to higher electricity prices.

Overall, whether through auctioning of allowances or other mechanisms, governments should reinforce the environmental effectiveness of any CO_2 constraint on power generation, and seek to address distributional issues.[7] Emissions trading systems are only acceptable if they eventually deliver emission reductions, while still offering flexibility to capped sources.

Electricity price uncertainty and CO_2 price volatility have strengthened the need for more predictable electricity costs for industrial facilities. Not all electricity markets facilitate this objective. Governments should consider whether there have been barriers to the development of price hedging instruments and other forms of purchasing strategies. New business models are starting to emerge to address rising price levels and price uncertainty - including CO_2 price volatility: investment in self-generation capacities (alone or multiparty); risk-sharing between generators and industrial consumers.

Governments implementing emissions trading systems should work to provide as much long-term visibility as possible on the required emission constraints to power generators. The fundamental question that policy-makers must face in the design of cap-and-trade systems that affect power generation is its ability to trigger sustained reductions in emissions through proper signals to investors. Ultimately, a low-CO_2 electricity system would carry a low cost of CO_2 for electricity users, delivering both the intended environmental outcome and closing the debate on windfall profits and high costs to EIIs.

If emissions trading is to be the instrument of choice for such a goal, its rules of operation must focus on providing least-cost options to lower CO_2 emissions, and should not be used to achieve other energy policy goals (e.g. energy supply diversity) that can fly in the face of lower CO_2 emissions. Other policy goals should be promoted via other measures. The alternative can only undermine the economic efficiency of emissions trading.

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[7] The alternative to opportunity cost pricing would be to only pass on to consumers the actual costs of meeting CO_2 objectives – i.e. any investment, and any purchase of CO_2 allowances to offset increased emissions. This "average cost" approach however blurs the CO_2 price signal for producers and consumers alike and could deliver a less efficient outcome overall.