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REGULATORY COMMISSION
FOR ELECTRICITY AND GAS

SURVEY

(F)080515-CDC-766

to complement

“survey (F)060309-CDC-537 on the impact of the EU Emissions Trading Scheme on Belgian electricity prices from 2005 to 2007”

15 May, 2008

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INTRODUCTION

This complementary analysis was commissioned by the CREG to update survey F060309-CDC-537, carried out in 2006 at the request of the Ministry for Energy, on the basis of currently available production and emission data.

Readers are referred to the earlier survey with regard to the following points:

- Presentation of the broad outline of the EU Emissions Trading Scheme (EU ETS), the breakdown of the European target into regional allocation plans and their impact on the production units of the electricity sector (part one);
- The theoretical approach to the impact using the concepts of opportunity cost and windfall profit (part three);
- The limitations of the theoretical approach (part four).

The present study was approved by the Executive Committee of the CREG on 15 May, 2008.

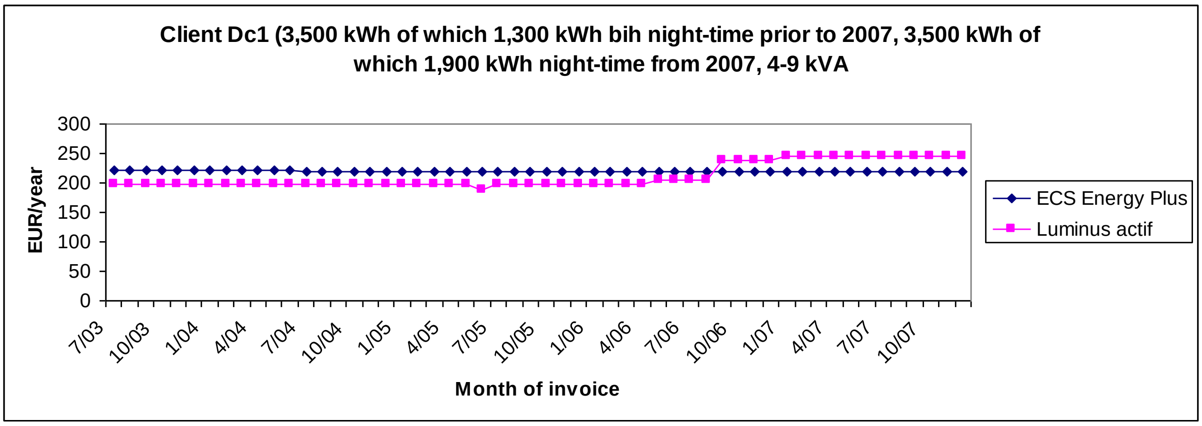
1. Estimate of windfall profits for Belgian electricity producers by market segments

1.1. Retail Market

1. The Walloon and Brussels markets were not fully liberalised until 1 January, 2007. The application of regulated prices to captive customers prevented the inclusion of any carbon costs.

2. In the case of low voltage supplies in the liberalised market, the tariff formulas of the two main suppliers have retained a similar structure to that of the captive market, consisting of factors index-linked to the parameters Nc and Ne. The following chart shows the changes in the bill of a Dc type customer with Electrabel and SPE after neutralisation of the changes in the Nc and Ne parameters.

Chart 1 – Changes in the bill of a domestic customer with constant Nc and Ne parameters



An analysis of this chart enables the formulation of the following observations:

- at Electrabel, this customer's bill has remained stable over the entire period. The two adjustments to the tariff formula that were implemented in July, 2004 (fixed term increase, reduction of the factors index-linked to parameters Nc and Ne) and in January, 2007 (extension of the night-time tariff at the weekend) were gauged so as not to have any major impact on a Dc1 consumer's bill;

- at Luminus, changes in the billing system were made in September, 2006, because Luminus was no longer in a position to keep its rates below those of Electrabel, and in January, 2007, to take into account the extension of the night-time tariff at the weekend.

Neither of these adjustments was made at a time of heavy rises in the allowance price. Without a more in-depth investigation into production costs, this leads to the conclusion that the opportunity cost of allowances was not passed through to the retail market selling price.

The pass through on this market was 0%.

1.2. Wholesale Market

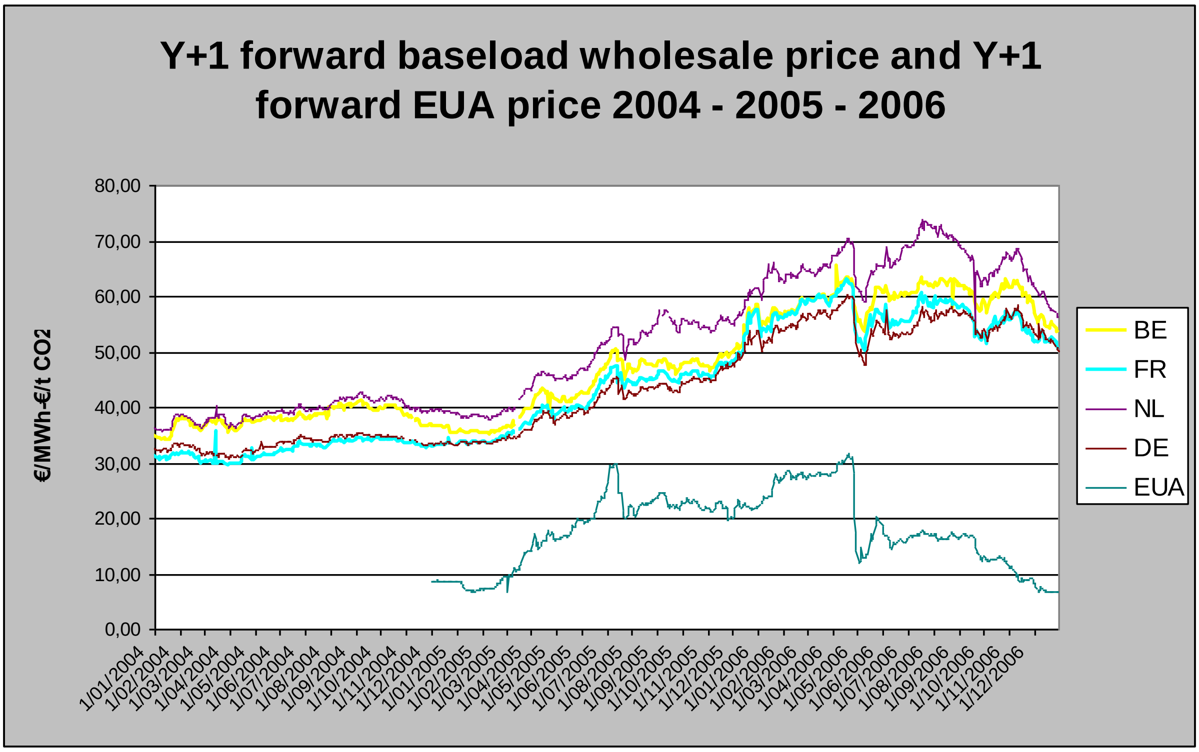
3. The day ahead market did not really take off until November, 2006, i.e. with the creation of Belpex. In 2007, trading on this market only represented 8.5% of the load on the Belgian grid. In the context of the present survey, the CREG has therefore focussed on the forward market, which moreover to a certain extent incorporates information derived from the spot market.

1.2.1. <u>Correlation between EUA price and electricity price</u>

4. In Belgium, the vast majority of transactions in the wholesale market are effected by means of bilateral forward contracts (OTC market).

5. The following chart shows changes in the EUAs (European Union Allowances) forward price and in the Y+1 forward market price of electricity in the wholesale markets of Belgium, France, the Netherlands and Germany.

Chart 2 – Changes in the electricity price and EUA price



Sources: Platts, Point Carbon

This chart shows, on the one hand, the steady move towards convergence between the French, Belgian and German markets, and, on the other hand, a particularly marked parallel trend in the allowance price and the electricity price from mid 2005 to early 2006, when EUA prices increased significantly.

In April 2006, when actual emission figures for 2005 were available, a market surplus became evident and the EUA price began to slide. Even though in early May, 2006, a concomitant reduction in the electricity price occurred, the trends of the two curves subsequently diverged. This illustrates the interaction of several factors in determining the price of electricity, the most important still being that of the fuel price. It is therefore very difficult to deduce from such a chart the allowances related component in the variation of the electricity price.

1.2.2. <u>Comparison of electricity price trends in the captive and liberalised markets</u>

6. In the captive market, the all-in tariff to customers connected to the transmission network was representative of average production and transmission costs, excluding CO_2, because the internalisation mechanism of greenhouse gas emission costs was not yet in

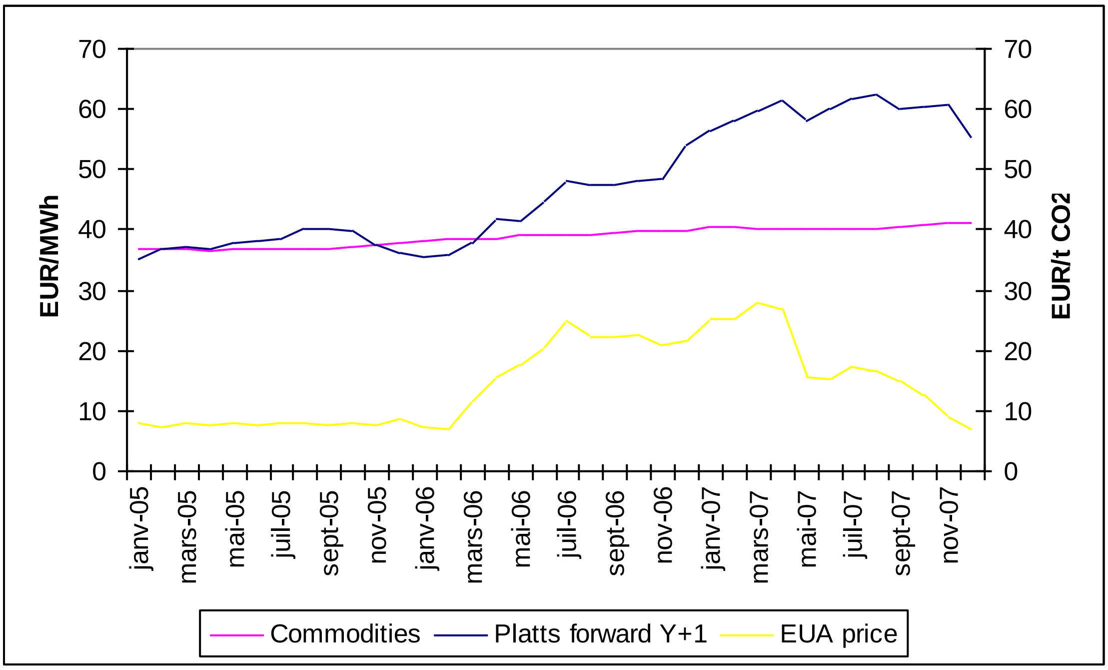
place. The CREG extended these rates by adjusting the values of the Nc and Ne[1] parameters, and then deducting the transmission rates as published by Elia to arrive at an estimated commodity price, excluding CO_2, as follows:

Tariff to all-in PIT[2] customers = 1.4338 X Nc + 28.3150 X Ne
- Elia transmission rate

= average electricity price, excluding CO_2

A comparison of this result with the market price (Platts Y+1 forward), as illustrated in the chart below, leads to the conclusion that the market price is practically always higher than the captive price, which may indicate that the carbon cost has been incorporated in the market price. This analysis does not, however, permit this fact to be established with certainty, given that tariff approaches are different. This is because the all-in tariff was based on average costs, whereas the market price reflects marginal costs[3]. This may in part explain the discrepancy found.

Chart 3 – Electricity price comparison of captive and liberalised markets



[1] The values used are those published on the CREG website for the analysed period.
[2] PIT = Production – Interconnection – Transport = customers not using the distribution network
[3] In the regulated market, the tariffs were determined so as to cover overall real production costs of the centralised generation facilities. It therefore represented the average production cost of the units involved. In the liberalised market, the price is in principle determined by the production cost of the last kWh sold. Hence the producer uses its production units in rising order of cost. This last kWh is therefore produced by the most costly operational unit.

For a number of reasons as raised in survey F060309-CDC-537, it is not possible to determine the pass through on this market. The CREG has nevertheless estimated the windfall profits by the methods and on the basis of the data presented below.

1.2.3. Calculation method and result

7. The method used is based on the marginal costs calculation.
The aim is to evaluate the rise in the selling price of electricity due to the introduction of the European Union Emissions Trading Scheme (EU ETS) and to apply it to the total kWh produced and sold in the wholesale market.

The calculation method involves four stages as described below, which can be summarised as follows:

For each hour:
Stage 1. Forward market price (with EU ETS) – forward selling price without EU ETS = Δ
Stage 2. If Δ >0; MIN (Δ, carbon cost of the marginal production unit with EU ETS)[4]
Stage 3. MIN X kWh total produced = windfall profit / hour
Total annual profit:
Stage 4. (∑ windfall profit / hour) X % of wholesale market sales

Some of the terms in these equations are known, others have to be estimated.

Stage 1: forward market price (with EU ETS) – forward selling price without EU ETS = Δ

Market Price

8. The forward market price with EU ETS is the market price as published by Platts for deliveries in one year's time. The CREG deemed that a day's production had been sold on the same day of the preceding year at the forward price applicable at that time. This enables a price weighting to be established without knowing when sales were effected.

[4] The aim is to determine to what extent the price rise observed at stage 1 covers the opportunity cost of CO_2 emissions in the marginal unit.

Selling Price without EU ETS

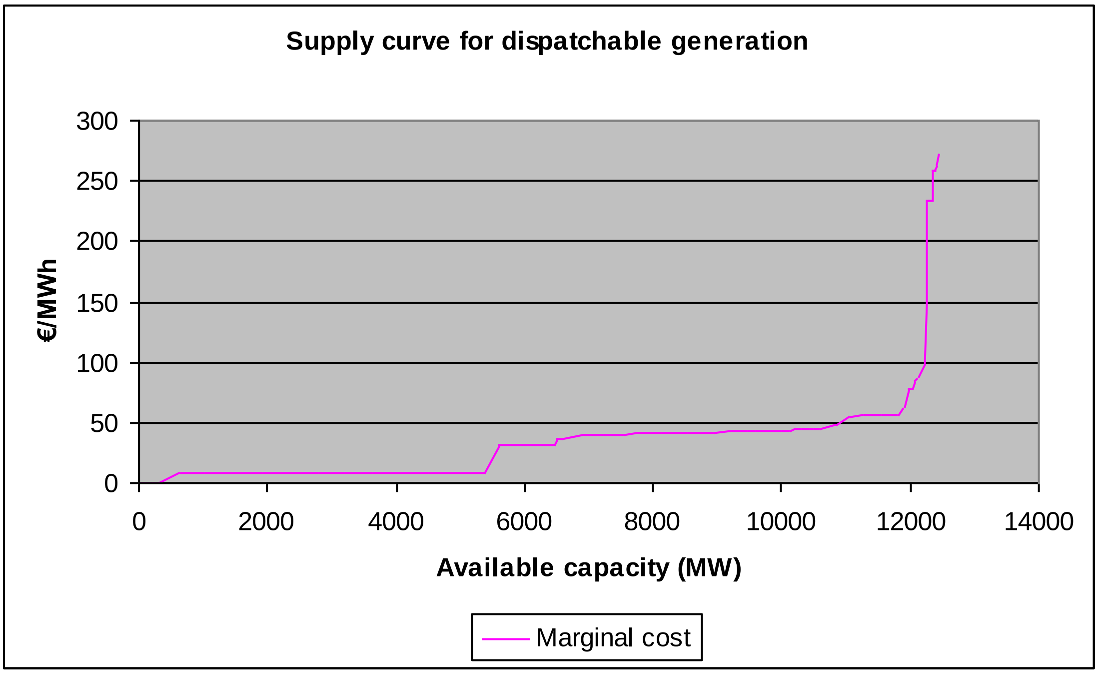
9. The selling price that would have been effective if the trading scheme had not been introduced is not known. In the absence of an appropriate model to accurately simulate the dispatching of production units and the interactions with foreign markets, the CREG has formed the following hypothesis:

The selling price without EU ETS = marginal cost without carbon of the Belgian marginal production unit.

a) Selection of production units

10. This necessitates calculation, for each hour in 2005, 2006 and 2007, of the merit order curve of production units suitable for determining the market price. The following chart is a representative curve of the Belgian market.

Chart 4 - Merit order of the centralised Belgian production facilities, including carbon



Source: CREG

In this chart, the various levels successively represent:

- Nuclear power stations;
- Hydraulic power stations;
- Biomass;

- Combined cycle gas turbines;
  Coal fuelled thermal power stations & gas fuelled thermal power stations;
- Open cycle gas turbines;
- Diesels;
- Turbojets.

The last three types are quite rarely used stand-by facilities. The CREG has assumed that their cost is not taken into account in the operator's selling price.

Nuclear power stations, at the other end of the curve, are never marginal. The actual production data indicate the presence of thermal power stations for each hour of the year. The marginal cost of nuclear power stations is therefore not likely to determine the market price either.

b) Determining the marginal cost of the marginal unit

11. Among the units taken into consideration, the CREG:
    - Has identified those operating at a given hour, based on the actual production data in quarter hours as supplied by Elia;
    - And attributed an operating cost to those units.

This approach assumes that the units used would have been the same without the trading scheme and that the fuel cost would have been identical. That would probably have been the case for part of the analysed period, given that the carbon price was too low to result in a fuel switch.

The short term marginal cost is determined as follows:

Short term marginal cost =	fuel costs + variable costs of O&M (Operation & Maintenance)

As neither the producer's fuel purchase contracts nor any detailed information on the operating costs of each production unit were available, the CREG used the following information:

Fuel Cost

12. Where information was available, the CREG used the Y+1 forward prices. Failing that, the spot prices effective at the time the sale contract was signed were taken into account (see table 1 below).

Proviso

Although spot prices undoubtedly play a part in determining forward selling prices, they are often volatile and incorporate very short term parameters (e.g. the temperature forecast of the days ahead).

The use of spot prices involves a major risk of overstating production costs and thereby understating the value of windfall profits.

Table 1 – Cost of Fuels Used

Fuel Type	Quotation	Description	Source
Gas	ZIG	Monthly average of spot quotations	DowJones
Coal	API#2	Cif ARA 2005: spot 2004 2006 and 2007: Y+1 forward	Argus McCloskey
Fuel oil	Brent	Brent crude futures positions 12 months	ICE / Theice
Gas from cokeworks	= coal		
Gas from blast furnaces	= coal		
Hydraulic	2005 indicative programme		Producers
Wood pellets	Neutralised by green certificates		

O&M Costs

13. Maintenance costs are taken from the indicative programme realised by the CREG in 2005.

The data for 2003 were increased to cover inflation at the rate of 2.5% p.a..

Output at stage 1:	forward selling price without EU ETS and discrepancy with forward market price.

Stage 2 – Identification of the carbon opportunity cost covered by the market price

a) Identification of marginal unit

14. A second calculation of merit order was undertaken after adding the carbon opportunity cost to the variable production costs as considered at stage 1.

The impact on the marginal cost is illustrated in the following diagrams.

Diagram 1 : Merit order without CO_2 allowances cost

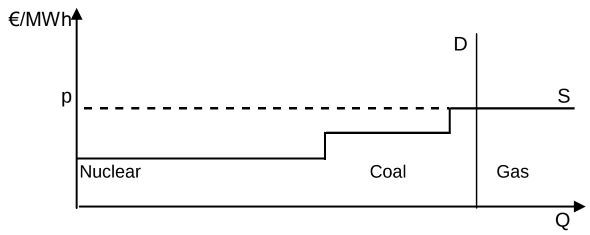
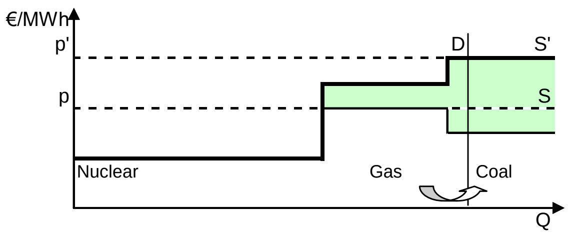


Diagram 2 : Merit order including CO_2 allowances cost



In this example, by adding the carbon opportunity cost, the marginal unit has become a coal based unit and the market price (P') incorporates the carbon opportunity cost of that unit.

Short term marginal cost = fuel cost + variable costs of O&M **+ CO_2 opportunity cost**

This calculation is based on the following data:

Table 2 – Cost of allowances taken up

Cost Type	Quotation	Description	Source
Carbon cost	From 01/01 to 30/11/2004: 8 EUR/t From 01/12/2004: EUA Price	No quotation published Y+1 forward	CREG estimate Point Carbon

The use of the forward carbon price is justified, as this is the price published at the time a term contract is signed and which is incorporated in the electricity selling price.

The operational power station with the highest marginal cost, inclusive of carbon, is identified for every individual hour.

b) Comparison of the carbon opportunity cost component of the marginal unit with the price differential as calculated at stage 1

15. The reasoning is illustrated by the following example:

If: Selling price without EU ETS: 50 EUR/kWh

Market price (with EU ETS): 55 EUR/kWh

Carbon cost of the marginal unit: 6 EUR/MWh

then: the price increase covers 83% (5 EUR/6 EUR) of the carbon cost component of the marginal unit.

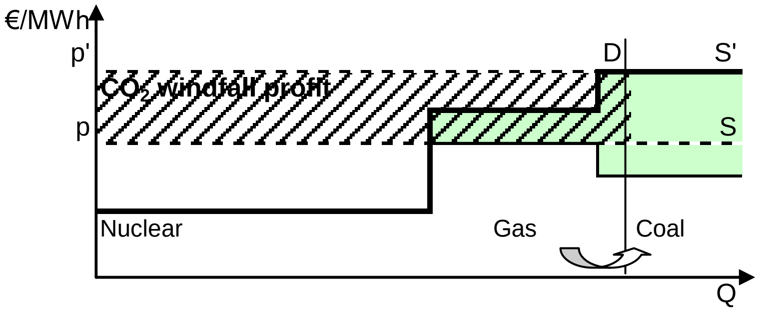
The aim is to identify the part of the carbon opportunity cost component in the marginal unit covered by the identified price rise. This calculation method overcomes the necessity of first having to determine a pass through rate.

Output at stage 2: per hour: carbon cost/MWh covered by the price rise.

Stage 3: Calculation of hourly windfall profit

16. The rise in the market price due to the incorporation in full or in part of the carbon opportunity cost of the marginal unit is applied to all kWhs sold which have been produced using submarginal units, as the following diagram illustrates.

Diagram 3 - Illustration of the windfall profit



To identify the windfall profit generated by all Belgian producers, the price rise calculated at stage 2 has to be multiplied by the appropriate volume. The reasoning as set out below was applied to determine this:

- Production by the stand-by units as identified at stage 1 is not taken into account, as their marginal cost is normally above the market price;
- Imported electricity supplies have not been taken into consideration. In this case, the windfall profit is actually generated by the foreign producer;
- Electricity produced in Belgium for export has been included because it is the Belgian producer who incorporates the carbon cost in its selling price;
- Electricity produced by power stations developed in association with private parties has been included in the count. There are numerous possible scenarios here, depending on the nature of the agreement signed (the business partner takes the electricity it requires and the electricity company markets the surplus, or the full electricity output is fed into the grid, and the business partner then purchases it at a negotiated price, etc.). It is therefore not possible to determine the share of the windfall profit allocated to each of the parties.
  Moreover, Electrabel and SPE are ARPs (Access Responsible Parties) for virtually all installations connected to the transmission network;
- The kWh taken up by Coo and Platte Taille at the pumping stage have been deducted.

=> volume taken into account =	kWh fed into the Elia grid – kWh produced by stand-by units.

Output at stage 3: estimated gross windfall profit per hour.

Stage 4: Estimated total net windfall profit

17. The hourly profits established in stage 3 are added up to arrive at an annual profit.

This represents the gross windfall profit, because it has been calculated across the total kWh produced (excluding peak production units). Hence, the carbon opportunity cost has probably not been incorporated in the selling price to low voltage customers, whose tariff formula is linked to the Nc and Ne parameters.

To obtain the net windfall profit, the CREG has therefore subtracted the Belgian produced share (table 3) from the overall production volume of electricity that is annually supplied to low voltage customers as advised by the distribution network operators (table 4).

The imported share of low voltage consumption does not need to be deducted, as it has not been taken into account at stage 3.

Table 3 – Share of Belgian consumption as covered by Belgian production

2005	2006	2007	Average
84%	79%	83%	82%

Source: CREG based on Elia data

Table 4 – Electricity quantity supplied to low voltage customers

DSO	2005 MWh	2006 MWh	2007 MWh	Total MWh
Total	**26.808.017**	**27.067.664**	**27.461.754**	**81.337.435**

Source: DSO Tariff Proposals

The calculation is as follows:

Gross windfall profit X [Q produced – (81,337,435 * 82%)] / Q produced

Output at stage 4: Estimated net windfall profit generated by electricity producers:

Table 5 - Estimated windfall profit generated by electricity producers in the Belgian wholesale market from 2005 to 2007

	2005 EUR	2006 EUR	2007 EUR	Total EUR	Annual average EUR	Average EUR/MWh sold on the wholesale market
Windfall profit	323.866.728	251.251.446	640.388.462	1.217.393.678	405.797.893	6,88

1.2.4. Verification of the Order of Magnitude of the Result Obtained

18. The CREG has carried out a verification of the order of magnitude of the result obtained:

- By estimating the average emission rate resulting from the production of the marginal MWh;
- By multiplying this by the annual average price of allowances (Y+1 forward);
- By multiplying the result by the quantity produced for the wholesale market.

Based on the efficiency of gas and coal based marginal units (regularly operating units with the lowest efficiency) and assuming that the marginal MWh is produced 40% from coal and 60% from gas, the average emission rate comes to 0.7t CO_2 per MWh. This calculation is detailed in the following table.

Table 6 – Average emissions of marginal units

		Fuel		Total
		Coal	Gas	
Carbon content	in kg CO_2 per GJ	95,95	55,83	
	in t CO_2 per MWh_{th}	0,35	0,20	
Marginal unit efficiency	%	36%	38%	
Marginal unit emissions	in t CO_2 per $MWh_{élec}$	0,96	0,53	
Distribution between fuel types	%	40%	60%	
Average emissions	in t CO_2 per $MWh_{élec}$	0,38	0,32	0,70

When the producer determines its offer price, it incorporates the opportunity cost of the allowances required to cover these CO_2 emissions.

This cost reflects the market price of the allowances. The arithmetical average of the Y+1 forward prices of EUA published by Point Carbon is:

8.04 EUR/t CO_2 for 2005;
18.18 EUR/t CO_2 in 2006;
18.13 EUR/t CO_2 in 2007.

If the pass through on the wholesale market is 100%, the 0.7 t CO_2 valued at their market price are incorporated in the selling price of each MWh produced for the wholesale market.

0,7 x [(2005 cost of allowances x Q produced in 2005 for the wholesale market)
+ (2006 cost of allowances x Q produced in 2006 for the wholesale market)
+ (2007 cost of allowances x Q produced in 2007 for the wholesale market)]
= 1,829,489,346 EUR.

The value of windfall profits amounts to 1,829,489,346 EUR for the period 2005 – 2007. The amount arrived at by the marginal cost method represents 67% of that value. The pass through is moderate, which would indicate that a calculation using the actual fuel purchase price would probably have resulted in a higher windfall profit.

2. The real cost of EU ETS to producers

This chapter aims to investigate the necessity of correcting the result of the marginal cost based method by any costs/income as a result of the allocation of allowances.

2.1. Allocation principles

19. In each region, the allocation of allowances is based on the grandfathering principle (allocation based on past emission levels), and possibly adjusted by means of benchmarking.

20. During the period 2005-2007, allowances were granted free of charge to Belgian electricity plants.

2.2. Producers' compliance with imposed limits

21. The following table shows the comparison between the authorised and actual emission levels of each installation within the centralised Belgian production network [5] within the EU ETS.

[5] Installations whose core business is the production of electricity for sale in the market place.

Table 6 – Centralised Belgian electricity production network: Allocated allowances and verified emissions

Power plant	Installed capacity (MW)	Type of power station	Fuel	Allowances 2005 - 2007 t CO_{2eq}	Emissions 2005 authorised t CO_{2eq}	Emissions 2005 actual t CO_{2eq}	Surplus/ shortfall t CO_{2eq}	Emissions 2006 authorised t CO_{2eq}	Emissions 2006 actual t CO_{2eq}	Surplus/ shortfall t CO_{2eq}	Emissions 2007 authorised t CO_{2eq}	Emissions 2007 actual t CO_{2eq}	Surplus/ shortfall t CO_{2eq}
Electrabel													
Flemish Region													
Electrabel Herdersbrug	460	CCGT	NG	2.858.560	952.853	806.612	146.241	952.853	846.536	106.317	952.854	878.277	74.577
Electrabel Vilvoorde	385	CCGT	NG	2.551.555	850.518	740.313	110.205	850.518	651.303	199.215	850.519	825.661	24.858
Electrabel Rodenhuize [(1)]	526	Thermal	FA, BF, CP	1.333.999	444.666	868.155	-423.489	444.666	733.842	-289.176	444.667	436.196	8.471
Electrabel Kallo	522	Thermal	NG	1.214.147	404.716	755.154	-350.438	404.716	653.388	-248.672	404.715	574.098	-169.383
Electrabel Ruien	546	Thermal	CP, FA	3.845.755	1.281.918	2.770.775	-1.488.857	1.281.918	2.310.547	-1.028.629	1.281.919	2.362.930	-1.081.011
Electrabel Drogenbos	460	CCGT	NG	2.574.032	858.011	1.112.264	-254.253	858.011	1.015.021	-157.010	858.010	1.022.042	-164.032
Electrabel Zandvliet Power	474	CCGT	NG	2.846.678	0	481.207	-481.207	1.708.007	1.018.902	689.105	1.138.671	1.107.551	31.120
Electrabel Mol	255	Thermal	CP, NG	1.720.769	573.590	1.209.419	-635.829	573.590	953.190	-379.600	573.589	976.785	-403.196
Electrabel Langerlo	602	Thermal	CP, FA	3.770.264	1.256.755	2.423.106	-1.166.351	1.256.755	2.177.699	-920.944	1.256.754	2.269.168	-1.012.414
Electrabel Langerbrugge	61	Cogen	NG	800.323	266.774	216.212	50.562	266.774	232.476	34.298	266.775	206.426	60.349
Electrabel turbojet Zeebrugge	18	Turbojet	LV	319	106	510	-404	106	394	-288	107	654	-547
Electrabel Turbojet Noordschote	18	Turbojet	LV	613	204	909	-705	204	409	-205	205	592	-387
Electrabel Turbojet Zedelgem	18	Turbojet	LV	339	113	306	-193	113	687	-574	113	689	-576
Electrabel Turbojet Zelzate	18	Turbojet	LV	434	145	916	-771	145	776	-631	144	705	-561
Electrabel Turbojet Aalter	18	Turbojet	LV	441	147	646	-499	147	656	-509	147	678	-531
Electrabel Turbojet Beerse	32	Turbojet	LV	1.269	423	1.680	-1.257	423	1.049	-626	423	1.436	-1.013
Total Electrabel Flemish Region				23.519.497	6.890.939	11.388.184	-4.497.245	8.598.946	10.596.875	-1.997.929	8.029.612	10.663.888	-2.634.276
Walloon Region													
Electrabel Baudour (Saint-Ghislain)	350	CCGT	NG	2.040.000	680.028	748.004	-67.976	680.028	833.301	-153.273	680.028	874.994	-194.966
Electrabel Amercoeur-Roux	256	Thermal	CP/CG	1.869.300	623.143	610.146	12.997	623.143	573.657	49.486	623.143	416.837	206.306
Electrabel Monceau	92	Thermal	CP/CG	660.000	220.000	1.260.520	-1.040.520	220.000	951.257	-731.257	220.000	337	219.663
Electrabel Flémalle (Awirs)	416	Thermal	NG, WP	2.424.900	808.261	394.640	413.621	808.262	235.113	573.149	808.262	360.072	448.190
Electrabel Bressoux				29.037	9.679	7.584	2.095	9.678	6.849	2.829	9.678	3.906	5.772
Electrabel Turbojet Turon	17	Turbojet	LV	5.100	1.703	899	804	1.702	535	1.167	1.702	769	933
Electrabel Turbojet Cierreux	17	Turbojet	LV	5.100	1.722	1.144	578	1.722	866	856	1.722	702	1.020
Electrabel Turbojet Deux-Acren	18	Turbojet	LV	5.100	1.676	1.033	643	1.676	370	1.306	1.676	679	997
Total EBL Walloon Region				7.038.537	2.346.212	3.023.970	-677.758	2.346.211	2.601.948	-255.737	2.346.211	1.658.296	687.915
Brussels Capital Region													
Electrabel Turbojet Schaerbeek	60	Turbojet	LV	3.520	1.630	358	1.272	1.630	149	1.481	1.630	240	1.390
Electrabel Turbojet Ixelles (Volta)	60	Turbojet	LV	3.580	2.170	955	1.215	2.170	301	1.869	2.170	301	1.869
Electrabel Turbojet Buda-Machelen	60	Turbojet	LV	3.570	2.060	797	1.263	2.060	669	1.391	2.060	641	1.419
Total Electrabel Brussels Region				10.670	5.860	2.110	3.750	5.860	1.119	4.741	5.860	1.182	4.678
Total Electrabel				**30.568.704**	**9.243.011**	**14.414.264**	**-5.171.253**	**10.951.017**	**13.199.942**	**-2.248.925**	**10.381.683**	**12.323.366**	**-1.941.683**
Essent - INESCO	42,2	CCGT	NG	**1.240.000**	**689.000**	**0**	**689.000**	**689.000**	**64.090**	**624.910**	**551.000**	**292.358**	**258.642**
SPE													
Walloon region													
SPE Seraing	460	CCGT	NG	2.681.400	893.751	825.175	68.576	893.751	819.890	73.861	893.751	828.845	64.906
SPE Angleur TGV1	158	CCGT	NG	523.500	174.510	115.801	58.709	174.510	78.849	95.661	174.510	103.220	71.290
SPE Moncin Seraing	70	Gas turbine		17.100	5.658	908	4.750	5.657	1.272	4.385	5.657	2.191	3.466
Total SPE Walloon Region				3.222.000	1.073.919	941.884	132.035	1.073.918	900.011	173.907	1.073.918	1.073.918	0
Flemish region													
SPE - Izegem				286.464	95.488	100.659	-5.171	95.488	98.099	-2.611	95.488	15.915	79.573
SPE Centrale Buitenring Wondelgem Gent	357	CCGT	NG	2.661.676	887.225	935.499	-48.274	887.225	708.055	179.170	887.226	619.214	268.012
SPE Centrale Harelbeke	83	Diesel	FA	86.858	28.953	36.897	-7.944	28.953	5.712	23.241	28.952	10.883	18.069
SPE centrale Ham 68 Gent	74	Diesel	FA	790.337	176.510	178.699	-2.189	306.913	114.232	192.681	306.913	108.294	198.619
	52	CCGT	NG										
Total SPE Flemish Region				3.825.335	1.188.176	1.251.754	-63.578	1.318.579	926.098	392.481	1.318.579	754.306	564.273
Total SPE				**7.047.335**	**2.262.095**	**2.193.638**	**68.457**	**2.392.497**	**1.826.109**	**566.388**	**2.392.497**	**1.828.224**	**564.273**
Total Belgium				**38.856.039**	**12.194.106**	**16.607.902**	**-4.413.796**	**14.032.514**	**15.090.141**	**-1.057.627**	**13.325.180**	**14.443.948**	**-1.118.768**
Total Flanders				**28.584.832**	**8.768.115**	**12.639.938**	**-3.871.823**	**10.606.525**	**11.587.063**	**-980.538**	**9.899.191**	**11.710.552**	**-1.811.361**
Total Wallonie				**10.260.537**	**3.420.131**	**3.965.854**	**-545.723**	**3.420.129**	**3.501.959**	**-81.830**	**3.420.129**	**2.592.552**	**827.577**
Total Brussels				**10.670**	**5.860**	**2.110**	**3.750**	**5.860**	**1.119**	**4.741**	**5.860**	**1.182**	**4.678**

Sources: NAP, ELIA, Climate registry

(1) Hyp: transfert allowances Arcelor idem 2006: 3.702.182

Synthesis 2005 - 2006

t CO_{2eq}	2005	2006	2007	Total
Electrabel	-5.171.253	-2.248.925	-1.941.683	-9.361.861
SPE	68.457	566.388	564.273	1.199.118
Essent	689.000	624.910	258.642	1.572.552
Total	-4.413.796	-1.057.627	-1.118.768	-6.590.191

Abbreviation Fuel type

NG	Natural Gas
BF	Blast Furnace Gas
CP	Coal Pulverized
CG	Cokes Gas
FA	Fuel A
LV	Light virgin Naphta
WP	Wood Pellets

For 2005, 2006 and 2007, only Electrabel exceeded its authorised emission levels. The surplus on the part of SPE is explained by its strategy of importing when the Belpex price is lower than its cost price. During these two years, all producers were able to stay within their allocated allowances to cover their actual emission levels. No fines were due therefore.

2.3. Costs met by producers

22. In view of the fact that the year N+1 allowance allocation precedes the refunding of allowances in respect of year N emission levels, Electrabel’s strategy was to await the end of the period. Allowance shortfalls were then purchased in 2007 at practically nil cost.

23. SPE had available allowances to cover the emission levels of a planned new power plant. When the project was abandoned, SPE could have sold these allowances at a good price, but it was unclear for a long time whether it was required to return them or not. SPE could only sell them in 2007, when the post adjustment refusal was confirmed by the European Commission. The profit from this sale was therefore quite negligible.

In conclusion, for the period 2005-2007, the windfall profits achieved do not have to be corrected by any actual allowance purchasing/selling costs/profits resulting from an allowance deficit/surplus.

3. Estimate of windfall profits in the UK and Spain

24. Recently, two regulatory bodies, OFGEM (the British regulator) and CNE (the Spanish regulator) established the value of producers' windfall profits. The CREG has analysed their calculation method.

3.1. The UK

25. OFGEM values the extra profits generated by electricity producers in the UK over the period 2008 – 2012 at 9 billion GBP due to large numbers of allowances being granted free of charge.

This result is established as follows:

Allowances allocated to electricity producers	99.534.205	tCO_{2eq}/year
Market price of allowances	25	EUR/tCO_{2eq}
Annual income	2.488.355.125	EUR
Income 2008 - 2012	12.441.775.625	EUR
	9.082.496.206	GBP

Sources: NAP, OFGEM

OFGEM proposes that the State recover such gains by taxing windfall profits in order to support households experiencing difficulties in paying their energy bills (households that spend more than 10% of their income on energy).

26. This announcement has to be seen in the context of the British electricity market, which is characterised by two determining factors:

- It has very few connections to other markets. Producers therefore experience only very little competition from abroad and are in a position to determine the price on the wholesale market. As a result, they can also to a large extent pass the carbon opportunity cost on in their wholesale pricing;
- The selling price of electricity to domestic customers is linked to the wholesale market price. Incorporation of the opportunity cost of allowances in the electricity price explains a portion (estimated at 60 GBP/p.a.) of the rise in the average electricity bill;

- At the beginning of 2008, the 6 principal energy suppliers announced substantial price increases to household customers:

Supplier	Price Increase
Mpower	+ 12.7%
EDF	+ 7.9%
British Gas	+ 15%
Scottish Power	+ 14%
E.On	+ 9.7%
Scottish and Southern Energy	+ 14.2%

Source: BBC News - Business

27. However, OFGEM has reservations regarding the accuracy of this amount and accepts that it may be debatable. The actual amount is probably less, since:

- Producers who have negotiated long-term fixed price sale contracts are not in a position to increase their prices to incorporate the opportunity cost of allowances;
- Some suppliers may decide not to pass on the opportunity cost of allowances in their selling price.

OFGEM does, however, consider the amount to be significant and may set up a fund to alleviate poverty.

28. The tax on windfall profits proposed by OFGEM seems unlikely to be introduced. The Chancellor of the Exchequer’s spokesman has declared that a tax on windfall profits is not on the Government’s agenda. Moreover, such a tax on production would result in inequality of treatment of the various market players, as suppliers who do not actually produce their electricity would not be affected whereas producers who do not sell direct to end users would be.

In order to resolve the issue, the government wants the European Union to decide in favour of auctioning the majority of allowances from 2012.

29. The government has focused on negotiating a fuel poverty plan with the industry. On 23 April, 2008, energy suppliers (gas and electricity) agreed on a package of measures, including an increase in their contribution to social support schemes.

This was 50 million GBP in 2007 – 2008 and will go up to:

- 100 million GBP in 2008 – 2009;
- 125 million GBP in 2009 – 2010;
- 150 million GBP in 2010 – 2011.

i.e. an additional contribution of 225 million GBP over 3 years.

The agreement will apply until 2011, but the Government anticipates that a contribution worth at least 150 million GBP per annum will continue to be raised thereafter.

3.2. Spain

30. Up to 2006, regulation rendered the Spanish market uncompetitive. In 2006, 75% of sales were effected at the regulated price, below the day-ahead market price (in 2005, 95% of energy was traded on the day-ahead market).

Such regulated tariffs caused competitors to leave the market and did not encourage the emergence of a forward market (intended to secure supplies in a volatile market).

Moreover, the lack of correlation between regulated all-in tariffs fixed annually by decree and the actual cost of production which is affected by fuel and EUA prices has led to substantial losses:

3.8 billion EUR in 2005;
3 billion EUR in 2006;
1.5 billion EUR in 2007.

The State has undertaken to reimburse producers over the coming years.

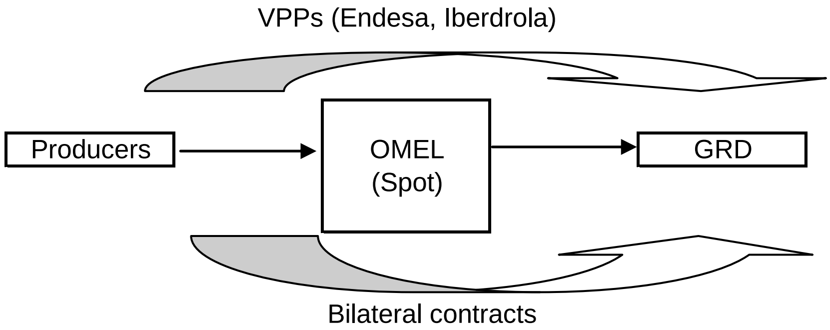
31. To remedy the situation and to fix tariffs in the regulated market so as to take account of energy costs, a wholesale market (pool) has been created and an auction mechanism set up.

Distribution network operators (DNOs) can acquire the electricity intended to supply captive customers by bidding in forward contract auctions. Moreover, in order to enable new suppliers to enter the market, the two principal producers have had to put VPPs (Virtual Power Plants) up for sale.

a) Wholesale market operating mechanism

Since June, 2007, supplies have been procured by companies signing transparent bilateral contracts (for baseload and peakload) for 3 months at auctions (the first having been held on 20/06/2007).

Diagram 4 – How the pool works



This market price becomes the basis for fixing the regulated tariff (updated every three months).

b) Mechanism to neutralise windfall profits

Retrospectively, the authorities bill producers for the average CO_2 cost component of the market price. The carbon cost therefore does not affect the retail price.

The repayment totals are as follows:

2006:	1.2 billion EUR
2007:	100 million EUR (on account of the low EUA price)
2008 (e):	1.4 billion EUR
Total	2.7 billion EUR

Repayments will have to be effected by 2012.

For 2006, CNE has calculated the following repayments by the main producers:

Endesa:	406 million EUR
Iberdrola:	318 million EUR
Union Fenosa:	157 million EUR
Gas Natural:	74.5 million EUR

The calculation method for the year 2006, determined by ministerial decree ITC/3315/2007 of 15 November, 2007, is applicable to standard regime production installations (the special regime applies to renewable energies) and is as follows:

- <u>For production units not subject to EU ETS</u>

Amount to be deducted =	Q energy sold in the wholesale market X emission factor of a CCGT (0.365 tCO_2/MWh) X average EUA price

- <u>For production units subject to EU ETS</u> and therefore in receipt of allowances free of charge

Amount to be deducted =	no. of allowances granted free of charge X market price of allowances X (emission factor of a CCGT/ emission factor of the plant)

32. By a decree of 7 December, 2007, the clawback system was extended to the period 2008-2012.

33. Some see this mechanism a means for the State to cut its debt to producers.

34. The majority of producers have initiated legal proceedings against the Government decision to reduce by 1.2 billion EUR the amounts owed to them for 2006. Endesa estimates that the effect of this measure on the producers' balance sheets will lastingly undermine the confidence of investors, which could ultimately affect the security of the country's energy provision.

4. Conclusion

35. For all the reasons raised in survey F060309-CDC-537, it is not possible to accurately determine the impact of allowance prices on the price of electricity.

36. For a more detailed calculation, the CREG would as a minimum need accounting data relating to:

- The fuel purchase price;
- The variable cost of O&M for each thermal production unit;
- The electricity selling price;
- The price of buying in allowance shortfalls.

It would also need information on how selling prices are set by producers when negotiating their OTC contracts.

37. Based on the available information, the CREG has nevertheless been able to establish that the selling price of electricity usually enabled the carbon opportunity cost of the marginal production unit to be partly or wholly covered. This price increase on all kWh produced has enabled electricity producers within the Belgian transmission network to generate an estimated windfall profit of **1.217 million EUR** in the period 2005-2007.

On behalf of the Regulatory Commission for Electricity and Gas:

Guido Camps	Dominique Woitrin	François Possemiers
Director	Director	Executive Board Chairman