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Introduction of CO_2 Emission Certificates in a Simplified Model of the Benelux Electricity Network with Small and Industrial Consumers

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Introduction of CO_2 Emission Certificates in a Simplified Model of the Benelux Electricity Network with Small and Industrial Consumers

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***Abstract*--This paper addresses a problem arising from the introduction of the Emission Trading System in Europe (EU-ETS). Electricity intensive industrial consumers are currently facing a high price of electricity, which affects their competitiveness and may force them to leave Europe. We explore the possibility of developing special contracts, which would limit the impact of CO_2 prices on electricity intensive industrial consumers. The models presented reveal several innovative aspects to the extent that it involves two pricing mechanisms. One of them introduces a perfect competition market where all consumers are price-takers and purchase electricity at a price based on the short run marginal costs. The other mechanism applies average cost prices to large industrial consumers.**

The analysis of these problems is dealt with simulation models applied to the Northwestern Europe market.

The mathematical optimization models developed are implemented using the GAMS modeling system.

***Index Terms*--Average cost price, electricity market, EU-ETS, industry sector.**

I. Introduction

In accordance with the Kyoto Protocol, the aim of the European Emission Trading Scheme (EU-ETS) consists in reducing gas emissions from human activities provoking climate changes. The EU Member States must decrease gas emissions by 8% from the 1990 levels by the end of the first compliance period defined by the Kyoto Protocol.

As stated by Directive 2003/87/EC, the carbon emissions restriction has entered in force at the beginning of 2005 and it is based on a cap and trade system, which defines the maximum amount of CO_2 emissions per compliance period and allocates a corresponding number of allowances that give the authorization to emit. Most allowances are assigned free of charges and companies can either use these permits to cover the emissions resulting from the production of their installations or sell them on the market. Carbon pricing is the main strategy used to tackle climate change. All European countries taking part in the ETS had to set up National Allocation Plans (NAPs) for the first commitment period 2005-2007, indicating the amount of allowances per CO_2 emitted that would be distributed among the firms involved in polluting production activities (see [2]). Therefore, emission caps were set up based on historical data and reduction aims. If the individual production of one firm exceeds its emission allowances, additional certificates have to be purchased on the market. This is the functioning of the CO_2 trading system.

However, the analysis of the effects of the application of this carbon restriction policy shows that several improvements are needed in order to limit market inefficiencies and drawbacks. The ETS is currently being reviewed by the European Commission, which has the intention to modify part of the directive.

The present paper studies one of the effects provoked by the EU-ETS. Industrial consumers are currently facing a high price of electricity, which reduces their competitive positions on international markets. They are evaluating the possibility to transfer their production activities to extra-Community countries, where carbon dioxide emissions are not constrained. This would be a serious welfare loss for the European Member States and, generally, a defeat of the ETS policy, the largest cap and trade system in the world.

Industries invoke several reasons for leaving. Among them, they complain that power generating companies pass the price of CO_2 allowances in the marginal costs of electricity, even if allowances are mainly grandfathered. This increases the probability of creation of windfall profits (see [4]) for the power companies, especially for the ones which rely on nuclear technologies; it also reduces industry competitiveness on the international market (see [3]). As a result, large industrial consumers require special contracts whereby they may procure electricity at a lower price.

We explore the possibility to apply these special contracts. We, first, consider a reference case where all consumers (small and industrial ones) are price takers and operate in a perfect competition environment. In this case, we check the effects of the introduction of the EU-ETS and we show that industrial consumers' complaints are founded. We, then, introduce the average cost pricing

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mechanism and we apply it to the industrial sector. This new approach accounts for the industrial consumers' capability to finance the operation of large base-load power plants. In short, we assume that part of the power capacity installed in the market is dedicated only to industrial consumers and they will pay the full costs (variable and fixed charges) associated with those installations. Consequently, they have under their direct control all the power stations they need to cover their demands.

There are two are implications of this innovative pricing system: the market segmentation and the capacity splitting between the two consumer groups regarded.

Specifically, the analysis is applied to the so-called Benelux network (Belgium, France, Germany and The Netherlands). Market simulations are calibrated with data updated to 2005. The designed power system is composed of 15 nodes, which are connected by 28 arcs represented by linearized direct-current (DC) load flow using the Power Transfer Distribution Factor (PTDF) matrix provided by ECN (see [1]). Ten of these connections are trans-border lines and they are not limited in capacity. Supply and demand are located at the seven nodes depicted in Fig.1.: two in Belgium (Merchtem, Gramme), three in the Netherlands (Krimpen, Maastricht and Zwolle), one in Germany ("D") and, finally, one in France ("F"). The remaining German and French nodes are passive and they are only used to transfer electricity.

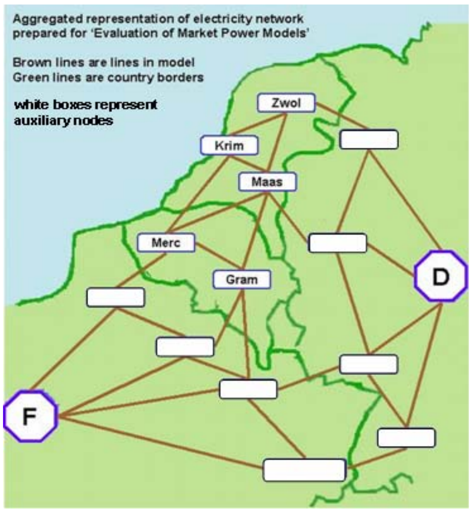

Fig. 1. Simplified Northwest Europe Market

We include 8 different technologies[1], which are ranked in merit order. They have proper emission rates, fuel costs and capacities. Power plants are owned by 9 electricity generating companies[2]. We use step-wise marginal cost curves to represent supply functions per node and technology. Two temporal periods (peak and off-peak times) with different durations are modelled[3]. Consumers' demand functions are assumed to be linear and differing in each node. The retail sector requires much more power in winter (the peak period) than in summer (the off-peak period); while industrial consumers need a constant quantity of electricity over time.

Since we are interested in analyzing consumers' behaviour, we account only for the long-run term. Small consumers are expected to behave less flexible in case of changes in prices, thus we set their demand elasticity at -0.1 in the reference point. On the other hand, to account for the ability of large consumers to leave Europe in case of high electricity prices, we assume that their specific elasticity is equal to -1. Finally, allowances price is endogenously determined.

The rest of the paper is organized as follows. Section 2 presents the basic reference model and the concerning results. Section 3 introduces the average cost price formulation and explains the results obtained. Section 4 concludes.

II. Reference Case

In order to check the impact of the application of the EU-ETS on electricity prices and consumers' demand, we first simulate a perfect competition market without emission certificates and, then, we introduce the emission balance equation. Both models are based on the nodal price approach that explicitly takes into account the network characteristic. In fact, the transmission constraints, included in the form of the PTDF matrix, affect the electricity prices, making them different over nodes[4].

The scenario accounting for the emission and the transmission constraints is meant to represent the reference case.

A perfect competition market where all agents are supposed to be price takers and maximize their respective surpluses is represented. Electricity generating companies supply both industrial and small consumers: there is no market segmentation. The two consumer groups buy electricity at the same price. The assumption that industries need a constant level of electricity over the year makes our analysis more realistic.

The following subsections describe the optimization model and the relative results in details. Dual variables are introduced within parentheses on the right side of the constraints with which they are matched.

A. Indices and Sets

The two temporal periods considered are explicitly modeled. The apexes s and w indicate respectively the summer off-peak and the winter peak periods. Instead, industrial and small consumer segments are represented by the respective indexes *1* and *2*. The following data sets characterize the reference model:

[1] We account for hydro, wind, nuclear, lignite, coal, CCGT, natural gas and oil-based power stations.

[2] Electricity is provided by 8 main companies: E.ON Energie AG, Electrabel SA, Electricité de France, ENBW Energieversorgung Baden-Württemberg, Essent Energie Productie BV, Nuon, RWE Energie AG, Vattenfall Europe AG. A ninth generator, called "fringe" represents the remaining small generators.

[3] The off-peak period lasts seven months (5136 hours), while the peak period covers the remaining 5 months (3624 hours).

[4] That is the idea of nodal prices.

$i = 1,...7$ Active nodes;

$f = 1,...9$ Electricity generating companies;

$m = 1,...8$ Types of technologies used to produce electricity;

$l = 1,...28$ Number of the lines composing the transmission grid.

B. Variable and Parameters

This subsection introduces all the main variables and parameters included in the model. They are divided into groups.

Generating Companies' variables

$g_i^{s,w}$ Hourly MW of power sold at node *i* in summer and in winter;

$gp_{f,i,m}^{s,w}$ Hourly MW of power generated by plant *m* owned by firm *f* at node *i* in each period;

$inj_i^{s,w}$ Net flow corresponding to the difference between the total amounts of power sold and demanded in each node *i* and period;

$\eta_i^{s,w}$ Dual variables representing the marginal production costs;

$\nu_{f,i,m}^{s,w}$ Dual variables defining the scarcity rents associated with each power plant *m*.

Generating Companies' parameters

$G_{f,i,m}$ MW of unit *m* owned by firm *f* at node *i*;

$mc_{f,i,m}$ Marginal costs in €/MWh of unit *m* owned by firm *f* at node *i* in each period.

Consumers' variables

$d_i^{s,w,1}$ Hourly MW of power demanded by industrial consumers located at node *i* in summer and in winter;

$d_i^{s,w,2}$ Hourly MW of power demanded by small consumers located at node *i* in summer and in winter;

$P_i^{s,w,1}(d_i^{s,1})$ Inverted demand function representing the industrial consumers' willingness to pay;

$P_i^{s,w,2}(d_i^{s,2})$ Inverted demand function representing the small consumers' willingness to pay.

Price variables

$p_i^{s,w}$ €/MWh price of electricity at node *i*;

$phub^{s,w}$ €/MWh price of electricity set at the hub node, which represents a virtual market where all electricity asks and bids meet together. In our formulation, the German node assumes this role.

EU-ETS variable and parameters

λ Allowances price in €/ton (variable);

NAP_f National Allocation Plants per firm *f*;

E Emission cap of the market analyzed;

em_m Emission factor per unit *m*.

Network variables and parameters

$\mu_i^{s,w,+}, \mu_i^{s,w,-}$ Congestion and transmission costs at each node *i* in each period (variables);

$PTDF_{l,i}$ Power Transfer Distribution Factor matrix. It defines the proportion of power flow injected at *i* and withdrawn at the hub, which passes through the grid line *l*. These proportions allow one to compute the flow on the lines for different patterns of injection and withdrawal;

$Linecap_l$ Upper MW limit for flow through line *l*.

Period durations

$hour_i^{s,w}$ Duration in hours of the off-peak and peak periods.

C. Model without emission constraint

In a perfect competition market, both companies and consumers maximize their respective surpluses as price takers. In this section, we specify the equations and constraints characterizing the basic cases. We start with the definition of the generating companies' maximization problem; then, we analyze the consumers' model and, finally, we describe the network constraints that influence the equilibrium of the entire market.

Generators maximize their annual profits defined by (1). Production and transmission charges are the costs included in the problem. Generators don't really pay transmission costs, since they include them into the electricity prices. They assume an intermediate position between final consumers and national TSO, with the task to transfer wealth from one side to the other. Since there is no market segmentation, producers apply the same electricity price to both consumer groups in each period.

$$\begin{aligned}
\max \quad & \sum_i p_i^s \cdot g_i^s \cdot hour_i^s + \sum_i p_i^w \cdot g_i^w \cdot hour_i^w \\
& - \sum_{i,m} mc_{f,i,m} \cdot gp_{f,i,m}^s \cdot hour_i^s - \sum_{i,m} mc_{f,i,m} \cdot gp_{f,i,m}^w \cdot hour_i^w \\
& - \sum_{l,i} PTDF_{l,i} \cdot inj_i^s \cdot (\mu_i^{s,+} - \mu_i^{s,-}) \cdot hour_i^s \\
& - \sum_{l,i} PTDF_{l,i} \cdot inj_i^w \cdot (\mu_i^{w,+} - \mu_i^{w,-}) \cdot hour_i^w
\end{aligned} \tag{1}$$

Subject to:

$$inj_i^s = g_i^s - d_i^{s,1} - d_i^{s,2} \tag{2}$$

$$inj_i^w = g_i^w - d_i^{w,1} - d_i^{w,2} \tag{3}$$

$$\sum_{f,m} gp_{f,i,m}^s - g_i^s = 0 \qquad (\eta_i^s) \tag{4}$$

$$\sum_{f,m} gp_{f,i,m}^w - g_i^w = 0 \qquad (\eta_i^w) \tag{5}$$

$$G_{f,i,m} - gp_{f,i,m}^s \geq 0 \qquad (\nu_{f,i,m}^s) \tag{6}$$

$$G_{f,i,m} - gp_{f,i,m}^w \geq 0 \qquad (\nu_{f,i,m}^w) \tag{7}$$

Conditions (2) and (3) define the injection variables equations. The energy balances at each node and period are introduced by constraints (4) and (5). Both in peak and off-peak times, the total quantity of electricity produced has to correspond to the amount of power supplied. The dual variables paired with these two equilibrium conditions are the marginal production costs. Generation capacity limits are represented by inequalities (6) and (7). Since power plants are put in merit order, we introduce the associated scarcity rents as shadow variables.

On the other side, consumers desire to maximize their annual surplus. Since generating companies do not apply any market segmentation, the nodal electricity prices paid by large and small electricity users are identical; they vary only per period. The difference between the two consumer groups consists in the fact that industrial consumers require a constant level of electricity. Conditions (8) and (9) define respectively the industrial and the small consumers' maximization problems. In both cases, quantities demanded must be positive.

$$\max \int_0^{d_i^{s,1}} P_i^{s,1}(\varepsilon)\cdot d\varepsilon \cdot hour_i^s + \int_0^{d_i^{w,1}} P_i^{w,1}(\varepsilon)\cdot d\varepsilon \cdot hour_i^w - p_i^s \cdot d_i^{s,1}\cdot hour_i^s - p_i^w \cdot d_i^{w,1}\cdot hour_i^w \quad (8)$$

$$\max \int_0^{d_i^{s,2}} P_i^{s,2}(\varepsilon)\cdot d\varepsilon \cdot hour_i^s + \int_0^{d_i^{w,2}} P_i^{w,2}(\varepsilon)\cdot d\varepsilon \cdot hour_i^w - p_i^s \cdot d_i^{s,2}\cdot hour_i^s - p_i^w \cdot d_i^{w,2}\cdot hour_i^w \quad (9)$$

Constraint (10) sets the equality between large summer and winter hourly demands. It is matched with the dual α_i .

$$d_i^{s,1} - d_i^{w,1} = 0 \qquad (\alpha_i) \qquad (10)$$

Because electricity cannot be stored, in each hour, the total amount of electricity supplied equals customers' demand.

$$\sum_i g_i^s - \sum_i d_i^{s,1} - \sum_i d_i^{s,2} = 0 \qquad (phub^s) \qquad (11)$$

$$\sum_i g_i^w - \sum_i d_i^{w,1} - \sum_i d_i^{w,2} = 0 \qquad (phub^w) \qquad (12)$$

The summer and the winter prices set at the hub node match the market balance equations (11) and (12).

The network constraints, according to the direct-current (DC) representation, are introduced by conditions (13), (14), (15) and (16). The power flow has to be lower than line capacities. Depending on the direction of the flow, the inequalities yield the dual transmission prices, indicated in parenthesis, which affect electricity prices, making them different over nodes. This reasoning holds both in peak (constraints (14) and (16)) and off-peak (constraints (13) and (15)) periods.

$$Linecap_l - \sum_i PTDF_{l,i}(g_i^s - d_i^{s,1} - d_i^{s,2}) \geq 0 \quad (\mu_l^{s,+}) \qquad (13)$$

$$Linecap_l - \sum_i PTDF_{l,i}(g_i^w - d_i^{w,1} - d_i^{w,2}) \geq 0 \quad (\mu_l^{w,+}) \qquad (14)$$

$$Linecap_l + \sum_i PTDF_{l,i}(g_i^s - d_i^{s,1} - d_i^{s,2}) \geq 0 \quad (\mu_l^{s,-}) \qquad (15)$$

$$Linecap_l + \sum_i PTDF_{l,i}(g_i^w - d_i^{w,1} - d_i^{w,2}) \geq 0 \quad (\mu_l^{w,-}) \qquad (16)$$

Equalities (17) and (18) show the role assumed by transmission costs in defining nodal electricity prices. Depending on the grid congestion level and on their location in the network, consumers pay different power prices.

$$p_i^s = phub^s + \sum_m (-\mu_l^{s,+} + \mu_l^{s,-}) \cdot PTDF_{l,i} \qquad (17)$$

$$p_i^w = phub^w + \sum_m (-\mu_l^{w,+} + \mu_l^{w,-}) \cdot PTDF_{l,i} \qquad (18)$$

D. Introduction of the emission constraint

We adopt an emission cap E of about 397 Mio. ton. p.a. It is given by the sum of the NAPs of the electricity sector of the countries included in the simulation tests and defines the overall amount of emission allowed (see [2]). The certificate price λ results as a shadow price from the emission constraint, which has to be introduced into the model:

$$E - (\sum_{i,m} gp_{f,i,m}^s \cdot em_m \cdot hour_i^s + \sum_{i,m} gp_{f,i,m}^w \cdot em_m \cdot hour_i^w) \geq 0 \ (\lambda) \quad (19)$$

Condition (19) says that the total amount of electricity produced over the year (hourly generation times the hours of each period) must not exceed the annual emission cap E. If the emission constraint is binding, i.e. it equals zero, the value of λ will be positive.

With the application the ETS, generating companies have to include the emission costs in their profit function. It means that condition (1) has to be modified adding the following term:

$$\lambda \cdot (NAP_f - (\sum_{i,m} g_{f,i,m}^s \cdot em_m \cdot hours_i^s + \sum_{i,m} g_{f,i,m}^w \cdot em_m \cdot hours_i^w))$$

E. Analysis of the reference case results

In order to check the impacts of the application of the ETS on the industrial consumer segment, we ran the basic model first without and then with an emission constraint. The model with emission constraint is assumed to be our reference case. We focus our attention on the relative changes in industrial consumers' electricity demand and prices. Moreover, information about technology production mix is provided[5].

The implementation of the ETS causes a general decrease of -12% in industrial consumers' hourly electricity demand both in peak and off-peak periods[6], accompanied by a reduction of -21% in their annual surplus. The highest relative change in demand occurs in Germany (-23%), followed by the Dutch node Zwolle

[5] Our purpose consists in analyzing industries' behavior in the long-run term. The reader should keep in mind that the large consumers' elasticity has been set at -1. All results are influenced by this initial condition.

[6] Industrial hourly demand does not differ per period. That is the reason why the fall of their electricity demand is identical in summer and in winter.

(12%). The other two Dutch locations Krimpen and Maastricht register respectively reductions of -6% and -7%. In Belgium, the decrease is lower (-2% in Merchtem and -3% in Gramme) and, finally, France has only a fall of -1%. In practice, this would mean that industries might consider, as alternative solution, the possibility of leaving Europe in the long-run term and installing their production activities elsewhere.

The ETS inter-temporal effects on electricity prices are not trivial at all. Electricity price variations have a different trend per period.

Table I shows the electricity prices in the case with emission constraint.

TABLE I
ELECTRICITY PRICE UNDER EU-ETS (€/MWH)

Nodes	Summer	Winter
Germany	45.09	47.34
France	5.09	47.34
Merchtem	47.20	47.34
Gramme	27.89	47.34
Krimpen	47.20	47.34
Maastricht	47.20	47.34
Zwolle	46.33	47.34

In summer, transmission costs influence power prices. In fact, some of the connections are congested. In particular, the grid is overloaded between France and Germany and between France and Belgium. The arc linking the Belgian node Merchtem with the Dutch node Krimpen is satured and the same happens between Gramme and Maastricht. The directions of the flows reveal that France exports both to Germany and Belgium, which, in its turn, supplies the Netherlands. Great part of the French electricity, produced by nuclear stations, is exported and the related transportation costs, combined with marginal cost pricing implicit in this model, make French power very cheap (5.09 €/MWh).

In winter, the transmission grid is no longer congested and all consumers pay the price set at the hub node. This happens only when we introduce the emission constraint in the model.

Comparing those electricity prices with the ones got when the emissions regime is not binding, one can notice that, under the EU-ETS, electricity prices raise in summer. Those results are aligned with the decrease in the amount of electricity supplied. German consumers meet the highest price increase (it's about +131%), followed by the consumers located at the Dutch node Zwolle (+51%) and at the Belgian node Gramme (+43%). In Merchtem, Krimpen and Maastricth the relative change in price is of +33% and, finally, in France there is a slight variation of +13%. These price increases may be explained by the shift from coal technologies (without ETS) to CCGT (with ETS) power stations. With the implementation of the ETS, generators prefer to run low emitting plants, like CCGT, and reduce the utilization of the cheaper but more polluting coal stations. In this way, CCGT technologies, together with the pass through of the allowance price, set the electricity price at a higher level than the coal based plants, operating without ETS.

In winter, we have an opposite situation: with the application of the emission system, energy prices become lower. This phenomenon can be explained by the plant merit order. In a perfect competition market, the reference electricity price (the one set at the hub node) is determined by the marginal cost of the last plant that is used to generate electricity. In absence of the emission trading policy, generating companies use both natural gas and oil-based power plants to satisfy the winter consumers' power needs. With the introduction of the carbon market, in the long term perspective, industries reduce their annual demand and, then, the peak load plants (natural gas and oil-based power stations) are no more used to produce electricity. Moreover, those are highly emitting technologies. The ETS obliges generators to change their technology mix in order to achieve their emission benchmarks. Consequently, CCGT power units replace natural gas and oil-based installations and, thus, define the electricity price. CCGT is, in fact, more efficient and its emission factor is about half of the oil one. In this way, electricity becomes cheaper (47.34 €/MWh).

This fact justifies also small consumers' behavior in the peak period: in presence of emission limitations, they increase by almost 1% their electricity consumptions, since prices are a little bit lower in each node. In summer, instead, they require less electricity (-3%) as a consequence of the increase in power prices.

Due to its energy policy, France does not suffer from the introduction of a mandatory cap on emissions. Nuclear is a base-load technology and completely meet the ETS proposals with its zero pollution. On the other hand, Germany, with its high consumption of coal and lignite, is more damaged: this may explain the strong German movement to invest in renewable technologies, namely wind capacity.

According to our input data, there is a consistent decrease in the utilization of coal-based technologies, especially in the off-peak period. Changes in technology mix and increase of the efficiency of the existing plants are part of the objectives that ETS would achieve.

Without the emission constraint, generating companies run the base-load power plants (hydro, nuclear and lignite installations) at their full capacity in each node both in peak and off-peak times. Coal and CCGT plants are partially employed in both periods and, moreover, in winter, natural gas and oil-based technologies are also generating.

With the aim of complying with the emission targets, generators modify their fuel combinations. In summer, base-load technologies are still totally employed. In Germany and in Krimpen, coal production decreases; while, in Gramme, coal installations are no longer used. In Krimpen, the reduction of the coal electricity generation is only of -5%. Merchtem does not modify its level of coal electricity generation. In this situation, the Belgian and the Dutch generating companies react raising the utilization of the less emitting CCGT power plants:

the proportional increases are respectively of +13% and about of +60%. In winter time, as already mentioned, generating companies no longer resort natural gas and oil-based power plants: this represents the main modification. In the ETS context and in accordance with our 2005 data, the utilization of CCGT power plants may be supported, since this technology has a high efficiency rate and a comparatively low emission factor. Their construction costs are more limited than the ones of nuclear plants. All these positive features, joint with low gas prices, encouraged generating companies to invest in CCGT during the 90's. The actual gas price scenario is changed, but CCGT plants are still in construction. The Netherlands and Belgium, which partially base their electricity production on CCGT, may profit from this new market situation and their tendency is to replace coal plants with CCGT in the base-load electricity production.

Under these conditions, generating companies increase their profits by 18% with respect to the case without emissions regulation.

The emission certificate price is about 26.81 €/ton p.a. It means that emissions are still high and new production mechanisms should be introduced.

All these results explain industrial consumers' complaints and suggest that a solution should be found.

III. Average Cost Pricing Aproach

We explore a measure to attenuate the negative consequences of the ETS for industrial customers. The aim is to find solutions whereby industrial consumers might be relieved from the additional burdens caused by the ETS. In fact, we know that electricity intensive users are in a position to finance the construction of power generating units. For this reason, we modify the basic model and we assume that industrial consumers have the control of part of the generating capacity installed in the network. On the other side, small consumers are supplied using the power plant not employed by the industrial segment. This assumption implies that power production units are shared between industrial and small consumers. The split in capacity is endogenous to the problem.

The market segmentation between industrial and small consumers is a direct implication of the technologies splitting. This fact allows the application of different price policies to the two market segments.

Small consumers are still priced at the short-run marginal costs; instead, intensive industrial consumers pay electricity at a price corresponding to the full costs of the power plants dedicated to them. Consequently, we apply the average electricity price that embeds the proportional fixed costs of investments in generating capacity and the variable costs occurring in three different components: fuel, emission and transmission charges. The average costs price mechanism embodies the industrial consumers' idea to finance or support investments and production activities in the electricity sector. This scenario assumes that there exists a unique average cost price paid by all industrial consumers, independently of their locations.

We follow the same structure of the previous section: we, first, present the model with the related variables and, then, we describe the results.

A. Indices and Sets

Indices and sets are the same as before. The only difference is the modeling of the two periods analyzed (summer off-peak and winter peak). They are introduced by a set t, subscripted to the variables depending on time. The apexes *1* and *2* are still used to indicate respectively industrial and retail sectors.

B. Variable and Parameters

Variables and parameters concerning the emission and transmission constraints are not subject to modifications and we omit the list of their variables and parameters. We just introduce the new price formulations and the producers and consumers' changed variables.

Generating Companies' variables

$g_{t,i}^{1,2}$	Hourly MW of power sold at node i in time t to industrial and small consumers;
$gp_{t,f,i,m}^{1,2}$	Hourly MW of power generated in each time t by plant m owned by firm f at node i for large and small consumers;
$G_{f,i,m}^{1,2}$	MW of capacity m owned by firm f at node i dedicated respectively to large and small consumers;
$inj_{t,i}$	Net flow given by the difference between the total amounts of power sold and demanded in each node i and period t;
$\eta_{t,i}^{1,2}$	Dual variables representing the marginal production cost;
$\nu_{t,f,i,m}^{1}$	Dual variables indicating the scarcity rents associated with unit m;
$\sigma_{f,i,m}$	Dual variable matched with the global plant capacity constraint.

Generating Companies' parameters

$G_{f,i,m}$	Nodal installed capacity m owned by firm f
$mc_{f,i,m}$	Marginal costs in €/MWh of unit m owned by firm f at node i in each period.

Consumers' variables

$d_{t,i}^{1,2}$	Hourly MW of power demanded by large and small consumers located at node i in summer and in winter;
$P_{t,i}^{1,2}(d_{t,i}^{1,2})$	Inverted demand function corresponding to the consumers' willingness to pay.

Price variables

p^1	€/MWh average price of electricity;
$p_{t,i}^2$	€/MWh nodal prices of electricity paid by small consumers in each period t;

$phub^2_t$ €/MWh price of electricity set at the hub node;

β_t Marginal industrial electricity price.

Period durations

$hour_t$ Duration in hours of the off-peak an peak periods.

C. Average cost pricing model

We introduce a single annual average price whereby industrial consumers can buy electricity at the same price in any node.

The average cost price formulation makes the mathematical problem more complex, since it can lead to infeasibility due to the presence of fixed costs. The model is composed of two sub-problems: first, we introduce a preliminary model where we simulate a market with capacity splitting and demand segmentation, assuming that both consumer groups are priced at marginal costs. This preliminary step permits to find a starting point for solving the average cost price problem. Then, we run the model with the average price. The optimization problem for small consumers is the same in both cases; the main variation is for industrial customers. For the sake of simplicity, we present only the model where large consumers are priced at the average cost. The reader should keep in mind that the preliminary model is essentially identical to the problem presented below: he has just to replace the average cost price with a marginal cost based price.

Again, we start with the analysis of the generating companies' maximization problem; then we present the consumers' model and, finally, we describe the global emission and transmission constraints.

Generating companies f sell electricity to both consumer sectors with the intent to maximize their annual profits. As explained, they apply the marginal cost price to the retail market and the average cost price to industries. The plant capacity limits and the generation balances are the constraints that restrict the electricity production activities. The problem is formulated as follows:

$$\begin{aligned}\max \quad & p^1 \cdot \sum_{t,i} g^1_{t,i} \cdot hour_t + \sum_i p^2_{t,i} \cdot g^2_{t,i} \cdot hour_t \\ & - \sum_{t,i,m} mc_{f,i,m} \cdot gp^1_{t,f,i,m} \cdot hour_t - \sum_{t,i,m} mc_{f,i,m} \cdot gp^2_{t,f,i,m} \cdot hour_t \\ & + \lambda \cdot (NAP_f - (\sum_{t,i,m} em_m \cdot gp^1_{t,f,i,m} \cdot hour_t + \sum_{t,i,m} em_m \cdot gp^2_{t,f,i,m} \cdot hour_t)) \\ & - \sum_{t,l,i} PTDF_{l,i} \cdot inj_{t,i} \cdot (\mu^+_{t,i} - \mu^-_{t,i}) \cdot hour_t \end{aligned} \tag{20}$$

Subject to:

$$inj_{t,i} = g^1_{t,i} + g^2_{t,i} - d^1_{t,i} - d^2_{t,i} \tag{21}$$

$$\sum_{f,m} gp^1_{t,f,i,m} - g^1_{t,i} = 0 \qquad (\eta^1_{t,i}) \tag{22}$$

$$\sum_{f,m} gp^2_{t,f,i,m} - g^2_{t,i} = 0 \qquad (\eta^2_{t,i}) \tag{23}$$

$$G^1_{f,i,m} - gp^1_{t,f,i,m} \geq 0 \qquad (\nu^1_{t,f,i,m}) \tag{24}$$

$$G^2_{f,i,m} - gp^2_{t,f,i,m} \geq 0 \qquad (\nu^2_{t,f,i,m}) \tag{25}$$

$$G_{f,i,m} - G^1_{f,i,m} - G^2_{f,i,m} \geq 0 \qquad (\sigma_{f,i,m}) \tag{26}$$

The objective function (20) includes production expenditures (represented by the fuel costs), emission opportunity charges and the congestions costs. Condition (21) states the equality between the total amount of power injected and withdrawn at each node. Nodal electricity balances (22) and (23) between power produced and sold are again required. The associated dual variables quantify the marginal production costs. Inequalities (24) and (25) are meant to represent the endogenous definition of the capacity split between industries and retail sector. The value of the scarcity rents coming out from these two constraints are companies' additional "gains". Their amount is influenced by electricity prices and companies' marginal technology costs. Condition (26) states that the sum of plant capacities given to small and large consumers should not exceed the total fixed capacity. The dual variable matched with this constraint states an indirect equality between the scarcity dual rents associated with inequalities (24) and (25).

All conditions presented hold both in peak and off-peak periods.

The main contribution of our case study is the implementation of the average cost pricing policy. In line with its economic interpretation, the average cost price is defined as stated below:

$$\begin{aligned} p^1 = & \frac{\sum_t hour_t (\sum_{f,i,m} g^1_{t,f,i,m} \cdot (mc_{f,i,m} + em_m \cdot \lambda))}{\sum_{t,i} d^1_{t,i} \cdot hour_t} \\ & + \frac{\sum_t hour_t (\sum_{l,i} PTDF_{l,i} \cdot inj_{t,i} \cdot (-\mu^+_{t,l} + \mu^-_{t,l}))}{\sum_{t,i} d^1_{t,i} \cdot hour_t} + \frac{\sum_{f,i,m} FC_{m,i} \cdot G^1_{f,i,m}}{\sum_{t,i} d^1_{t,i} \cdot hour_t} \end{aligned}$$

where FC are the annual fixed charges depending on technologies m and node i. The fixed costs are computed on the basis of amortized overnight costs method. This accounts for the construction costs depending on the technologies and countries considered. For instance, the investment costs for a new nuclear plant in France are lower than in Germany or in the Netherlands. Moreover, each technology has its own life. Variable costs faced by generating companies are included in the average cost price.

On the other side, all consumers desire to maximize their surplus in each period studied as indicated in (27) and (28). They introduce the surplus objective function respectively for industries and small consumers. Obviously, the quantities of electricity required must be positive.

$$\max \int_0^{d^1_{t,i}} P^1_{t,i}(\varepsilon) \cdot d\varepsilon \cdot hour_t - p^1 \cdot d^1_{t,i} \cdot hour_t \tag{27}$$

$$\max \int_0^{d^2_{t,i}} P^2_{t,i}(\varepsilon) \cdot d\varepsilon \cdot hour_t - p^2_{t,i} \cdot d^2_{t,i} \cdot hour_t \tag{28}$$

The market balances (29) and (30) are essential for guaranteeing the efficiency and the stability of the whole system: in each hour and for each market segment, the total amount of electricity supplied must equal customers' demand.

$$\sum_i d^1_{t,i} - \sum_i g^1_{t,i} = 0 \qquad (\beta_t) \tag{29}$$

$$\sum_i d^2_{t,i} - \sum_i g^2_{t,i} = 0 \qquad (phub^2_t) \tag{30}$$

The small consumers' balance equation is paired with the hub price. The hub shadow price, in addition with the congestion costs, is then used to define the small consumers' marginal electricity prices at each node as indicated in (31).

$$p^2_{t,i} = phub^2_t + \sum_m (-\mu^+_{t,l} + \mu^-_{t,l}) \cdot PTDF_{l,i} \tag{31}$$

This price scheme relies on the perfect competition assumption with which we model the small consumers' segment. The dual variable β_t represents the marginal dual power price that industries should pay. This variable is introduced in order to model the plant merit order. Making a parallelism with the small customers' problem, one can easily see that β_t corresponds exactly to the hub price. For this reason, in the preliminary model, that for sake of simplicity we don't present, we use this variable to define the electricity price for industrial consumers.

Finally, inequalities (32), (33) and (34) state the global market restrictions. The first two are the transmission constraints, while the last one regulates the emission trading market. They maintain the roles already described in the reference model.

$$Linecap_l - \sum_i PTDF_{l,i}(g^1_{t,i} + g^2_{t,i} - d^1_{t,i} - d^2_{t,i}) \geq 0 \quad (\mu^+_{t,l}) \tag{32}$$

$$Linecap_l + \sum_i PTDF_{l,i}(g^1_{t,i} + g^2_{t,i} - d^1_{t,i} - d^2_{t,i}) \geq 0 \quad (\mu^-_{t,l}) \tag{33}$$

$$E - (\sum_{t,f,i,m} gp^1_{t,f,i,m} \cdot em_m \cdot hour_t + \sum_{t,f,i,m} gp^2_{t,f,i,m} \cdot em_m \cdot hour_t) \geq 0 \ (\lambda) \tag{34}$$

D. Results interpretation

As analyzed in the previous section, industrial consumers' complaints are justified: the ETS increases the European cost of electricity.

The proposal of the application of the average cost pricing approach could be a solution to large customers' requests. According to our input data, the average price got is 37.35 €/MWh, of which the fixed costs are the main component. This price is, in average, lower than the ones obtained in the reference case: this explains the reason why large consumers increase their electricity consumption.

Apart for France, in all other nodes, industrial consumers require more energy than before. The increase is particularly huge in all Dutch nodes (+29% and +30%) and in Merchtem (+30%), while in Gramme is only of +1%. Germany assumes an intermediate position with +23%. Totally, the hourly rise in large consumers' demand is about +7% and their global benefit becomes higher than before by 8%. French industrial consumers, instead, cannot profit from the average cost price mechanism. In fact, they face higher electricity price with respect to the reference scenario and then they react reducing their electricity consumption by -21%.

If large consumers can take benefit from this policy; on the other side, small consumers meet higher electricity prices both in peak and off-peak periods. This is partially caused by the split in capacity. The great part of the base-load technologies (hydro (72%) and nuclear (53%)) installed in the network is dedicated to large consumers, while the more expensive coal, CCGT, natural gas and oil-based power plants are mainly used to supply small consumers. The latter technology sets small electricity price, since they are assumed to operate in a perfectly competitive market. Those power stations are fully run in the winter peak period in order to cover small consumers' consumption. Since such technologies are highly polluting, the emission certificate price increases: it is 32.13 €/ton p.a.

Raises in retail sector' prices are more consistent in winter (from +6% in France up to +77% in Merchtem), while they are more limited in summer (between +6% and +12%)[7]. As a result, their hourly demand decreases both in peak and off-peak times. Reductions are between -1.1% (in Germany) and -0.6% (in Maastricht) in summer, while in winter they are greater: from -9.3% (in Merchtem) up to -0.7% (in France). This negative tendency is also stressed by the cut of about -4% in their global surplus, with respect to the reference scenario.

French industrial consumers face the same situation. They cannot take advantages of the average cost pricing scheme, since now everyone can have access to their nuclear capacity. France, in fact, plays an important role in this market segment: it exports a huge amount of electricity that is used to cover large consumers' electricity needs in bordering countries. It happens both in peak and off-peak periods. This allows meeting the industrial market energy balance, but it also affects the French industries' competitive positions on their output markets.

IV. Conclusions

The situation described represents the initial request launched by European industrial companies: having access to cheap and environmental-friendly nuclear capacity. The application of these special contracts based on the average cost pricing mechanism seems to be useful to accommodate industrial firms: their electricity price becomes lower and their surplus increases.

Nevertheless there are questions still opened: the high emission price stresses market inefficiencies in electricity production. It means that investments in renewable power technologies, development of the efficiency of existing electricity units and replacing of the old ones are very much needed. By following these strategies, European firms could achieve their emission benchmarks without damaging the retail consumer side.

[7] The French summer price is an exception: it is set at 4.5 €/MWh, the marginal cost of nuclear capacity.

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