CEJOR (2009) 17:181–217
DOI 10.1007/s10100-008-0083-x

ORIGINAL PAPER

Evaluating the impact of average cost based contracts on the industrial sector in the European emission trading scheme

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Published online: 9 January 2009

Abstract The inception of the emission trading scheme in Europe has contributed to power price increases. Energy intensive industries have reacted by arguing that this may affect their competitiveness and will induce them to leave Europe. Taking up a proposal of these industrial sectors, we explore the possible application of special contracts, where electricity is sold at average generation cost to mitigate the impact of CO_2 cost on power prices. The model supposes fixed generation capacities. We first consider a reference model representing a perfectly competitive market where all consumers (industries and the rest of the market) are price-takers and buy electricity at short-run marginal cost. We then change the market design by assuming that energy intensive industries pay power either at a regional or at a zonal average cost price. The analysis is conducted with simulation models applied to the Central Western European power market. The models are implemented in GAMS/PATH.

Keywords Emission trading scheme (ETS) · Carbon leakage · Average cost based contracts · Complementarity conditions · Central Western European market

This work has been financially supported by the Chair Lhoist Berghmans in Environmental Economics and Management and by the Italian project PRIN 2006, Generalized monotonicity: models and applications, whose national responsible is Prof. Elisabetta Allevi.

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Mathematics Subject Classification (2000) 46N10 · 90C33 · 91B76

1 Introduction

The European Union introduced its emission trading scheme (EU-ETS) in January 2005 with the view of curbing CO_2 emissions and hence contributing to mitigate climate change. The degradation of the competitiveness of part of the European electricity intensive industries (EIIs) is progressively emerging as an unintended but possible consequence of this combination of the EU-ETS with the restructuring of the electricity sector. The negative impact of the ETS on EIIs is twofold: industries need not only abate emissions (direct impact); they also face a higher electricity price (indirect impact). This second, apparently unexpected, effect results from the power sector passing CO_2 (opportunity) costs into electricity prices in a competitive market.[1] EIIs can adapt to these cost increases by accepting lower profits or increasing their product prices. They explain that this endangers their competitiveness on international markets. Some studies (e.g., Demailly and Quirion 2006; McKinsey and Ecofys 2006; Reinaud 2005) show that the industrial sectors' exposure to the EU-ETS depends on (1) the industry's ability to pass the extra carbon cost to consumers, (2) the international trade openness, (3) the energy intensity and the possibility to abate carbon and, last, (4) the allowance allocation method.[2] These factors vary with the industrial sector considered. EIIs further argue that this cost increase will eventually force some of them to move part of their production activities to extra-Community countries where emission policies are less restrictive. This may entail a serious loss of welfare for the European countries with no global environmental gain. CO_2 emissions will simply be displaced or more likely increased because the relocated EIIs' plants will connect to less efficient electricity systems. This phenomenon is known as carbon leakage.[3]

EIIs have responded to this challenge by various proposals: one of them is to change the mechanism adopted to price electricity. Specifically, they ask for long-term contracts whereby they can procure electricity at average instead of marginal cost. This pricing principle underlies the formation of the Exeltium consortium in France where a number of electro-intensive industries managed to conclude long term contracts with generators at a national cost based price. Long term competitiveness and price stability are the arguments invoked to justify these contracts. The underlying principle of these contracts is for generators to reserve part of their power plants for EIIs and apply to them a price computed as the average capacity, fuel and emission costs of these dedicated units.

In this paper, we test the extent to which these special contracts would heal the ETS burdens on industries and hence reduce the leakage effect. We illustrate this issue by

[1] This is in addition to the higher fuel prices, namely coal and gas.

[2] The allowance allocation method and the amount of distributed allowances affect operational costs. For instance, free allowances lessen the cost imposed by the ETS system but may also create inadequate economic incentives.

[3] Carbon leakage strongly depends on plants re-location. It measures the compensation of an industry's greenhouse gas reduction by an increase in the same industry's emissions in regions without carbon constraint.

the means of small market simulations applied to a simplified electricity network of the Central Western Europe (CWE) represented by France, Germany, Belgium and the Netherlands. With the aim of investigating the implications of the carbon market on electricity prices and demand, we first simulate a perfectly competitive market where all consumers (EIIs and the rest of the market) are price-takers and are assumed to pay an identical electricity price equal to marginal cost. This constitutes our reference case. We then model both a regional and a zonal average cost pricing systems. These scenarios imply segmenting the market and sharing the existing generation capacity between the two consumer groups in the sense that part of the generation capacity is fully dedicated to EIIs.

We find that the global effectiveness of average cost based prices on industrial consumers is real but their impact differs depending on their location and the price arrangement (regional or zonal) applied. Moreover, the technology mix used to produce electricity plays a decisive role in the forming of industrial power prices.

The paper is organized as follows. Section 2 gives a brief overview of the system used in the simulations. The perfect competition models that serve as reference for the analysis are briefly presented in Sect. 3, and their results are reported in Sect. 4. A short discussion of the two average cost pricing models is given in Sect. 5 with results provided in Sect. 6. We summarize the discussion with a welfare analysis in Sect. 7 and present sensitivity results that show the robustness of our findings in Sect. 8. Conclusion terminates the paper. The technical descriptions of the models are reported in appendices.

2 Input data and assumptions

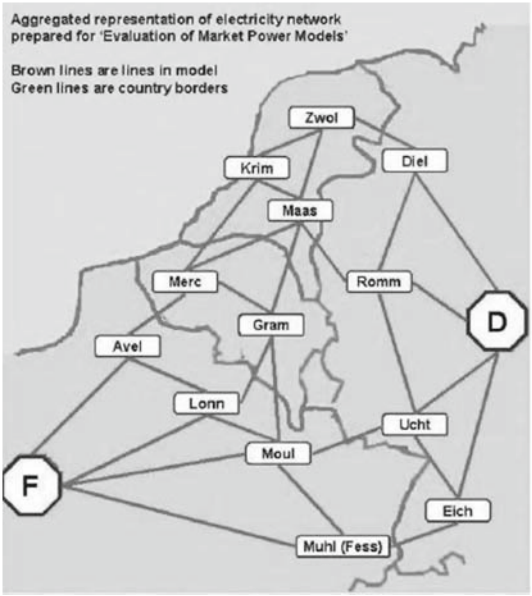
We conduct the analysis on a stylized representation of the electricity market of CWE. Electricity is provided by eight generators[4] and a fringe, which assembles the remaining small generators. We adopt a standard technological representation of the power sector. Generators operate eight different technologies[5] characterized by available capacities, efficiencies, emission factors and fuel costs (see Tables 14, 15 in Appendix E). Together with the CO_2 allowance price, this information specifies the plants' marginal costs which in turn determine their (endogenously constructed) merit order.

The power system covers 15 zones located in four countries (see Fig. 1). They are connected by 28 flowgates with limited capacity.[6] The grid is modeled by using a Power Transfer Distribution Factors matrix (PTDF) provided by ECN (ECN 2005; Fig. 1 for the values). Supply and demand are located at seven zones: two in Belgium (Merchtem and Gramme), three in the Netherlands (Krimpen, Maastricht and Zwolle), one in Germany ("D") and, finally, one in France ("F"). The remaining German and

4 E.ON Energie AG, Electrabel SA, Electricité de France, ENBW Energieversorgung Baden-Württemberg, Essent Energie Productie BV, Nuon, RWE Energie AG, Vattenfall Europe AG.

5 Hydro (running-of-river plants), renewable, nuclear, lignite, coal, CCGT, other-gas and oil-based plants.

6 Consult the Harvard Electricity Policy Group (HEPG) website, section "Research Library" subsection "Flowgate Models, Transmission (Including Direct Access) and Transmission Rights" for an extensive bibliography on the subject; see also Boucher and Smeers (2001), for an attempt to present a unified view of these matters.



Flowgate	Reactance	Max Capacity [MW]
AVEL_LONN	22,2	2762
D_DIEL	45,9	20000
D_EICH	45,9	20000
D_ROMM	45,9	20000
D_UCHT	45,9	20000
DIEL_ROMM	69,2	1842
DIEL_ZWOL	12,2	2971
EICH_UCHT	41,3	3329
F_AVEL	45,9	20000
F_LONN	45,9	20000
F_MOUL	45,9	20000
F_MUHL	45,9	20000
GRAM_LONN	45,2	1207
GRAM_MOUL	156,5	267
KRIM_MERC	34,2	936
LONN_MOUL	27,1	1842
MAAS_GRAM	41,8	641
MAAS_KRIM	29,1	1842
MAAS_MERC	61,0	641
MERC_AVEL	55,4	898
MERC_GRAM	31,1	1842
MOUL_MUHL	38,2	3329
MUHL_EICH	11,5	1282
ROMM_MAAS	28,3	896
ROMM_UCHT	43,0	1842
UCHT_MOUL	25,4	1326
ZWOL_KRIM	33,1	1842
ZWOL_MAAS	50,0	1842

Fig. 1 Central Western European market and network line capacities

French zones are passive and are only used to transfer electricity. We justify the use of a zonal flowgate model on two grounds: first this model is publicly documented; second European Transmission System Operators (TSOs) plan to effectively move from a transmission capacity to a flowgate organization of transmission in CWE.

The time horizon is 1 year, subdivided in two periods, winter and summer, measured in hours per year, with different durations. The summer lasts 7 months (5,136 h) and the winter the remaining 5 months (3,624 h). We fully acknowledge that this is not sufficient to get a good representation of the system. However, it suffices to illustrate the phenomenon at work while keeping the model simple. This simplification amounts to modelling the base-load electricity demand of consumers. Following Stoft 2002, we conduct the whole discussion on an hourly basis. This allows one to express capacities in MWh (instead of MW).

We distinguish two consumer groups: EIIs and the rest of the market (N-EIIs) representing small consumers of electricity, households and the tertiary sector. Due to the absence of information, we model both EIIs and N-EIIs by a linear demand function. A reduction of industrial demand is interpreted as a relocation of production activities and consequently measures the leakage effect. Demand functions differ by zone. Moreover, we suppose a constant industrial consumption level over the year while N-EIIs demand more electricity in winter than in summer (see Table 13 in Appendix E). As already indicated, we limit ourselves to two seasons assumed to respectively represent the summer and the winter periods. Demand curves are calibrated through a reference point and an elasticity at that point. A wholesale reference price of 40 €/MWh is applied to N-EIIs and EIIs' demand functions in both periods. Since our priority consists in analyzing consumers' reactions to the introduction of the EU-ETS, we model long-run demand function. N-EIIs are expected to behave less flexible and we therefore assume that their demand elasticity is -0.1 in the reference point. Contrarily, we set EIIs' demand elasticity at -1 in order to account for their ability to leave Europe in case of too high electricity prices.[7]

We adopt an emission cap of 397 Mio ton p.a. We assume that the allowance market is restricted to the power sector and do not model allowance trade among industries. This assumption restricts the analysis to the sole indirect ETS impact (the increased electricity price), which has been most criticized by EIIs. We offer a formal extension of the current model that embeds the whole set of sectors covered by the EU-ETS in two follow up papers (Oggioni and Smeers 2008a,b). Given this restriction, the emission cap corresponds exactly to the sum of the NAPs of the generators included in the simulation tests. It defines the amount of allowances initially allocated to the power market. A detailed list of the allowance allocations by country and generator is reported in Table 16 in Appendix E. Finally, market simulations are calibrated with data updated to 2005.

3 The reference models

The reference models simulate a perfectly competitive market involving three types of agents: generators, consumers (N-EIIs and EIIs) and a TSO. A first model describes the market without ETS; a second model includes the ETS. We here give a verbal presentation of these models; Appendix B takes stock of this description to derive the complementarity formulation of the ETS reference model (the non ETS model is readily obtained from the ETS model by dropping the carbon market).

All agents are price-takers and maximize their surpluses. Generators maximize profits by selling at zonal price to both EIIs and N-EIIs. Their expenses include fuel and emission (opportunity) costs. Generation activity is subject to technological constraints, which ensure that the quantity of electricity produced by each technology is limited by the production capacity of the corresponding power plants.

Consumers maximize their surplus. As already explained, we assume for the sake of realism that EIIs operate at constant level throughout the year and hence have a constant electricity consumption.

As mentioned, we adopt a flowgate representation of the grid in terms of PTDF and capacities. Germany is the hub.[8] The TSO maximizes the merchandising surplus[9] accruing from transmission operations. This is equivalent to buying and selling electricity at zonal prices so as to maximize profit within the transmission capacities allowed by the grid. This maximization also gives the price of transmission services at each

[7] Since there is almost complete lack of information of demand response of industrial consumers, we took this -1 value from a Newbery's paper (Newbery 2003).

[8] The hub can be considered as a virtual market where all electricity asks and bids converge and clear by setting a marginal floor electricity price.

[9] Consult the HEPG website, section "Research Library" subsection "Flowgate Models, Transmission (including direct access) and Transmission Rights" for an extensive bibliography on the subject; see also Boucher and Smeers (2001).

Table 1 EIIs' hourly demand without and with the EU-ETS

MWh	NETS_R	ETS_R	Variations (%)
Germany	32,214	25,095	−22
France	25,015	24,910	−0.4
Merchtem	3,573	3,538	−1
Gramme	2,029	1,963	−3
Krimpen	2,722	2,603	−4
Maastricht	942	889	−6
Zwolle	1,800	1,615	−10
Total	68,294	60,613	−11

congested flowgate. The transmission market is thus a zonal system operating under perfect competition.

There is a single energy market for both the EIIs and the N-EIIs. This market clears at the hub. Zonal prices are obtained from the hub by adding contributions from the transmission market that reflect the use and the price of the congested flowgates obtained from the maximization of the TSO merchandising surplus.

Last, we represent the allowance market through an emission balance equation and introduce a market clearing price for that market. The market clearing price in the allowance market is thus an output of the model.

4 Results of the reference model

We assess the long-run impacts of the EU-ETS on EIIs by comparing the results of the reference model with and without the allowance market.

4.1 Electricity consumption and relocation effects

Table 1 shows hourly industrial electricity consumption before (NETS_R) and after (ETS_R) the introduction of the ETS. EIIs decrease their electricity consumption by 11% after the inception of the EU-ETS.[10] This is accompanied by a cut of almost 22% in their annual surplus (see Sect. 7). This consumption drop is interpreted in this paper as a relocation of EIIs' activities outside of the EU. This relocation is geographically quite differentiated as Table 1 shows. The analysis of the electricity prices explains this differentiation.

4.2 Transmission and price formation

The combination of the ETS and of the organization of transmission modifies seasonal electricity prices. Tables 2 and 3 respectively report summer and winter prices.

[10] This fall in their electricity consumption is significant, but it is really driven by our assumptions. The reader should indeed keep in mind that we model industries' long run behavior and hence assume a demand elasticity of −1. This model assumption is selected to fit the threat, exposed by large consumers, of relocating their production capacities.

Table 2 EIIs and N-EIIs' summer electricity prices in €/MWh without and with the EU-ETS

Summer			
€/MWh	NETS_R	ETS_R	Variations (%)
Germany	21.62	44.94	108
France	4.50	5.07	13
Merchtem	36.35	46.91	29
Gramme	19.09	27.79	46
Krimpen	36.35	46.91	29
Maastricht	36.35	46.91	29
Zwolle	32.15	46.07	43

Table 3 EIIs and N-EIIs' winter electricity prices in €/MWh without and with the EU-ETS

Winter			
€/MWh	NETS_R	ETS_R	Variations (%)
Germany	51.48	47.36	−8
France	47.48	47.36	−0.3
Merchtem	57.26	47.36	−17
Gramme	53.22	47.36	−11
Krimpen	54.92	47.36	−14
Maastricht	54.03	47.36	−12
Zwolle	53.66	47.36	−12

Recall that, whatever the season, prices are identical for EIIs and N-EIIs in perfect competition models.

Some flowgates are congested in summer. This is the case for lines between France and Germany and between France and Belgium. The interconnector between the Belgian zone Merchtem and the Dutch zone Krimpen is congested as well as between Gramme and Maastricht. The direction of the flows reveals that France exports both to Germany and Belgium, which, in turn, supplies the Netherlands. Since a great part of the nuclear electricity generated in France is exported, the congestion of the lines, combined with the marginal cost pricing implicit in this model, reduces the French power price to a level close to its marginal operating cost (5.07 €/MWh). This happens even though the price of the neighboring countries is higher. The congestion cost makes the difference.

The situation is different in winter. Consumption is higher, which requires additional generation in each zone and hence reduces the amount of CO_2 free and cheap nuclear electricity available for export. One line connecting France with Belgium remains congested in winter in the NETS_R scenario, which, as the theory of nodal transmission (here applied to a zonal representation of the grid) shows, makes electricity prices different in all zones. Consumers globally reduce their electricity demand in the ETS_R case, decreasing the amount of power exported in winter, and hence avoiding the congestion of the grid. All consumers therefore pay the hub price in the

ETS_R version of the model because the transmission grid is no longer congested. It is important to recognize the real nature of the phenomenon: the EU-ETS decreases congestion because it reduces EIIs' consumption.

Table 2 shows that the EU-ETS increases electricity prices in summer. The merit order of the plants explains this non intuitive result. Recall that, in perfect competition and in the absence of transmission constraints, the most expensive plant sets the electricity price at the hub. In the NETS_R scenario, the price at the hub (Germany) is 21.62 €/MWh which corresponds exactly to the fuel cost of a coal plant (see Table 15 in Appendix E). With the implementation of the EU-ETS, generators switch to low emitting technologies, like CCGT, and reduce the utilization of more polluting ones (namely coal). Notwithstanding this technology switch,[11] coal plants again set the electricity price at the hub. In the ETS_R, price in Germany amounts to 44.94 €/MWh which corresponds exactly to coal fuel cost (21.62 € /MWh) increased by the respective carbon opportunity cost (23.32 €/MWh.[12]) The pass through of the allowance price explains why, in summer, power is more expensive in the ETS_R scenario than in the NETS_R case. Hydro, renewable and nuclear capacities are saturated in both periods.

We observe a reverse behavior in winter where the ETS reduces energy prices. The combination of the change of plant merit order and the reduction of electricity consumption explains this outcome. The EU-ETS obliges generators to modify their fuel mix and to switch to lower emitting plants in order to achieve their emission target. For all these reasons, CCGT power units determine the winter electricity price (47.36 €/MWh), by replacing the old natural gas and oil based installations used in the NETS_R case. This makes power cheaper than before. The requirement that industrial consumption remains constant throughout the year explains that demand and price can simultaneously decrease. This is confirmed by comparing with the more usual N-EIIs' behaviour: in winter and in presence of emission limitations, they increase electricity consumption by 1% , since prices are a little bit lower in each zone. In summer, instead, they lessen their energy utilization (almost −3%) as a consequence of the raised power prices. Table 3 reports the associated price relative changes.

The effect of the EU-ETS on prices is thus twofold: first, it adds a carbon component to summer prices; second, it removes expensive and inefficient units in winter. These two effects interact with the constant (endogenous) demand level in the industrial sectors.

4.3 The carbon market

The allowance price amounts to 24.44 €/ton in this EU-ETS perfect competition model. This positive value signals a tight emission cap.

[11] In summer the contribution of clean technologies in the ETS_R raises by 5% with respect to the NETS_R level. This is also followed by an increase of 1% of the utilization of CCGT. The proportion of coal electricity production falls by 6% after the inception of the EU-ETS.

[12] The carbon opportunity cost of a coal plant is computed by multiplying the allowance price of the ETS_R scenario (24.44 €/ton) by the emission factor of a coal plant (0.9542 ton/MWh according to our input data).

The ETS globally reduces carbon emission by -14% from an annual level of about 464 to 397 Mio ton. This is the CO_2 emission ceiling imposed on the power sector in the model. Parallel to the global reduction in electricity consumption, one observes a decreasing emission level in almost all the zones of CWE. The Dutch locations Maastricht and Zwolle are two exceptions. The global pollution level increases with respect to the NETS_R case in Maastricht. Generators, in fact, raise the operation of their CCGT plants in order to reduce their electricity imports, in response to the summer congestion of the line between Maastricht and the Belgian zone Gramme. Emissions remain constant in Zwolle, since both the capacity and the fuel mix used to produce energy do not change with respect to the unconstrained carbon case.

Finally, assuming the grandfathering of allowances, generators' profit globally increases by 16% with respect to the NETS_R case (see Sect. 7). All this fits well with the problem of competitiveness and demand destruction argued by EIIs. We now explore the remedy that they propose.

5 Average cost pricing mechanism

The above results are in line with the thesis that the EU-ETS increases electricity prices and induces a corresponding reduction of industrial electricity consumption (that we here assimilate to carbon leakage). We explore a remedy that consists in granting different electricity purchase conditions to EIIs: specifically, we assume that EIIs procure electricity through special contracts reflecting the full cost of dedicated generation capacities.

Recall first that the market is separated in two segments respectively representing the EIIs and the N-EIIs. In order to model the EIIs' special procurement conditions, we now also split the generation system into two subsystems each allocated to one of these market segments. This subdivision of generation capacities is endogenously determined by the model as the final EIIs' consumption is also endogenous. The principle driving the allocation is to equalize the marginal value of the capacities allocated to the two segments as this implicitly amounts to maximizing the total capacity value. The allocation is thus as economically efficient as it can be under the market segmentation constraint. Given this market segmentation, we assume that N-EIIs still pay electricity at short-run marginal costs. In contrast, EIIs pay the average full cost of the power plants reserved for them. We consider two particular views of these cost based contracts.

Following an arrangement currently in force in France, we first represent a case where EIIs can purchase electricity at a regional average cost price through a power purchase consortium (ETS_RAC model or ETS Regional Average Cost). The arrangement probably implies extended congestion costs accross zones that need to be charged to the users of the grid. In this scenario, the final electricity price faced by EIIs includes both the average production and emission costs as well as the average congestion cost paid to the TSO.

We also model a second case, where EIIs buy electricity from local generators. This leads to a Zonal Average Cost based price system (ETS_ZAC model). Industries are here relieved from paying congestion costs, but they are restricted to purchasing

Table 4 Regional average cost price (RAC)

Cost components	€/MWh
Fuel	10.64
Transmission	2.74
Emission	7.32
Capacity	17.39
RAC	38.10

power from generators in the zone. This makes electricity prices strictly dependent on the zonal fuel mix. Section 6 describes the results of the average cost models.

Both average cost pricing mechanisms adopt the same representation of perfectly competitive transmission and emission markets as the reference model. Moreover, the main structure and the constraints of the average cost based problems are quite similar to the those of the reference case. Generators maximize their annual profits from selling electricity to N-EIIs and minimize the cost of producing and delivering electricity to EIIs.[13] They do so while accounting for the standard production and capacity constraints. Consumers still maximize their surpluses. The mixed complementarity formulations of the regional and the zonal average cost pricing models are presented respectively in Appendices C.1 and C.2. Finally, Appendix D gives information about some computational issues arising with average cost models.

6 Results of the average cost pricing models

The regional and zonal average cost based contracts have different impacts on EIIs. These are also influenced by the energy policy of the zones.

6.1 EIIs' electricity prices

6.1.1 Regional average cost price

The regional average cost price amounts to 38.10 €/MWh as indicated in Table 4. Fixed costs contribute for the largest part, followed by the fuel and emission charges. EIIs tend to congest the network by importing from France and, in average, pay 2.74 €/MWh to the TSO. Note that this is an average transmission cost, much lower than the marginal transmission cost. It amounts to subsidizing exports.

The endogenous allocation of the installed capacity to the EIIs and N-EIIs explains the significant contribution of the capacity cost to the regional electricity price. A great part of the total base-load capacities [hydro (60%), nuclear (52%) and lignite (62%] is now reserved for EIIs. Also 71% of the available renewable capacity is dedicated to them. These technology are characterized by high capacity charges and low variable

[13] The application of average cost prices does not lead to a profit maximization.

Table 5 Zonal average cost price (ZAC)

€/MWh	Fuel	Emission	Capacity	ZAC
Germany	11.59	17.59	14.52	43.70
France	4.50	0.00	12.89	17.39
Merchtem	25.76	22.77	11.25	59.79
Gramme	9.03	1.75	13.01	23.79
Krimpen	25.58	15.56	12.11	53.25
Maastricht	36.35	12.19	8.53	57.06
Zwolle	36.35	12.19	8.53	57.06

costs. Finally, 17, 3 and 14% of respectively lignite, coal and CCGT existing capacities are dedicated to industries.

More specifically, generators in France and Gramme use only clean technologies (namely hydro, renewable and nuclear) to supply EIIs. As expected, France plays an important role in this market segment, since its power exports are significant. In fact, the nuclear capacity reserved by French generators to EIIs is larger than the French EIIs' demand.[14] French EIIs therefore share dedicated nuclear capacity with the industry of other countries. This is obviously detrimental for French EIIs which now have to buy electricity at a higher price because of exports.

Emission costs raise from the utilization of lignite, coal and CCGT plants which also affects the average fuel charges. In this case, the allowance price is 28.48 €/ton. As for transmission, one notes that EIIs are no longer charged the marginal allowance cost but the lower average cost. This is what the industry required.

6.1.2 Zonal average cost price

Table 5 lists the zonal average cost prices. These are affected by the generation mix used to produce electricity in the different zones. French EIIs' electricity price is the lowest. It amounts to 17.39 €/MWh, of which 4.50 €/MWh is the average fuel cost and 12.89 €/MWh represents the capacity charge. French generators cover national industrial demand with the sole nuclear plants.[15] Because nuclear is CO_2 free, the French zonal average cost price does not include any allowance cost. Fuel and capacity charges are exactly those reported for nuclear plants in Tables 15 and 17 of Appendix E. In Gramme, industries are mainly supplied by hydro, renewable and nuclear. Moreover, 373 MWh of CCGT and 170 MWh old natural gas plants (which are not run) are committed to EIIs. Hydro and renewable reduce the fuel average costs. Emissions are only generated by CCGT plants and lead to an average contribution of 1.75 €/MWh. In the other Belgian zone Merchtem, EIIs face the highest zonal average cost price of the market. Generators use the whole zonal coal capacity, 1,564 MWh, and 612 MWh of the CCGT to cover EIIs' electricity demand. All the clean power stations

[14] Globally, the electricity production for EIIs amounts to 24,844 MWh, of which 19,408 MWh are locally consumed. The other 5,436 MWh are exported. Note that the nuclear capacity dedicated to EIIs is 21,662 MWh.

[15] Precisely 29,002 MWh corresponding to the 64% of the nuclear capacity installed in France.

Table 6 EIIs' hourly electricity demand under different pricing scenarios

MWh	NETS_R	ETS_R	ETS_RAC	ETS_ZAC
Germany	32,214	25,095	31,065	26,913
France	25,015	24,910	19,408	29,002
Merchtem	3,573	3,538	4,511	2,176
Gramme	2,029	1,963	1,939	2,601
Krimpen	2,722	2,603	3,319	2,119
Maastricht	942	889	1,133	620
Zwolle	1,800	1,615	2,033	1,113
Total	68,294	60,613	63,408	64,543

(namely hydro, renewable and nuclear) are dedicated to N-EIIs. This implies quite high emission and fuel costs that added to the capacity charges lead to an average price of 59.79 €/MWh. This behaviour is unexpected and hard to justify on standard economic reasoning. It is maybe explained on grounds of nonconvexity implied by the average cost pricing scheme. The analysis of this question goes beyond the scope of this paper (for a brief discussion see Appendix D). Dutch EIIs in Maastricht and in Zwolle face an identical average cost price of 57.06 €/MWh. This is easily justified on the ground that both zones are only supplied by CCGT.[16] In Krimpen, the set of the technologies given to industries is composed of renewable, nuclear, coal and CCGT. This mix gives an average price of 53.25 €/MWh as indicated in Table 5. In this case, fuel charges are lower than in the other two Dutch zones, but emission contribution is higher because of coal. Finally, German EIIs are mostly supplied by lignite based technologies, accompanied by nuclear, coal, hydro and renewable. Because of the high lignite contribution, emission charges have the major weight in their prices. In this model, the allowance price amounts to 28.21 €/ton.

6.2 EIIs' electricity consumption and relocation effects

Table 6 compares EIIs' hourly electricity demand under different pricing scenarios.

6.2.1 EIIs' demand in the regional average cost scenario

The regional average cost pricing system globally recovers 5% of the EIIs' power demand with respect to the ETS_R outcome (or 36% of the demand lost by the introduction of the EU-ETS[17]). This is the intended objective of the policy.

[16] 57.06 €/MWh corresponds exactly to the sum of the average fuel, emission and capacity charge of a nuclear plant. Moreover, average emission costs are identical since are simply computed by multiplying the CCGT emission factor (0.432 ton/MWh) by the allowance price (28.21 €/ton).

[17] The demand loss due to the EU-ETS is the difference between EIIs' hourly consumption in the NETS_R and the ETS_R scenarios. The demand recover in absolute value is the difference between EIIs' demand in the ETS_R and the ETS_SAC case. The percentage is simply given by the ratio between the absolute recover and the absolute loss.

But not all EIIs benefit from the application of this new pricing scheme. In Germany, the Netherlands and the Belgian location Merchtem, industries face lower electricity prices than in the reference case. Relative price changes are between −19% (in Merchtem, Krimpen and Maastricht) and −17% (in Germany). Instead, in France and in the Belgian zone Gramme, the regional average cost prices are respectively 69 and 6% higher than the yearly marginal cost prices of the ETS_R scenario. This entails decreases of EIIs' electricity consumption of 22 and 1%, respectively in France and in Gramme. These cuts are globally compensated by the increases of EIIs' power demand in the other zones and the final result is the aforementioned 5% increase of industrial consumption. But the geopraphic outcome is quite differentiated.

6.2.2 EIIs' demand in the zonal average cost scenario

Zonal average cost based prices also have a global positive effect on EIIs: electricity consumption increases with respect to both the ETS_R (+6%) and the ETS_RAC (+2%) cases. It recovers 49% of the demand lost by the introduction of the EU-ETS. However, looking at the EIIs' hourly demand in Table 6, one can easily notice that industry behaviors differ depending on their location. Zonal average cost prices offer the best remedy to the EU-ETS in France and the Belgian zone Gramme. This mainly results from the technological generation structure in these locations. Zonal average cost pricing contracts perfectly suit industrial needs in a nuclear country like France, where EIIs have wide access to this cheap and clean technology without sharing it with foreign consumers.[18] Conversely, the situation of EIIs is more critical in zones where electricity is mostly produced by CCGT or coal technologies. This is the case in the Netherlands and in the Belgian zone Merchtem, where zonal prices really hurt industry.[19] In Germany, instead, the EIIs' electricity consumption decreases by 13% with respect to the ETS_RAC case, but it is higher than in the ETS_R scenario (+7%).

6.3 N-EIIs' electricity consumption and prices

Compared to the ETS_R case, the ETS_RAC model increases N-EIIs' power prices both in summer and winter. This is partially due to the endogenous split of capacity that reserves cheap and base-load technologies to EIIs and hence leaves the more expensive capacities to N-EIIs. This especially holds in France and in Gramme where N-EIIs have limited access to nuclear capacity, mainly devoted to EIIs. Consequently, CCGT plants set N-EIIs' electricity prices in summer after accounting for the corresponding carbon cost. In winter, natural gas and oil based installations become again active in Merchtem and in Krimpen. The EIIs' overall demand increase (+5%) dominates N-EII's global consumption reduction (−2%), as indicated in Table 7. The overall effect is a growth of the global amount of electricity produced which also raises the

[18] It is exactly the opposite of what happens in the ETS_RAC scenario.

[19] Their electricity cuts are as follows: 39% (ETS_R) and 52% (ETS_RAC) in Merchtem, 19% (ETS_R) and 36% (ETS_RAC) in Krimpen, 30% (ETS_R) and 45% in Maastricht and, finally, 31% (ETS_R) and −45% (ETS_RAC) in Zwolle.

Table 7 Annual electricity demand under different pricing scenarios (EIIs' elasticity −1)

TWh	N-EIIs			EIIs	Total
	Summer	Winter	Total		
NETS_R	250	399	649	598	1,248
ETS_R	244	402	646	531	1,177
ETS_RAC	243	391	634	555	1,189
ETS_ZAC	231	392	623	565	1,188

allowance price. Allowances now cost 28.48 €/ton, that is, +17% more than in the ETS_R scenario (24.44 €/ton).

The ETS_ZAC model induces N-EIIs to globally reduce their electricity consumption by 4% with regard to the ETS_R case (compare Table 7). We recall that, in a transmission constraint free system, N-EIIs' prices are determined by the most expensive power station (fuel and carbon costs) used to produce electricity. Coal and CCGT are at the margin, respectively in summer and in winter in both the ETS_R and the ETS_ZAC models; differences of electricity prices therefore only reflect carbon cost. In fact, allowances are cheaper in the ETS_R case than in the ETS_ZAC case (24.44 vs. 28.21 €/ton).

The comparison of the ETS_RAC and the ETS_ZAC cases also highlights that N-EIIs' consumption evolves differently depending on the zone and the period considered. The ETS_ZAC reduces the N-EIIs' summer consumption by 4.76% with respect to the ETS_RAC case in all zones but Merchtem. In contrast, only French N-EIIs lessen their electricity consumption (by 3.3%) in winter. Globally, the annual reduction amounts to 2% (see Table 7). These results are influenced both by the allowance price (that in this case is 28.21 €/ton) and the fuel mix.

7 Welfare analysis

Table 8 shows the welfare changes induced by the combination of the EU-ETS and these different pricing schemes.

Consumers globally loose with the introduction of the EU-ETS. N-EIIs recover best under a perfectly competitive market, while EIIs benefit most from buying electricity in the zonal average cost price. Their surplus respectively increases by 12 and 16%, compared to the ETS_R and the ETS_RAC cases.

Generators also generally loose with the introduction of the EU-ETS, at least if they have to pay for allowances. We report profits in Table 8, assuming free allowances and also indicate the value of the allowances (see "Allowances" row in Table 8). Generators' benefits increase when allowances are free but decrease otherwise. These results are in line with the theory of the so–called windfall profits (see Sijm et al. 2006). Subtracting the value of allowances from the profits one observes that full auctioning, apart from the ETS_ZAC case, decreases generators' profits with respect to the NETS_R model.

Table 8 Welfare under different pricing scenarios (EIIs' elasticity −1)

Billion €	NETS_R	ETS_R	ETS_RAC	ETS_ZAC
EIIs	15.53	12.08	11.64	13.49
N-EIIs	130.87	129.35	124.65	120.20
Consumers	**146.40**	**141.43**	**136.29**	**133.69**
Generators	**25.22**	**29.25**	**32.94**	**36.78**
Allowances		*9.70*	*11.32*	*11.21*
TSO	**0.65**	**0.90**	**1.26**	**0.10**
Welfare	**172.27**	**171.58**	**170.49**	**170.58**

The sum of the values in bold gives the final welfare

Finally, the TSO's merchandising surplus depends on network utilization, which itself depends on the price policy. The introduction of the EU-ETS makes CO_2 free resources more valuable and hence induces a tendency to resort to nuclear energy. Because these plants are not uniformly located in CWE, transmission activity increases. The regional average cost pricing system exacerbates this trend therefore dramatically increasing merchandising surplus. In contrast, the zonal average cost system drastically decreases the need for transmission as the TSO only deals with N-EIIs' transactions. One can note in passing that the figures of the total welfare are compatible with the standard result of economic theory that perfect competition maximizes global welfare.

8 Sensitivity and robustness analysis

We here conduct both a sensitivity and a robustness analyses in order to check the variation of EIIs' demand and emissions with assumptions on the allowance market and EIIs' price elasticity.

8.1 Sensitivity analysis

The preceding discussion concentrated on the case of an endogenously determined carbon price. We here simplify the models by directly introducing an exogenous allowance price and test two cases where:

1. the allowance price is set at 20 €/ton ("AP20" case);
2. the allowance price is set at 70 €/ton ("AP70" case)

to which we apply the pricing scheme policies described before. A price of 20 €/ton is commonly used as a reference for allowances (McKinsey and Ecofys 2006; Reinaud 2005); we believe that an allowance price 70 €/ton is in line with the target of the European Commission for the period 2013–2020 when a new emission and renewable commitments will be introduced (see Argus 2008).

We then compare the results of these scenarios with the values obtained in the corresponding models with endogenous carbon price (AP-endo). These tests require a small modification of our models. An exogenous allowance price dispenses with the need to explicitly model the carbon market as generators buy and sell allowances at

Table 9 Emission level under different pricing scenarios

Mio ton		AP-endo	AP20	AP70
NETS_R	464			
ETS_R		397	407	104
ETS_RAC		397	441	256
ETS_ZAC		397	423	256

exogenously given prices. In contrast with the previous analysis, we thus first define an allowance price and then compute the amount of emissions. Note that the endogenous allowance prices found in the previous sections are higher than the 20 €/ton tested here. A lower allowance price induces a higher emission level, while the reverse happens when we experiment an allowance price of 70 €/ton.

8.1.1 AP20 case

The contribution of CO_2 to the electricity price is relatively low when the allowance price is 20 €/ton. This encourages EIIs to increase their power consumption with a consequent augment of the emission level compared to the results presented so far. This happens in all scenarios studied with emissions raising respectively by 3% (ETS_R), 11% (ETS_SAC) and 7% (ETS_NAC) with respect to our cap of 397 Mio ton p.a. (see Table 9). Note that, after adopting this allowance price, the zonal average cost model still guarantees the highest consumption level for industries. This confirms the advantage of the zonal average cost price.

8.1.2 AP70 case

The demand pattern changes with an emission price of 70 €/ton. Industries drastically reduce their electricity consumption in the ETS_R case. From 68,294 MWh in NETS_R, it falls to 25,439 MWh (−58%). Reductions are comparatively lower in the regional and in the zonal average cost cases [respectively 50,886 (−20%) and 56,379 MWh (−13%)], suggesting that average cost based contracts again play their role of protecting the competitiveness of the EIIs.

Generators pass the high carbon cost in the electricity price in the reference ETS_R scenario. The summer prices are between 52.85 €/ton and 66.59 €/MWh.[20] The winter price is 82.76 €/MWh in all zones, since the network is not congested. The high fall of industrial electricity consumption is obviously due to the −1 elasticity assumption used in the industrial sector, but N-EIIs also reduce their power demand, even though cuts are much lower (−2% in summer and −9% in winter). The imposition of such a high allowance price allows European Member States to easily exceed their emission reduction targets. Table 9, reports emissions reductions by 78% with respect to the annual 397 Mio ton target of the AP-endo version of ETS_R model. This results from both the drop in electricity consumption and the increased exploitation of clean tech-

[20] This holds in all zones, except in France and in Gramme where power prices are respectively 4.50 and 26.33 €/MWh.

Table 10 Annual electricity demand under different pricing scenarios (EIIs' elasticity −0.8)

TWh	N-EIIs			EIIs	Total
	Summer	Winter	Total		
NETS_R	250	399	650	586	1,236
ETS_R	243	402	645	524	1,169
ETS_RAC	243	391	634	554	1,188
ETS_ZAC	240	396	636	556	1,191

nologies. In summer, a great part of the electricity required by consumers is covered by hydro, renewable and nuclear. Few CCGT plants are run in the Netherlands. Network congestion contributes to making electricity prices high. In winter, clean technologies and CCGT are fully run and a small proportion of lignite plants are exploited in Germany.

Here again, the average cost based contracts help industries healing this negative impact of the environmental policy. In particular, the AP70 ETS_SAC model allows EIIs to recover 59% of their lost consumption with respect of their NETS_R level, while in the AP70 ETS_NAC case the gain is +72%. The advantage of the zonal average cost price is again confirmed. As already observed in the preceding sections, N-EIIs pay for this recovery.

8.2 Further robustness analysis

We further check the robustness of our results by analyzing the case when EIIs' demand is less elastic. Starting from the same reference demand point (see Sect. 2), we assume an industrial demand elasticity of −0.8. This assumption obviously leads to different results, but preserves consumption and price trends. Table 10 reports annual consumers' demand.

As in Table 7, EIIs increase their electricity consumption in the average cost pricing systems. The increment is again higher in the ETS_ZAC model. As before, N-EIIs suffer from the application of the price discrimination and reduce their power demand both in the ETS_RAC and in the ETS_ZAC scenarios.

Finally, Table 11 reports the results of the welfare analysis conducted with the -0.8 elasticity assumption.

9 Conclusion

The special average cost based contracts tested in this paper represent one response proposal of European industrial consumers to the new situation created by the EU-ETS. It implies a change of the electricity pricing system with the view of mitigating the increase of electricity prices caused by the EU-ETS. We test two different average cost pricing policies, regional and zonal, that have different effects on industries.

A common point, discussed in Sect. 6, is that average cost based pricing encourages EIIs to maintain their activities (here represented by consumption of electricity) with respect to the reference level at least under the condition retained in this model (exog-

Table 11 Welfare under different pricing scenarios (EIIs' elasticity −0.8)

Billion €	NETS_R	ETS_R	ETS_RAC	ETS_ZAC
EIIs	18.12	14.28	14.47	15.33
N-EIIs	131.01	129.05	124.65	125.29
Consumers	**149.13**	**143.33**	**139.12**	**140.62**
Generators	**25.00**	**29.79**	**32.77**	**32.46**
Allowances		*10.44*	*11.31*	*11.30*
TSO	**0.66**	**0.94**	**1.26**	**0.78**
Welfare	**174.79**	**174.06**	**173.15**	**173.86**

The sum of the values in bold gives the final welfare

enous capacities and efficient transmission market). However, neither the regional nor the zonal average cost pricing mechanisms completely mitigate the burdens imposed by the EU-ETS on the industrial sector. The first policy negatively affects French and part of the Belgian electricity intensive users, who, instead, profit in the second average cost pricing strategy. In Germany, in Merchtem and in all Dutch zones, industries face the opposite situation. The conclusion is that the impact of these special contracts on EIIs depends on the particular pricing scheme implemented (regional or zonal) and on the energy policy applied in the countries where these industries operate. Another, more far reaching, conclusion is that discrepancies of energy policies in the EU will probably seriously harm other policies, such as environmental protection and competition. This results from the fact that energy policies are significant determinants of energy costs and hence, in this analysis, of energy prices.

Finally, the high emission allowance price reveals the stress that the generation system is currently subject to. This suggests that investments are very needed to heal these tensions. Looking at this problem requires capacity expansion model; this is undertaken in Oggioni and Smeers (2008a,b).

Acknowledgments The authors gratefully acknowledge Thierry Bréchet, Andreas Ehrenmann and Chefi Triki for their advices. We also thank the anonymous referee for his/her comments.

Appendix A. Mixed complementarity problems (MCPs)

From a mathematical point of view, CPs are defined as follows:

Definition 1 Given a mapping $F : \mathbb{R}^n_+ \to \mathbb{R}^n$, the CP is to find a vector $x^* \in \mathbb{R}^n$ such that:

$$0 \leq x^* \perp F(x^*) \geq 0 \tag{1}$$

The term "complementarity" used to indicate this condition derives directly from the concept of orthogonality ($\perp$) stated by definition. In other words, solving a CP consists in finding $x^* \geq 0$ such that:

$$F(x^*) \geq 0 \quad \text{and} \quad F(x^*)x^* = 0 \tag{2}$$

Condition (1) is the compact form that we also adopt in our models. The *mixed complementarity problem* (MCP) extends this notion as follows. Let y be another vector of variables and $G(x, y)$ be a vector valued function with the same dimension as y. A MCP can be stated as finding x^*, y^* such that:

$$\begin{aligned} &0 \leq F(x^*, y^*) \perp x^* \geq 0 \\ &G(x^*, y^*) = 0 \end{aligned} \tag{3}$$

Complementarity-based models offer a natural approach to construct equilibrium model. A market comprises different agents that produce, trade and consume different commodities. Standard microeconomic theory suggests to represent each agent by an optimization problem (profit or surplus maximization). Complementarity models readily derive from this principle. Complementarity-based formulations are created by first writing the KKT conditions of the optimization problems of the agents included in the models studied[21] and, then, adding market clearing (or equilibrium conditions).[22] Note that our models are formulated as MCPs, since we add the equilibrium (market clearing) conditions of the electricity to the complementarity problems. These MCPs are implemented in the GAMS modelling environment, using PATH as solver (see Dirkse and Ferris 1995).

Appendix B. Reference case with emission and transmission constraints

This appendix presents the reference ETS model with both emission and transmission constraints. We first list the indices, parameters and variables and then present the model both in optimization and complementarity forms. Recall that we follow Stoft's approach (see Stoft 2002) that allows us to conduct the whole discussion on an hourly basis and thus to express capacities in MWh (instead of MW). Note the outset that we write the inverted demand functions (price as function of quantities) in the form $P_i^{t,c}(d_i^{t,c}) = a_i^{t,c} - b_i^{t,c} d_i^{t,c}$.

Appendix B.1. Notation of the reference case

The sets, parameters and variables are as follows:

A. **Indexes and sets**

$i \in I$ Set of active zones in the transmission network;
$f \in F$ Set of generators;

[21] In our case, generators and consumers.

[22] Emission and transmission constraints and equilibrium on energy, emission and transmission markets.

$m \in M$	Set of generation technologies;
$l \in L$	Set of flowgates (or lines) of the transmission grid;
$c \in \{1, 2\}$	Set of consumer group (EIIs "*1*" and N-EIIs "2");
$t \in \{s, w\}$	Set of time segments/seasons (summer '*s*" and winter "*w*").

B. **Parameters**

Generators

$\mathrm{G}_{f,i,m}$	Hourly capacity of plant type m owned by generator f at zone i (in MWh);
$\mathrm{cost}_{f,i,m}$	Variable costs of unit m owned by generator f at zone i (in €/MWh).

Consumers (EIIs and N-EIIs)

$\mathrm{a}_i^{t,c}$	Intercept of consumers' affine demand function at zone i and season t (in €/MWh);
$\mathrm{b}_i^{t,c}$	Slope of consumers' affine demand function at zone i and season t (in €/MWh^2)

EU-ETS

CAP	Total annual emission cap of the power market analyzed (in ton);
em_m	Emission factor of technology m used (in ton/MWh).

Network

$\mathrm{PTDF}_{l,i}$	PTDF matrix of zone i on line l;
$\mathrm{Linecap}_l$	Hourly limit of flow through line l (in MWh).

Period durations

hour^t	Duration in hours of each season t;
$\mathrm{proportion}^t$	Proportion of duration of each season t in the year (%).

C. **Variables**

Generators

$g_{f,i}^t$	Hourly power sold at zone i by generator f in season t (in MWh);
$gp_{f,i,m}^t$	Hourly power generated by unit m owned by generator f at zone i in season t (in MWh);
$\nu_{f,i,m}^t$	Marginal hourly value of capacity (scarcity rent) of technology m of generator f at zone i and in season t (in €/MWh);
$\eta_{f,i}^t$	Marginal production cost of generator f at zone i and in season t (in €/MWh).

Consumers (EIIs and N-EIIs)

$d_i^{t,c}$	Hourly power consumption of consumers c located at zone i in season t (in MWh);
$P_i^{t,c}(d_i^{t,c})$	Inverse demand function (price or a function of quantity) of consumers c located at zone i in season t.

Electricity prices

p_i^t Electricity price at zone i in season t (in €/MWh);
$phub^t$ Electricity price at the hub in season t (in €/MWh);
α_i Technical auxiliary variable related to the constraint imposing the constant hourly consumption of EIIs in the two seasons (in €/MWh) (see later).

EU-ETS

λ Allowance price (in €/ton).

Network

$\mu_l^{t,+,-}$ Congestion rent of line l; depending on flow direction (+, −) in season i (in €/MWh).

Appendix B.2. Modelling the reference case

The reference model describes a perfectly competitive energy market operating together with perfectly competitive zonal transmission and allowance markets. Agents are price takers in perfect competition and all prices are set at marginal (opportunity) cost. This applies to the energy as well as to the transmission and emission markets. The model consists of two seasonal sub-models (summer and winter) coupled by two inter-seasonal links: (1) EIIs' consumption is identical in the two seasons and the dual variable α_i of condition (17) defines the link between the summer and the winter industrial consumptions; (2) the total emission constraint is defined on a yearly basis [as stated in condition (26)]. Recall that λ is the allowance price (determined by the emission allowances clearing (26) to which we shall return later) and p_i^t is the electricity price in zone i and season t.

The construction of the model expresses the following phenomena. Generators maximize their profits; consumers maximize their surplus; the TSOs globally maximize their merchandising surplus; the energy, transmission and emission markets clear. We successively model these problems.

(i) Generators maximize their profits

Using the notation listed before, generator f's hourly profit maximization in season t is stated as follows:

$$\mathbf{Max} \quad \sum_i p_i^t \cdot g_{f,i}^t - \sum_{i,m} (\text{cost}_{f,i,m} + \text{em}_m \cdot \lambda) \cdot gp_{f,i,m}^t \tag{4}$$

s.t.

$$0 \leq \sum_m gp_{f,i,m}^t - g_{f,i}^t \qquad (\eta_{f,i}^t) \quad \forall\, t, f, i \tag{5}$$

$$0 \leq \mathrm{G}_{f,i,m} - gp_{f,i,m}^t \qquad (\nu_{f,i,m}^t) \quad \forall\, t, f, i, m \tag{6}$$

$$0 \leq g_{f,i}^t \quad \forall\, t, f, i \tag{7}$$

$$0 \leq gp_{f,i,m}^t \quad \forall\, t, f, i, m \tag{8}$$

where the dual variable $\eta^t_{f,i}$ is the short-run marginal production costs faced by generator f in zone i and season t; while $\nu^t_{f,i,m}$ denotes the scarcity rent, which corresponds to the marginal value of capacity m. Note that this is positive only when capacity is fully used.

The corresponding KKT conditions are stated as:

$$0 \leq -p^t_i + \eta^t_{f,i} \perp g^t_{f,i} \geq 0 \quad \forall\, t,\, f,\, i \tag{9}$$

$$0 \leq \text{cost}_{f,i,m} + \text{em}_m \cdot \lambda + \nu^t_{f,i,m} - \eta^t_{f,i} \perp gp^t_{f,i,m} \geq 0 \quad \forall\, t,\, f,\, i,\, m \tag{10}$$

$$0 \leq \mathrm{G}_{f,i,m} - gp^t_{f,i,m} \perp \nu^t_{f,i,m} \geq 0 \quad \forall\, t,\, f,\, i,\, m \tag{11}$$

$$0 \leq \sum_m gp^t_{f,i,m} - g^t_{f,i} \perp \eta^t_{f,i} \geq 0 \quad \forall\, t,\, f,\, i \tag{12}$$

Condition (10) states that the generators' marginal costs $\eta^t_{f,i}$ equal fuel ($\text{cost}_{f,i,m}$), emission opportunity ($\text{em}_m \cdot \lambda$) and marginal capacity ($\nu^t_{f,i,m}$) costs. These costs are all remunerated by the marginal electricity price p^t_i as stated in condition (9).

(ii) N-EIIs and EIIs maximize their surplus

N-EIIs' hourly surplus maximization in season t at zone i is expressed as:

$$\textbf{Max} \quad \int_0^{d^{t,2}_i} P^{t,2}_i(\xi)d\xi - p^t_i \cdot d^{t,2}_i \tag{13}$$

leading to the optimality condition:

$$P^{t,2}_i(d^{t,2}_i) = p^t_i \tag{14}$$

or after replacing $P^{t,2}_i(d^{t,2}_i)$ by its affine expression:

$$p^t_i = \mathrm{a}^{t,2}_i - \mathrm{b}^{t,2}_i \cdot d^{t,2}_i \qquad \forall\, t,\, i \tag{15}$$

We assume that the quantity of electricity needed for EIIs' production activities is constant over time. In order to model this assumption, we first split EIIs' electricity demand $d^{t,1}_i$ and the electricity prices p^t_i in sub-variables (respectively $d^{s,1}_i$, $d^{w,1}_i$ and p^s_i, p^w_i) accounting explicitly for the two periods, summer and winter, presented in the model. We then add condition (17) to impose the equality between hourly industrial summer (s) and winter (w) consumption. This condition is matched with the dual variable α_i, which represents the link between the summer and the winter EIIs' price and demand. EIIs' hourly surplus maximization in zone i is thus expressed as:

$$\textbf{Max} \quad \text{proportion}^s \cdot \left(\int_0^{d_i^{s,1}} P_i^{s,1}(\xi)d\xi - p_i^s \cdot d_i^{s,1} \right) \tag{16}$$

$$+\text{proportion}^w \cdot \left(\int_0^{d_i^{w,1}} P_i^{w,1}(\xi)d\xi - p_i^w \cdot d_i^{w,1} \right)$$

s.t.

$$d_i^{s,1} = d_i^{w,1} \quad (\alpha_i) \quad \forall\, i \tag{17}$$

or after expressing the optimality condition and replacing the functions $P_i^{t,1}(d_i^{t,1})$ by their expressions for $t = s, w$:

$$\text{proportion}^s \cdot p_i^s - \alpha_i = (\mathrm{a}_i^{s,1} - \mathrm{b}_i^{s,1} \cdot d_i^{s,1}) \cdot \text{proportion}^s \quad (d_i^{s,1}) \quad \forall\, i \tag{18}$$

$$\text{proportion}^w \cdot p_i^w + \alpha_i = (\mathrm{a}_i^{w,1} - \mathrm{b}_i^{w,1} \cdot d_i^{w,1}) \cdot \text{proportion}^w \quad (d_i^{w,1}) \quad \forall\, i \tag{19}$$

$$d_i^{s,1} = d_i^{w,1} \quad (\alpha_i) \quad \forall\, i$$

Recall that p_i^t in the N-EIIs' model replaces p_t^s and p_i^w in the EIIs' maximization problem. Moreover, $d_i^{t,2}$, $d_i^{s,1}$ and $d_i^{w,1}$ are positive quantities.

(iii) Clearing of the energy market

Electricity is not storable. Equality of electricity production and consumption is necessary at all moments of time. Neglecting losses, we express this balance at the so-called hub in equality (20).

$$\sum_{f,i} g_{f,i}^t - \sum_i d_i^{t,1} - \sum_i d_i^{t,2} = 0 \ \ (phub^t) \quad \forall\, t \tag{20}$$

The dual variable $phub^t$ represents the market clearing price at the hub, a virtual market where all electricity asks and bids clear. It is positive when the condition holds.

(iv) The TSOs' problem: clearing of the transmission market

We model the transmission system according to a flowgate representation. This model is extensively discussed in the literature and it is intended to be implemented in the CWE region. It is easily described by assuming that the TSOs collectively maximize the value that they get from selling transmission services according to the possibilities of the network. Abusing notation and using $g_{f,i}^t$ and $d_i^{t,1} + d_i^{t,2}$, respectively for injection and withdrawal services sold by TSOs, their maximization problem is stated for each t as:

$$\mathbf{Max} \quad \sum_i p_i^t \cdot \left(d_i^{t,1} + d_i^{t,2} - \sum_f g_{f,i}^t \right) \tag{21}$$

s.t.

$$-\,\text{Linecap}_l \leq \sum_i \text{PTDF}_{l,i} \left(\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2} \right) \leq \text{Linecap}_l \qquad (\mu_l^{t,\pm}) \quad \forall\, t, l \tag{22}$$

Condition (22) describes the transmission constraints in the flowgate representation. The PTDF matrix determines both the patterns and the proportions of power flowing through network lines. Specifically, it defines the flow through line l resulting from a unit injection in zone i and withdrawal at the hub (assuming no losses). A basic security constraint is that the sum of the flows in lines does not exceed their respective capacities (Linecap_l). This limits the set of possible injections and withdrawals. Congestion arises when at least one of the grid lines is overloaded. This must hold for any load pattern. We must therefore introduce two transmission constraints as well as dual variables ($\mu_l^{t,+}$; $\mu_l^{t,-}$) to account for the two possible directions of power flows. The corresponding KKT conditions are stated as:

$$p_i^t = phub^t + \sum_l (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot \text{PTDF}_{l,i} \quad \forall\, t, i \tag{23}$$

$$0 \leq \text{Linecap}_l - \left(\sum_i \text{PTDF}_{l,i} \cdot \left(\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2} \right) \right) \perp \mu_l^{t,+} \geq 0 \quad \forall\, t, l \tag{24}$$

$$0 \leq \text{Linecap}_l + \left(\sum_i \text{PTDF}_{l,i} \cdot \left(\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2} \right) \right) \perp \mu_l^{t,-} \geq 0 \quad \forall\, t, l \tag{25}$$

Condition (23) illustrates how the marginal electricity prices paid by both consumer segments are formed. Following the zonal pricing theory, zonal marginal electricity prices p_i^t are given by the price at the $phub^t$ [as from condition (20)] plus the congestion charges ($\sum_l (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot \text{PTDF}_{l,i}$) that the TSOs receive from transporting energy. Transmission costs affect electricity price making them different over zones as soon as one line is congested in the system. The regulation of the system implies that the generator receives and the consumer pays zonal prices (the balance is the merchandising surplus collected by the TSOs). The result is that consumers situated in the hub only pay the hub price and do not face the network costs. Last but not the least, the algebraic sum $-\mu_l^{t,+} + \mu_l^{t,-}$ can assume a positive or a negative sign, depending on the direction of the flow that congests the line.

(v) Clearing of the emission market

Since the emission NAPs are set by year in the model, the allowance market clears on an annual basis giving a unique allowance price. The emission complementarity constraint (26) expresses that the total amount of emission produced over the year can not exceed the annual emission CAP. As indicated in (26), total emissions are given by hourly generation $g^t_{f,i,m}$ time the number of hours in each period $hour^t_i$ and the emission factor em_m. The value of the allowance price λ is positive when total emissions equal the CAP. This means that the emission cap is binding. This opportunity cost influences electricity prices and firms' market optimality conditions [see condition (10)]. We recall that, in order to simplify the presentation, we model a closed allowance market restricted to the power sector. This implies that the emission cap CAP is exactly equal to the sum of generators' NAPs.[23]

$$0 \leq \mathrm{CAP} - \sum_{t,f,i,m} g^t_{f,i,m} \cdot \mathrm{em}_m \cdot \mathrm{hour}^t_i \perp \lambda \geq 0 \tag{26}$$

Appendix C. Average cost pricing models

In this appendix, we present the regional and the zonal average cost pricing models formulated as mixed complementarity problems. We list the variables; the parameters are the same as those of Appendix B.1.

- **Variables**

Generators

$g^1_{f,i}$; $g^{t,2}_{f,i}$ Hourly power sold at zone i by generator f, respectively to EIIs (noted "1") and N-EIIs (noted "2") (in MWh). N-EIIs' variable differs by season t;

$gp^1_{f,i,m}$; $gp^{t,2}_{f,i,m}$ Hourly generation by unit m owned by generator f at zone i to supply, respectively EIIs (noted "1") and N-EIIs (noted "2") (in MWh). N-EIIs' variable differs by season t;

$G^1_{f,i,m}$; $G^2_{f,i,m}$ Hourly capacity of type m that generator f located in i dedicates, respectively to EIIs (noted "1") and N-EIIs (noted "2") (in MWh);

$\nu^1_{f,i,m}$; $\nu^{t,2}_{f,i,m}$ Marginal hourly value of capacity (scarcity rent) of technology m of generator f at zone i allocated to EIIs (noted "1") and N-EIIs (noted "2") (in €/MWh). N-EIIs' variable differs by season t;

$\eta^1_{f,i}$; $\eta^{t,2}_{f,i}$ Marginal production cost of generator f at zone i concerning, respectively EIIs (noted "1") and N-EIIs (noted "2") (in €/MWh). N-EIIs' variable differs by season t;

$\nu_{f,i,m}$ Marginal hourly value of capacity of technology m of generator f at zone i (in €/MWh) (see below for the relation with $\nu^1_{f,i,m}$ and $\nu^{t,2}_{f,i,m}$).

[23] We recall that during the pilot ETS phase (2005–2007) we are modelling, allowances were totally distributed for free at least in the countries included in our model.

Consumers (EIIs and N-EIIs)

$d_i^1; d_i^{t,2}$ Hourly power consumption, respectively by EIIs (noted "1") and N-EIIs (noted "2") located at zone i (in MWh). N-EIIs' variable differs by season t (in MWh);

$P_i^1(d_i^1); P_i^{t,2}(d_i^{t,2})$ Inverse demand function, respectively of the EIIs (noted "1") and N-EIIs (noted "2"). N-EIIs' function differs by season t.

Electricity prices

p^1 Regional average cost price of electricity paid by industries (noted "1"). It is composed of two terms: the regional production ($pprod^1$, including the allowance cost) and the regional transmission ($ptrans^1$) average costs (in €/MWh);

p_i^1 Zonal average cost price of electricity paid by industries (noted "1") (in €/MWh);

$p_i^{t,2}$ Zonal price paid by N-EIIs (noted "2") in each season t (in €/MWh);

$phub^{t,2}$ Electricity price at the hub in each season t for N-EIIs (noted "2") (in €/MWh);

β^1 Marginal cost at the hub of the electricity generated by the capacities dedicated to industries (in €/MWh); this variable intervenes in the regional average cost price model;

β_i^1 Marginal cost at the zone i of the electricity generated by the capacities dedicated to industries (in €/MWh); these variables intervene in the zonal average cost price model.

Appendix C.1. Regional average cost pricing model

The regional average cost pricing model assumes that EIIs constitute a power purchase consortium that buys electricity from plants located in different zones of the network through long-term contracts. Their electricity price is thus regional. The model implies both a market segmentation and a price discrimination: a marginal cost pricing system applies to N-EIIs and an average cost pricing mechanism is in force for EIIs. The apexes "*1*" and "*2*" are adopted to indicate respectively EIIs and N-EIIs' variables. Moreover, since EIIs' electricity consumption is constant, we now assume that their variables do not depend on time t; while we still maintain the time dependence in N-EIIs' variables. Their model structure is similar to that of the reference model. Note that we can make these assumptions thanks to the hypotheses of market segmentation and price discrimination characterizing these models.

The driving principle of this arrangement is that generators allocate their capacity to these two market segments that are themselves subject to different pricing arrangements. Generators maximize the profit accruing from sales to N-EIIs (without exercising market power) implying that N-EIIs remain subject to marginal cost pricing. Generators also minimize the cost of supplying EIIs and charge the average cost of this supply. The main structure of the transmission and allowance market clearing remains unchanged. We now describe the different aspects of the model, starting with the TSOs' problem. Again, we present both the optimization and the complementarity versions of these agents' problems.

(i) The TSOs' model: clearing of the transmission market.

The TSOs' model minimally differs from the one presented in Appendix B.2. Replacing $d_i^{t,1}$ by d_i^1 and $g_{f,i}^t$ by $g_{f,i}^1$ and $g_{f,i}^{t,2}$ to respectively refer to EIIs and N-EIIs variables, we restate the complementarity conditions of the TSOs' problem as follows:

$$p_i^{t,2} = phub^t + \sum_l \left(-\mu_l^{t,+} + \mu_l^{t,-}\right) \cdot \mathrm{PTDF}_{l,i} \quad \forall\, t, i \tag{27}$$

$$0 \le \mathrm{Linecap}_l - \left(\sum_i \mathrm{PTDF}_{l,i} \cdot \left(\sum_f g_{f,i}^1 + \sum_f g_{f,i}^{t,2} - d_i^1 - d_i^{t,2}\right)\right) \perp \mu_l^{t,+} \ge 0 \quad \forall\, t, l \tag{28}$$

$$0 \le \mathrm{Linecap}_l + \left(\sum_i \mathrm{PTDF}_{l,i} \cdot \left(\sum_f g_{f,i}^1 + \sum_f g_{f,i}^{t,2} - d_i^1 - d_i^{t,2}\right)\right) \perp \mu_l^{t,-} \ge 0 \quad \forall\, t, l \tag{29}$$

where $p_i^{t,2}$ are the marginal cost based prices paid by N-EIIs.

(ii) Generators maximize profits on the N-EII market segment.

The formulation is identical to the one of the reference model in Appendix B.2, but is here restricted to the N-EII market. We thus have for each t:

$$\textbf{Max} \quad \sum_i p_i^{t,2} \cdot g_{f,i}^{t,2} - \sum_{i,m} \left(\mathrm{cost}_{f,i,m} + \mathrm{em}_m \cdot \lambda\right) \cdot gp_{f,i,m}^{t,2} \tag{30}$$

s.t.

$$0 \le \sum_m gp_{f,i,m}^{t,2} - g_{f,i}^{t,2} \qquad (\eta_{f,i}^{t,2}) \quad \forall\, t, f, i \tag{31}$$

$$0 \le G_{f,i,m}^2 - gp_{f,i,m}^{t,2} \qquad (\nu_{f,i,m}^{t,2}) \quad \forall\, t, f, i, m \tag{32}$$

$$0 \le gp_{f,i,m}^{t,2} \quad \forall\, t, f, i, m \tag{33}$$

$$0 \le g_{f,i}^{t,2} \quad \forall\, t, f, i \tag{34}$$

The corresponding KKT conditions are stated as:

$$0 \le \eta_{f,i}^{t,2} - p_i^{t,2} \perp g_{f,i}^{t,2} \ge 0 \quad \forall\, t, f, i \tag{35}$$

$$0 \le \mathrm{cost}_{f,i,m} + \mathrm{em}_m \cdot \lambda + \nu_{f,i,m}^{t,2} - \eta_{f,i}^{t,2} \perp gp_{f,i,m}^{t,2} \ge 0 \quad \forall\, t, f, i, m \tag{36}$$

$$0 \le \sum_m gp_{f,i,m}^{t,2} - g_{f,i}^{t,2} \perp \eta_{f,i}^{t,2} \ge 0 \quad \forall\, t, f, i \tag{37}$$

$$0 \le G_{f,i,m}^2 - gp_{f,i,m}^{t,2} \perp \nu_{f,i,m}^{t,2} \ge 0 \quad \forall\, t, f, i, m \tag{38}$$

(iii) Generators minimize their generation, emission and transmission costs of supplying the EII segment

Since we assume that EIIs' demand is constant over time, we impose that the variables describing the industrial segment' problem do not depend on time t. Let d_i^1 be the demand level of EIIs in market 1. Generators globally solve the problem:

$$\begin{aligned}\textbf{Min} \quad & \sum_{f,i,m} \left(\mathrm{cost}_{f,i,m} + \mathrm{em}_m \cdot \lambda\right) \cdot gp^1_{f,i,m} \\ & - \sum_{f,t,i,l} \left[(-\mu_l^{t,+} + \mu_l^{t,-}) \cdot \mathrm{proportion}^t \cdot \mathrm{PTDF}_{l,i}\right] \cdot (g^1_{f,i} - d_i^1)\end{aligned} \tag{39}$$

s.t.

$$0 \leq \sum_m gp^1_{f,i,m} - g^1_{f,i} \qquad (\eta^1_{f,i}) \quad \forall\, f, i \tag{40}$$

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \qquad (\nu^1_{f,i,m}) \quad \forall\, f, i, m \tag{41}$$

$$\sum_{f,i} g^1_{f,i} - \sum_i d_i^1 = 0 \ \ (\beta^1) \tag{42}$$

$$0 \leq g^1_{f,i} \quad \forall\, f, i \tag{43}$$

$$0 \leq gp^1_{f,i,m} \quad \forall\, f, i, m \tag{44}$$

The term $(\mathrm{cost}_{f,i,m} + em_m \cdot \lambda)$ appearing in this objective function corresponds to the fuel and emission costs; it has been encountered in the reference model and needs no further explanation. The second term:

$$\left[(-\mu_l^{t,+} + \mu_l^{t,-}) \cdot \mathrm{proportion}^t \cdot \mathrm{PTDF}_{l,i}\right]$$

is the congestion cost incurred because of the supply to the industry.

The KKT conditions of this optimization problem can be stated as follows:

$$0 \leq \eta^1_{f,i} - \beta^1 - \left(\sum_{t,l} \left(-\mu_l^{t,+} + \mu_l^{t,-}\right) \cdot \mathrm{proportion}^t \cdot \mathrm{PTDF}_{l,i}\right) \perp g^1_{f,i} \geq 0 \quad \forall\, f, i \tag{45}$$

$$0 \leq \mathrm{cost}_{f,i,m} + \mathrm{em}_m \cdot \lambda + \nu^1_{f,i,m} - \eta^1_{f,i} \perp gp^1_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{46}$$

$$0 \leq \sum_m gp^1_{f,i,m} - g^1_{f,i} \perp \eta^1_{f,i} \geq 0 \quad \forall\, f, i \tag{47}$$

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \perp \nu^1_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{48}$$

The meaning of these complementarity conditions is similar to those of the reference model in Appendix B.2. The dual variable β^1 is meant to represent the hypothetical marginal cost price that industries should pay, at the hub, under a perfectly competitive regime. Our empirical results show that its value (54.10 €/MWh) corresponds exactly to the average of the $phub^{t,2}$ on the N-EIIs' market weighted by season duration. It is worthwhile explaining that the EIIs' problem effectively embeds two different pricing structures. One is real in the sense that it corresponds to the commercial transactions, e.g., what EIIs pay to the generators and the TSO. The other is virtual in the sense that it consists in transfer prices that ensure efficient internal operations of the capacities dedicated to industries. The average cost price p^1 [see (59)], including the average production and transmission costs is what is effectively paid for electricity trading. In contrast, the marginal cost price β^1 that pairs with the electricity balance of the industrial sector plays the role of an internal transfer price. The similarity of β^1 with $phub^{t,2}$ can be seen by first observing the relation (45) where in addition to the transmission charges β^1 assumes the role of $p_i^{t,2}$ for N-EIIs in condition (35).

(iv) Generators allocate their capacity efficiently between the N-EII and EII market segments

Adopting a standard efficiency criterion, we assume that the allocation of the generation capacity between the two market segments is conducted so as to equalize the marginal value of the capacities. This can be expressed as follows:

$$0 \leq \mathrm{G}_{f,i,m} - G^1_{f,i,m} - G^2_{f,i,m} \perp \nu_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{49}$$

$$0 \leq G^2_{f,i,m} - gp^{t,2}_{f,i,m} \perp \nu^{t,2}_{f,i,m} \geq 0 \quad \forall\, t, f, i, m$$

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \perp \nu^1_{f,i,m} \geq 0 \quad \forall\, f, i, m$$

$$0 \leq \nu_{f,i,m} - \sum_t \nu^{t,2}_{f,i,m} \cdot \mathrm{proportion}^t \perp G^2_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{50}$$

$$0 \leq \nu_{f,i,m} - \nu^1_{f,i,m} \perp G^1_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{51}$$

These conditions can be interpreted as follows. The split of capacity is endogenously determined as shown by constraints (38) and (48). Variables $G^2_{f,i,m}$ and $G^1_{f,i,m}$ define the plant capacities respectively dedicated to N-EIIs and EIIs. Condition (49) states that the sum of the MWh capacities reserved for N-EIIs ($G^2_{f,i,m}$) and EIIs ($G^1_{f,i,m}$) should not exceed the total power capacity ($\mathrm{G}_{f,i,m}$) installed in the market. Recall that $\mathrm{G}_{f,i,m}$ is a parameter.

Condition (49) is then matched with the variable $\nu_{f,i,m}$ representing the global scarcity rent. The variable $\nu_{f,i,m}$ together with the variables $\nu^{t,2}_{f,i,m}$ and $\nu^1_{f,i,m}$ appearing in (50) and (51) ensures the effectiveness of the split in capacity between the two consumer sectors. Recall that the parameter $\mathrm{proportion}^t$ in (50) determines the proportions of the duration of each period t. Looking at conditions (50) and (51), one then notices that $\nu_{f,i,m}$ implicitly defines an equality between $\nu^{t,2}_{f,i,m}$ and $\nu^1_{f,i,m}$. This equality therefore implies that the marginal values of capacity are identical for N-EIIs and EIIs, even if their electricity prices are determined by using two different approaches. This implies that the allocation of the capacity maximizes its total value.

(v) N-EIIs and EIIs maximize their surplus.

The maximization of the N-EIIs' surplus is identical to the one stated in the reference model. The equilibrium conditions are as in Appendix B.2:

$$\mathbf{Max} \quad \int_0^{d_i^{t,2}} P_i^{t,2}(\xi)d\xi - p_i^t \cdot d_i^{t,2} \tag{52}$$

which gives the following KKT condition:

$$p_i^{t,2} = \mathrm{a}_i^{t,2} - \mathrm{b}_i^{t,2} \cdot d_i^{t,2} \quad \forall\, t, i \tag{53}$$

The optimization of the EIIs' surplus is written as:

$$\mathbf{Max} \quad \int_0^{d_i^1} P_i^1(\xi)d\xi - p^1 \cdot d_i^1 \tag{54}$$

that in KKT form is:

$$p^1 = \mathrm{a}_i^1 - \mathrm{b}_i^1 \cdot d_i^1 \quad \forall\, i \tag{55}$$

Note that in this case, we do not need to impose the equality of the hourly summer and winter EIIs' consumption, because by construction we drop the time dependence. Again, $d_i^{t,2}$ and d_i^1 are supposed to be positive.

(vi) Clearing of the energy market

There are now two separate energy markets, namely the one of the N-EIIs and the one of the EIIs. The clearing of the N-EII market takes place at the hub.

$$\sum_{f,i} g_{f,i}^{t,2} - \sum_i d_i^{t,2} = 0 \;\; (phub^{t,2}) \quad \forall\, t \tag{56}$$

Again the congestion charges are added to the hub price $phub^{t,2}$ to compute the marginal electricity prices in:

$$p_i^{t,2} = phub^{t,2} + \left(\sum_l (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot \mathrm{PTDF}_{l,i} \right) \quad \forall\, t, i$$

The clearing of the EII energy market requires to compute the average generation, emission and transmission prices to that market. This is expressed by relations:

$$pprod^1 = \frac{\left(\sum_{f,i,m}(gp^1_{f,i,m} \cdot (\text{cost}_{f,i,m} + \text{em}_m \cdot \lambda) \cdot 8{,}760)\right) + \sum_{f,i,m} \text{FC}_{f,i,m} \cdot G^1_{f,i,m}}{\sum_i d^1_i \cdot 8{,}760} \tag{57}$$

$$ptrans^1 = \frac{\left(\sum_{l,i} \text{PTDF}_{l,i} \cdot (\sum_f g^1_{f,i} - d^1_i) \cdot 8{,}760 \cdot \sum_t (\mu^{t,+}_l - \mu^{t,-}_l) \cdot \text{proportion}^t\right)}{\sum_i d^1_i \cdot 8{,}760} \tag{58}$$

$$p^1 = pprod^1 + ptrans^1 \tag{59}$$

This price appears in (55). We recall that, like in the regional average cost case, the EIIs' energy market clearing is given by:

$$\sum_{f,i} g^1_{f,i} - \sum_i d^1_i = 0 \;\; (\beta^1)$$

where in this case, β_i depends on i since we have regional markets.

(vii) Clearing of the emission market.

The emission constraint (60) slightly changes with respect to reference model in Appendix B.2. This is a direct implication of the market segmentation introduced to accommodate the two pricing regimes. However, the structure of this relation remains unchanged.

$$0 \leq \text{CAP} - \left(\sum_{f,i,m} \text{em}_m \cdot gp^1_{f,i,m} \cdot 8{,}760 + \sum_{t,f,i,m} \text{em}_m \cdot gp^{t,2}_{f,i,m} \cdot \text{hour}^t\right) \perp \lambda \geq 0 \tag{60}$$

Appendix C.2. Zonal average cost pricing model

We now modify the regional average cost pricing model by assuming that EIIs conclude special contracts with local producers. We obtain a new price formation reflecting zonal average costs. Because we assume that EIIs are supplied only with electricity produced by local power plants dedicated to them, there is no need to import electricity to satisfy the internal industrial demand. EIIs therefore no longer incur cross zone transmission costs. Again, we begin with the TSOs' model.

(i) The TSOs' model: clearing of the transmission market.

TSOs no longer have to accommodate the EIIs' demand which are now satisfied by local generation. These therefore disappear from the complementarity conditions (28) and (29) of the TSOs problem in Appendix C.1, which boils down to:

$$0 \leq \text{Linecap}_l - \left(\sum_i \text{PTDF}_{l,i} \cdot \left(\sum_f g^{t,2}_{f,i} - d^{t,2}_i\right)\right) \perp \mu^{t,+}_l \geq 0 \quad \forall\, t, l \tag{61}$$

$$0 \leq \text{Linecap}_l + \left(\sum_i \text{PTDF}_{l,i} \cdot \left(\sum_f g^{t,2}_{f,i} - d^{t,2}_i\right)\right) \perp \mu^{t,-}_l \geq 0 \quad \forall\, t, l \tag{62}$$

(ii) Generators maximize profit on the N-EII market segment

This model and the corresponding complementarity conditions are identical to those of Subsection (ii) of Appendix C.1.

(iii) Generators minimize their generation, emission and transmission costs of supplying the EII segment

The regional cost minimization problem of Appendix C.1 is replaced by a set of zonal cost minimization problems stated as follows. For each i:

$$\textbf{Min} \quad \sum_{i,m}(\text{cost}_{f,i,m} + \text{em}_m \cdot \lambda) \cdot gp^1_{f,i,m} \tag{63}$$

s.t.

$$0 \leq \sum_m gp^1_{f,i,m} - g^1_{f,i} \qquad (\eta^1_{f,i}) \quad \forall\ f, i \tag{64}$$

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \qquad (\nu^1_{f,i,m}) \quad \forall\ f, i, m \tag{65}$$

$$\sum_f g^1_{f,i} - d^1_i = 0 \ \ (\beta^1_i) \quad \forall\ i \tag{66}$$

$$0 \leq g^1_{f,i} \quad \forall\ f, i \tag{67}$$

$$0 \leq gp^1_{f,i,m} \quad \forall\ f, i, m \tag{68}$$

The corresponding KKT conditions are then stated as follows:

$$0 \leq \eta^1_{f,i} - \beta^1_i \perp g^1_{f,i} \geq 0 \quad \forall\ f, i \tag{69}$$

$$0 \leq \text{cost}_{f,i,m} + \text{em}_m \cdot \lambda + \nu^1_{f,i,m} - \eta^1_{f,i} \perp gp^1_{f,i,m} \geq 0 \quad \forall\ f, i, m \tag{70}$$

$$0 \leq \sum_m gp^1_{f,i,m} - g^1_{f,i} \perp \eta^1_{f,i} \geq 0 \quad \forall\ f, i \tag{71}$$

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \perp \nu^1_{f,i,m} \geq 0 \quad \forall\ f, i, m \tag{72}$$

Again, β^1_i is the internal transfer price which effectively ensures the right operations of the generation plants for EIIs in each zone. Our empirical tests show that β^1_i and the weighted (by period duration) average values of $p^{t,2}_i$ are identical (see Table 12). This equality between the virtual transfer price β^1_i and $p^{t,2}_i$ paid by the N-EIIs confirms the efficiency of the allocation of capacity between the two consumer sectors.

(iv) Generators allocate their capacity efficiently between N-EII and EII market segments.

This part of the model is unchanged with respect to Subsection (iv) of Appendix C.1.

Table 12 Comparison between weighted average $p_i^{t,2}$ and β_i^1

€/MWh	$p_i^{t,2}$	β_i^1
Germany	50.63	50.63
France	54.01	54.01
Merchtem	52.43	52.43
Gramme	52.59	52.59
Krimpen	51.99	51.99
Maastricth	51.94	51.94
Zwolle	51.63	51.63

(v) N-EIIs and EIIs maximize their surplus

The N-EIIs' maximization problem is identical to the one of Subsection (v) in Appendix C.1. The EIIs' model is subject to a minimal modification due to the different average cost pricing system adopted. The EIIs' optimization problem thus becomes:

$$\textbf{Max} \quad \int_0^{d_i^1} P_i^1(\xi)d\xi - p_i^1 \cdot d_i^1 \tag{73}$$

that in KKT form is:

$$p_i^1 = \mathrm{a}_i^1 - \mathrm{b}_i^1 \cdot d_i^1 \quad \forall\, i \tag{74}$$

where p_i^1 is the zonal average cost price and d_i^1 the EIIs' positive consumption level.

(vi) Clearing of the energy market

There are $|I| + 1$ energy market where $|I|$ is the cardinality of the set I. There is indeed one N-EIIs' market and one EIIs' market for each zone. The clearing of the N-EIIs' energy market is unchanged, while the clearing of the EIIs' energy market is modified as follows and holds for each i:

$$p_i^1 = \frac{\left(\sum_{f,m}\left(gp^1_{f,i,m} \cdot (\mathrm{cost}_{f,i,m} + \mathrm{em}_m \cdot \lambda) \cdot 8,760\right)\right) + \sum_{f,m} \mathrm{FC}_{f,i,m} \cdot G^1_{f,i,m}}{d_i^1 \cdot 8,760} \quad \forall\, i \tag{75}$$

(vii) Clearing of the emission market.

The clearing of the emission market is as in Subsection (vii) of Appendix C.1.

Appendix D. Computational issues related to the average cost price models

The reference models are convex and have one global solution. The introduction of the average cost based contracts may lead to some computational difficulties since the averaging process ruins the convexity properties of the model.

Table 13 EIIs and N-EIIs' reference demand in MWh

Zones	Reference demand			
	Summer		Winter	
	EIIs	N-EIIs	EIIs	N-EIIs
Germany	29,655	18,980	29,655	48,835
France	18,527	20,323	18,527	45,373
Merchtem	4,306	1,310	4,306	4,580
Gramme	1,851	560	1,851	1,960
Krimpen	3,168	2,950	3,168	7,469
Maastricht	1,082	703	1,082	1,810
Zwolle	1,941	1,169	1,941	3,033

In our analysis, we introduce both a regional and a zonal average cost pricing mechanisms characterized by different complexity. In particular, the regional average transmission cost is based on a product of primal ($g^1_{f,i}$, $d^1_{f,i}$) and dual ($\mu^{t,+}_l$, $\mu^{t,-}_l$) variables [see condition (58)], while the zonal average cost price accounts only for primal variables. This makes the regional average cost model more complex than the zonal one.

Generally a non-convex problem may have a multiplicity of solutions or no solution. Our simulations show that all models are feasible. However, we notice some strange behaviour in the capacity allocation. The different allocation strategies adopted between the two Belgian zones in the zonal average cost model may be an example of this nonconvexity effect.

Appendix E. Input data

Table 13 introduces the reference demand values by period and consumer group. Our computations are based on public data that are available on Eurostat and UCTE websites (see Eurostat 2005; UCTE 2005a,b). Table 14 shows the allocation of the available capacity that is computed on the basis of the availability factors reported in Table 15. Hydro availability factors differ over zones. They are: 32.4% in Germany, 28.9% in France, 12.3% in Belgium and 0% in the Netherlands. We used public data provided by Eurostat and UCTE to compute them (see Eurostat 2005; UCTE 2005a,b).

Table 15 also reports the emission rates (see Davis and URS Corporation 2003 for more details). The marginal fuel costs are computed taking into account the efficiency factor of each technology. They are based on public data.[24] In particular, we set the efficiency rates of lignite/coal and CCGT plants, respectively at 37 and 49% as in Smeers 2007.

Table 16 lists the amount of emission allowances that generators hold. In sum, they correspond to the emission cap of the power sector. As reference, we took public

[24] Sources: IEA, *Weighted Average CIF Cost of Crude Oil*, IEA Annual Statistical Supplement for 2005, released August, 25 2006; www.bafa.de/1/de/service/statistiken/kraftwerkssteinkohle.php; EWI/Prognos – Studie: Die Entwicklung der Energiemärkte bis zum Jahr 2030.

Table 14 MW of available capacity by zones

Available capacity							
Technology	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	1,505	6,804		13			
Renewable	4,583	1	20.43	21.32	101.26	101.26	102
Nuclear	15,007	45,369	2,078	2,204	337		
Lignite	17,783	77					
Coal	24,613	8,824	1,564	979	3,128		482
CCGT	13,544	8,164	2,589	1,207	4,432	2,917	4,834
Other-gas	2,147	256	194	170	833		
Oil-based		4,760	55	194			
Total	79,183	73,535	6,500	4,788	8,831	3,018	5,417

Table 15 Emission factors (ton/MWh), fuel costs (€/MWhe) and availability factors by technology

Technology	Emission factors	Fuel costs	Plant availability (%)
Hydro	0	0.00	Different
Renewable	0	0.00	25
Nuclear	0	4.50	75
Lignite	0.97	14.86	85
Coal	0.9542	21.62	80
CCGT	0.432	36.35–37.08	85
Other-gas	0.6266	54.92–55.20	85
Oil-based	0.8441	46.9–67.62	85

Table 16 NAPs by generator and country

Ton p.a.	Germany	France	Belgium	Netherlands	Total
EoN	35,798,149			7,698,528	43,496,677
Electrabel	351,107		9,296,495	7,749,596	17,397,198
Edf		23,540,828			23,540,828
EnBW	10,302,328				10,302,328
Essent				9,909,033	9,909,033
Nuon				9,109,160	9,109,160
RWE	112,482,413				112,482,413
Vattenfall	77,003,200				77,003,200
Fringe	72,384,875	11,709,252	5,764,115	4,283,146	94,141,388
Total	308,322,072	35,250,080	15,060,610	38,749,463	397,382,225

figures available on the European Commission website (European Commission 2006; Community Independent Transaction Log 2006).

Finally, Table 17 shows the hourly fixed costs included in the average cost pricing models. They are classified by zone and technology. In accordance with our input data

Table 17 Hourly fixed costs by zone and technology

€/MWh	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	55.71	55.71		55.71			
Renewable	46.07	41.93	41.93	41.93	86.81	86.81	86.81
Nuclear	14.68	12.89	12.89	12.89	17.76		
Lignite	12.55	11.03					
Coal	12.55	11.03	12.55	12.55	12.55		12.55
CCGT	4.16	4.96	7.93	7.93	8.53	8.53	8.53
Other-gas	4.16	4.95	7.92	7.92	8.52		
Oil-based		4.96	7.93	7.93			

(IEA 2005), renewable technologies are more expensive in the Netherlands than in the other countries, where generators receive subsidies to build renewable plants.

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