2008/62

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Average power contracts can mitigate carbon leakage

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CORE DISCUSSION PAPER
2008/62

Average power contracts can mitigate carbon leakage

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November 2008

Abstract

The progressive relocation of part of the Energy Intensive Industries (EIIs) out of Europe is one of the possible consequences of the combination of emission charges and higher electricity prices entailed by the EU-Emission Trading Scheme (EU-ETS). In order to mitigate this effect, EIIs have asked for special power contracts whereby they would be supplied from dedicated power capacities at average (capacity, fuel, transmission and emission allowance) costs. We model this situation on a prototype power system calibrated on four countries of Central Western Europe. In order to capture the main feature of EIIs' demand, we separate the consumer market in two segments: EIIs and the rest. EIIs buy electricity at average cost price while the rest pays marginal cost. We consider two different types of EIIs' contractual arrangements: a single region wide and zonal average cost prices. We also analyze the cases where generators only rely on existing capacities or can invest in new ones. We find that these average cost contracts can indeed partially mitigate the incentive to relocate activities but with quite diverse regional impacts depending on different national power policies. Models are formulated as a non-monotone complementarity problems with endogenous energy, transmission and allowance prices and are implemented in GAMS.

Keywords: average cost based contracts, carbon leakage, complementarity conditions, EU-ETS.

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This work has been financially supported by the Italian project PRIN 2006, *Generalized monotonicity: models and applications* whose national responsible is Prof. Elisabetta Allevi and by the Chair Lhoist Berghmans in Environmental Economics and Management. The authors gratefully acknowledge Thierry Bréchet, Andreas Ehrenmann and Chefi Triki for their in depth comments and helpful advices.

This paper presents research results of the Belgian Program on Interuniversity Poles of Attraction initiated by the Belgian State, Prime Minister's Office, Science Policy Programming. The scientific responsibility is assumed by the authors.

1 Introduction

Climate change is a global issue but the mitigation of its development and extent is still seen as a regional matter that can be handled by a diversity of means decided at local level (see the argument of Pizer [15]). The EU, with its Emission Trading Scheme (EU-ETS or more briefly ETS), has taken the lead in this endeavour, possibly at the risk of endangering the competitiveness of part of its industry. The ETS is a cap and trade system that introduces a price for each unit of GHG emitted by the combustion installations covered by the scheme. This creates costs, both direct and indirect, for the companies operating these installations. The direct costs (hereafter carbon cost) accrue from the obligation to either buy allowances or reduce emissions. The indirect cost (hereafter electricity cost) is due to the higher price of electricity that results from the pass-through of allowance (opportunity) costs in the price of electricity. Both add up and modify the operations costs of the affected Energy Intensive Industries (hereafter EIIs). This impact depends on the industrial sector and may be important for some of the EIIs covered by the ETS.

EIIs have argued that the ETS endangers their competitive positions with respect to companies of the same sectors located in environmentally less restrictive countries. They also explain that they will relocate some or all of their activities in these countries in order to protect their competitiveness. This would reduce emissions in Europe but increase them outside of the EU. This would result in no environmental benefit but could cost Europe significant economic and job losses. The expression "carbon-leakage" refers to this relocation of economic activity and emissions.

The impact of the ETS on industrial activity depends on several factors, among them (i) the industry's ability to pass the extra carbon cost onto the final consumer, (ii) the openness of international trade (iii) the energy intensity of the sector and its capability to abate carbon, (iv) the allowance allocation method and (v) the product specialization. These different factors combine to determine whether the sector is largely exposed to international competition or protected. Service oriented economies will obviously suffer less from the ETS than those that heavily rely on highly emitting technologies. Delgado [3] elaborates on the comparatively large part of energy intensive goods in EU export, a phenomenon that is obviously worrying for a region that intends to take the lead in abatement measures.

Opinions diverge on the importance of carbon leakage. The "Climate Strategy group" (Hourcade et al. [9]) plays down the danger for Europe. The authors explain that iron and steel, aluminium, cement and lime are the only sectors that can be affected by the ETS; they study the UK where these sectors altogether represent only 1% of GNP and conclude that the problem is minor and particular solutions can probably be found. The proposal for border adjustment defended by the French government during its presidency of the EU suggests a less optimistic view. The idea of the border adjustment is to counter carbon leakage by supporting exports by EU industries affected by carbon leakage and taxing those goods imported from countries with a more lenient environmental system. This proposal clearly acknowledges a problem of competitiveness due to carbon leakage. The European Commission does not discard this possibility either. Its "Impact Assessment"[1] admits "until a comprehensive international agreement would be reached, carbon leakage could occur undermining the overall environmental objective of EU climate and energy policies". The need to protect

[1] See *Impact Assessment*, document accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020, Brussels, January 23, 2008. Available at *http://ec.europa.eu/environment/climat/climate_action.htm*.

the competitive position of the EU industry has accordingly been taken into account in the design of the proposal of the ETS Directive for the period 2013-2020. Specifically, point 8 of Article 10a of the Directive proposal states that "in 2013 and in each subsequent year up to 2020, installations in sectors, which are exposed to a significant risk of carbon leakage shall be allocated allowances free of charge up to 100 percent of the quantity determined in accordance with paragraphs 2 to 6"[2]. This measure will be adopted in case of failure of international environmental negotiation whose conclusions is foreseen by the year 2011.

Not unexpectedly, representative of the EIIs are most vocal about the impact of the ETS on their costs. Their position should not necessarily be seen as pure lobbying. These sectors generally consist of multinational companies that operate worldwide and hence could relocate part of their production without suffering dramatic economic losses themselves. They would incur transient costs but no long-term damage; their message can plausibly be interpreted as advising that European economies and populations, not the firms themselves, would loose a great deal in the long run.

EIIs have proposed two remedies. One is to introduce sectorial agreements whereby firms of a given sector would agree to reduce emissions. This has so far not materialized. EIIs also proposed another measure that today has seen two example of implementation. EIIs have indeed argued about carbon leakage to demand special electricity contracts to counter the impact of the ETS on electricity price. The objective of these contracts is to isolate EIIs from the joint effect of passing the ETS emission allowance (opportunity) costs in electricity prices in carbon dominated systems, and aligning European electricity prices on these carbon inclusive prices because of the progressive integration of the electricity market. Specifically the Finnish pulp and paper industry has succeeded to obtain such a contract with the fifth nuclear power plant that the Franco-German consortium formed by Areva and Siemens is building at Olkiluoto on the western coast of Finland[3]. This principle also underlines in the formation of the Exeltium consortium in France where a number of electro-intensive industries[4] have managed to conclude long term contracts with EdF[5]. In both cases, long term competitiveness and price stability are the arguments invoked to justify these contracts.

This paper is about these contracts: we introduce these special contracts in a prototype model of the European power sector and provide a first assessment of their impact on investments in the power sector and their capability to mitigate the impact of the ETS on EIIs.

An in-depth study of the true impact of special contracts such as those implied in Exeltium is probably impossible today. A major difficulty is the lack of adequate information on the reaction of the EIIs to changes of carbon and electricity prices: we know that the ETS affects these sectors but we are currently unable (from outside the industry) to quantify the impact of carbon and electricity prices on their activities. But the situation is temporary; pieces of information are progressively collected and knowledge is progressively accumulating. We

[2]Source:http://ec.europa.eu/environment/climat/emission/pdf/ets_revision_proposal.pdf.

[3]Sources: http://virtual.finland.fi/netcomm/news/showarticle.asp?intNWSAID=28308 and http://virtual.finland.fi/netcomm/news/showarticle.asp?intNWSAID=25870.

[4]These are: Air Liquide, Alacan, Arcelor Mittal, Arkema, Rhodia, Solvay and UPM-Kymmene.

[5]After negotiations lasted almost three years, EdF and Exeltium have finalized their partnership agreement following the initiative launched by the government in 2005. With this agreement, industrial consumers who are Exeltium shareholders are securing part of their electricity supply over the long term. EdF is optimizing the use of its production facilities by supplying around 13 TWh per year, over a total of 24 years (see EdF press release at http://www.edf.fr/the-edf-group/press/press-releases/noeud-communiques-et-dossier-de-presse/edf-group-and-exeltium-finalise-partnership-agreement-600379.html).

already mentioned the analysis conducted by the Climate Strategy group on the basis of the UK. It would be interesting to know whether similar industrial structures apply throughout the EU or will eventually apply as industrial activities move to emerging economies (McKinsey&Company [10]). Short-term Armington elasticity, such found in (Hourcade et al. [9]), cannot provide the basis for long- term substitution analysis but process models such as those presented by Hidalgo et al. [8] and Szabò et al. [16] can. Also IEA is conducting an in depth question of this problem. An other difficulty, probably much less pressing, is the insufficient development of our European power models. The sector is central to the problem of carbon leakage and the EIIs, but its representation cannot be limited to the sole generation side. The spatial arrangement and hence the representation of the grid are central for responding to the EIIs' question for special contracts. Even though power models that involve a representation of the grid are not numerous, they are progressively emerging. We use a prototype model here but mention current activities such as Duthaler et al. [6], Perekhodtsev [14] and Zhou and Bialek [17].

This paper takes stock of this emerging activity and provides a prototype study of the impact of special contracts such as those implied by Exeltium, possibly combined with free allowances as foreseen by the Commission's proposals. The paper is organised as follows: Section 2 describes the principle of the special contracts demanded by EIIs. Section 3 presents our methodology and Section 4 is devoted to the models and input data. Sections 5, 6 and 7 explain the main results and Section 8 concludes. The model used is described in Oggioni and Smeers [12],[13].

2 Cost Based Electricity Contracts

Investments in both EIIs and the power sectors are capital intensive and long term. As discussed in the introduction, schemes such as the ETS affect these investments in at least two ways. By imposing the covered EIIs an obligation either to abate or surrender an emission allowance per ton of emitted CO_2 equivalent, the ETS directly increases the production cost of the firms in these industries. By imposing a similar obligation to the power sector, the ETS also entails an increase of the price of electricity and hence further raises the production cost of the EIIs. These two phenomena come on top of a general evolution that sees a progressive movement of large energy consuming industries away from developed to emerging economies (McKinsey&Company [10]). New investments of EIIs in Europe, which may already be questioned in the current economic conditions are then becoming more at risk as a result of this double cost effect. Recall that this risk is incurred without any environmental benefit in a carbon leakage context: emissions are not reduced but simply displaced from Europe to other places of the world. Emissions will even probably increase to the extent that the displaced installations connect to less carbon efficient power systems. This relocation of industrial consumption introduces a demand risk that adds to the already uncertain environment that surrounds investments in the power sector.

Contracts that guarantee the delivery of electricity on the long run (e.g. 15 years) at a controllable overall cost, possibly backed by dedicated capacities, can mitigate that risk and reduce the cost, benefiting both EIIs and the power sector. The principle of these contracts is straightforward even if their implementation may be complex: an energy intensive consumer procures electricity forward over a long period by essentially paying its full cost (investment and operations) independently of the vagaries of the prices on power exchanges.

This contact is normally for high load electricity, corresponding to a base activity of the electricity consuming EII firms. It is thus associated to a base load unit, which, because of its high capital cost is more risky to invest in without a long term guarantee of delivery even if it is cheaper to operate. The electricity price contains a fixed part corresponding to the investment cost. It may contain a variable fuel part, which is in any case a world price (coal or nuclear fuel). If fossil fuel based, the electricity price would also contain a CO_2 contribution. The principle of the cost based contract is that this CO_2 contribution would be paid at average cost and not according to a marginal cost principle that EIIs object to. EIIs argue that marginal cost pricing increases electricity prices and they advocate a return to average cost pricing. As in the Finnish and the Exeltium consortium cases, EIIs ask for these cost based electricity contracts, possibly backed by dedicated facilities.

3 Methodology

3.1 Model Description

The problem of the possible impact of the ETS on EII sectors is long term. We accordingly cast average cost power contracts in a model that can accommodate, at least partially in this paper, investments in new capacities. In order to do so, we construct a power model (see Oggioni and Smeers [12], [13]) where demand is decomposed into two segments; one segment consists of the firms of the covered EII sectors (EIIs hereafter), the other segment gathers the rest of the demand (N-EIIs hereafter). The power sector is represented by a process model where the different generation plants are explicitly described on a technological basis [6]. These models are well mastered both in the literature and in practice and the representation adopted in this paper is standard. The demand sectors are described differently. We classically model the N-EIIs' sector by a demand function. We would also ideally adopt a process model for describing the EIIs, but even though these exist for the cement and steel sectors (see Demailly and Quirion [4], Hidalgo et al. [8] and Szabò et al. [16]), they are far from standard today. One can also note that while GHG studies extensively rely on power sector models, they generally adopt a much simpler description of the consuming sectors. We follow suit and simplify the description of the EIIs into a linear demand function that that we calibrate on the basis of Newbery [11]. This modelling of the EII sectors implies that we interpret a reduction of their demand as a relocation of activities that measures the carbon leakage effect. This is admittedly a rough representation of the reaction of these industries as it does not differentiate between activity relocation and energy efficiency improvements. Still it suffices to qualitatively capture the impact of the ETS on EIIs. We shall show that it also allows one to represent both the carbon and the electricity costs and hence permits differentiating between different policies of free permits allocations to the energy consuming sectors.

Throughout the paper we make the blanket assumption that all agents are price takers or alternatively that large energy consumers can impose average cost pricing on generators (or that they can build their own units and hence procure electricity at average cost). We justify the assumption as follows. While it is apparently easy to find evidence of the exercise of market power by generators, the literature shows that it is equally easy to criticize this evidence. Moreover there is no well admitted paradigm for modeling the exercise of market power by generators (Cournot is technically simple and supply functions difficult; but none of them is substantiated by convincing empirical evidence). Introducing market power is thus

[6] Different type of generation units with their technological characteristics.

a somewhat arbitrary exercise outside studies that explicitly aim at measuring its exercise. Note that this blanket assumption does no imply that all models presented here are of the perfect competition type as average cost pricing deviates from the long run marginal cost pricing which would be the rule in perfect competition. Last we mention that our models always account for the emissions of the power sector, and in some version (see infra) also for the emissions of the EIIs. Emissions are capped, which implies that the price of CO_2 is endogenous.

Transmission is represented according to a flowgate model which is the approach currently discussed for CWE by transmission system operators. This network model is well known in the literature[7]. The representation includes a node, the so–called hub node, where electricity asks and bids converge and clear. The hub can be considered as a virtual market that sets the electricity price. In this system, generators send the electricity they produce to the hub where energy is withdrawn and delivered to consumers located in the different nodes. Power trade must respect the capacity limit of the lines composing the grid. A Power Transfer Distribution Factor $PTDF$ matrix determines both the directions and the proportions of power flowing through network lines as a function of nodal injections and withdrawals. Constraints impose that the sum over all nodes of the proportion of the net power flow injected into and withdrawn from all nodes and passing through a network line to reach the hub must be lower than the capacity of the line used to transfer electricity. This limits the set of possible injections and withdrawals. Congestion arises when at least one of the grid lines is overloaded. National Transmission System Operators (TSO hereafter) are in charge of relieving the network congestion and their operating costs are paid by final electricity consumers. Congestion costs are added to the electricity price set at the hub and differ with generators and consumers' locations in the network. We work with a zonal representation of the grid that therefore implies a zonal pricing system.

3.2 Analysis Structure

We consider three views of the problem of increasing technical complexity and discuss results in Sections 5, 6 and 7 respectively. The first two views (hereafter referred to as "IFC" (Indirect ETS costs with Fixed Capacity) and "II" (Indirect ETS costs with Investments) respectively) concentrate on the pass-through of allowance prices in electricity prices (the electricity cost). The first version of the problems (IFC) assumes fixed generating capacities, the second one (II) allows for possible investments. The latter cases (II) are obviously more realistic, but we also retain the simpler fixed capacity (IFC) cases because they allow for a first, simpler, presentation of the phenomena. Both views of the problem are constructed by assuming an emission cap for the sole power sector, without any trade of allowances with the EIIs. The third view of the problem, hereafter referred to as "DII" (Direct and Indirect ETS costs), additionally deals with the carbon effect, that is the net effect for EIIs of trading allowances on the market, taking into account their emissions and the allowances that they receive free. We cast both the carbon and electricity costs in the electricity demand function of EIIs. The industrial electricity consumption is then affected by two factors: the electricity price, which embeds the "electricity cost" and a carbon component which is the "carbon cost" and reflects the EIIs' position on the emission market. In this latter view of the problem (DII) we also modify the emission constraint in order to account for the emissions deriving from the industrial production activities.

[7]See the section on flowgate on the HEPG website.

These different view of the carbon leakage problem, considering first the increase of electricity prices (IFC and II models) and then the combination of both this increase and the trading of allowances by EIIs (DII) is also quite in line with practice as representatives of the EIIs mainly complained about high electricity prices during the first compliance period of the ETS.

Each of these three views of the carbon leakage problem in turn gives rise to four models that we respectively note by NETS_R, ETS_R, ETS_SAC and ETS_ZAC. The first model (NETS_R) adopts the perfect competition paradigm in the sense that the two demand segments pay an identical electricity price that is equal to the marginal production cost of the unit that is highest in the merit order. It also supposes that there is no ETS. The second model (ETS_R) works under the same perfect competition scenario, but assumes that the ETS is in force. We introduce these cases both for reference and calibration purposes. The perfect competition paradigm under the ETS indeed includes a full pass-through of the marginal (opportunity) cost of allowances in the price of electricity, independently of the procurement of these allowances by power companies. This is the situation that EIIs complain about when they refer to the windfall profits of the power companies that pass in the electricity price the allowances that they partially received free. In order to introduce the cost based electricity contracts, we modify this reference model by splitting the capacity in two parts endogenously dedicated to each market segment. Generators then adapt their generation mix to the pricing scheme in each market segment. N-EIIs face the marginal cost price of their dedicated capacities that adapt to their time varying demand. EIIs benefit from the average cost contracts suited to their high load demand. We then consider two different average cost contracts respectively identified by ETS_SAC and ETS_ZAC that reflect prevailing and possibly forthcoming conditions in the European electricity market. The first pricing scheme is regional and referred to as ETS_SAC. It assumes that the transmission system has developed to a stage that EIIs can and do procure electricity on a regional basis. The region in this case is Central West Europe, hereafter CWE (see ECN [7]); it consists of Belgium, France, Germany and the Netherlands. All EII firms in the the region pay the same average cost that includes the full generation cost (capacity, fixed and variable operating, fuel and CO_2 costs) of the dedicated capacities and the transmission cost (congestion charges) from generation to EII consumers. The latter is computed according to a flowgate model mentioned above. The case law of European competition authorities considers that this regional market is not established yet. The second pricing scheme takes stock of this jurisprudence and supposes that EII firms procure electricity at average cost on a local, here zonal basis, hereafter referred to as ETS_ZAC. This average cost then boils down to the full average generation cost (capacity, fixed and variable operating, fuel and CO_2 costs) of the dedicated capacities of the zone, without any transmission component. Both ETS_SAC and ETS_ZAC models are inspired by the approach followed by French EIIs when constituting the Exeltium consortium in order to buy electricity from generators at a French market-wide full cost based price. The two average cost pricing schemes, ETS_SAC and ETS_ZAC, considered here only differ by the regional scope of the consortium and the implication of the transmission component on the average cost price. Finally, we consider the so–called "EIINA" and "EIIA" scenarios which respectively indicate the cases where EIIs do not receive and receive free allowance when they participate to the emission market.

N-EIIs and EIIs' fuel costs, capacity costs and reference demands are identical throughout the three views. This allows us to examine the evolution of results under different organizational scenarios without data playing an impact on the results. This step by step methodology

also allows us to analyze the EIIs' problem under progressively more complex aspects. Note that the structure of the average cost price models is such that generators are constrained to conclude average cost based contracts with EII companies which in turn can exercise monopsony power since have access to dedicated power. An interesting question is whether power companies effectively gain from the application of these long term contracts. This is reported in the welfare analysis. We summarizes the overall structure of the analysis and the different models and their nomenclature in Table 1.

	Models			
Analysis Steps			**Leakage Mitigation Scenarios**	
IFC	NETS_R	ETS_R	ETS_SAC	ETS_ZAC
II	NETS_R	ETS_R	ETS_SAC	ETS_ZAC
DII	EIINA_NETS_R	EIINA_ETS_R	EIINA_ETS_SAC	EIINA _ETS_ZAC
	EIIA_NETS_R	EIIA_ETS_R	EIIA_ETS_SAC	EIIA_ETS_ZAC

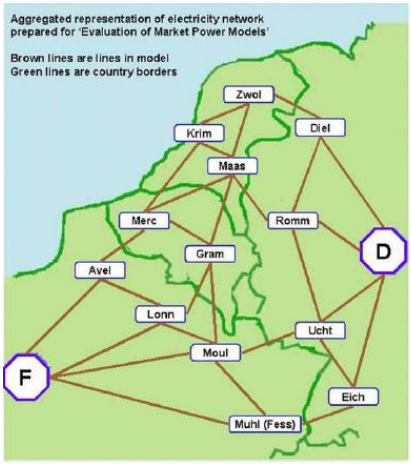
Table 1: Analysis Steps and Scenarios

4 Model Setting

The analysis is applied to a stylized representation of the Central Western European (CWE) power market depicted in Figure 1. Data of this model are available on the Energy Research Center of the Netherlands (ECN [7]) website. We also calibrate the rest of the model for the year 2005 which saw the inception of the ETS and is also the first year for which emissions are recognized to be independently and consistently verified.

The power market depicted in Figure 1 comprises fifteen nodes distributed over four countries: Germany, France, Belgium and the Netherlands. Electricity production and consumption activities are aggregated in seven nodes: 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 French nodes are passive and are only used to transfer electricity. Nodes are connected by 28 flowgates with limited capacity. There are 10 cross-border flowgates: two connect Germany and the Netherlands and three link the Netherlands and Belgium; there are three lines between Belgium and France and two between France to Germany. The model of the grid follows the standard DC load flow approximation: flowgates are characterized by limited transfer capacities, which constrain power flows, and by Power Transmission Distribution Factors ($PTDF$) that distribute injection and withdrawals of electricity along the lines. These data (see ECN [7]) are reported in Figure 1. The big German node is the hub node where all power asks and bids converge and define the system electricity price.

As foreseen by the FlowBased Market Coupling project of the CWE's electricity systems, the clearing of this market results from an interaction between the PXs and the TSOs of the region that can be assimilated to the solution of a consumer and producer surplus maximization in CWE subject to transmission constraints. The system currently operates on three countries only (the above minus Germany) and still uses a representation of the grid by transmission capacities. It should include Germany and move to the flow based representation of the grid soon. We anticipate this evolution and directly adopt the flow based, or flowgate representation of the grid. This system introduces a market of transmission rights that agents pay for to the Transmission System Operators.



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

Figure 1: Central Western European market and network line capacities

We assume eight European power companies[8] plus a fringe which assembles the remaining small generators. These companies supply this market by running eight different technologies: hydro, renewable, nuclear, lignite, coal, CCGT, old gas and oil based plants. These units are ranked in merit order that is endogenously determined as a function of the (exogenous) fuel prices and the (endogenous) transmission constraints. This assumption implies a staircase representation of the supply curves whose shape is directly influenced by the marginal costs of the different technologies. Plant capacities' values are taken from the public 2005 reports of the power companies included in the models.

Depending on the view of the problem (see Section 3), electricity is produced either by existing or new power plants. In order to simplify both the database and the interpretation of the results, we assume that old and new capacities have identical variable and fixed costs. The models obviously allows one to change this assumption and apply different efficiency rates to new plants. Doing so in this prototype study would however cloud the results that would then be influenced by both fundamental economic phenomena and sometimes arbitrary data differentiations.

Generators supply both EIIs and N-EIIs. For reasons explained in Section 3, it is currently quite difficult to resort to sectorial models of the EIIs sectors, whether process or econometric models. We use linear demand functions to describe these two consumer groups. We construct them by setting a reference power price of 40 €/MWh and reference elasticity values of -0.1 and -1 respectively for N-EIIs and EIIs. As already said, the -1 value is taken from Newbery [11]. This elasticity's assumption may appear too high, but our goal is to get insight into the way cost based contracts mitigate the EIIs' difficulties. We are not in a position in this paper to come up with a precise quantification of these effects[9].

The period analyzed is one year composed of 8760 hours subdivided into two sub-periods: the so–called summer (5136 hours) and winter (3624 hours). We are thus effectively working with the base-load demand of each consumer group in winter and in summer. We differentiate this based load demand by node. We suppose, as is the case in CWE, that N-EIIs have a

[8]EdF, Electrabel, E.ON Energie AG, ENBW Energieversorgung Baden-Württemberg, Essent Energie Productie BV, Nuon, RWE Energie AG and Vattenfall Europe.

[9]Nevertheless, we also tested the case where the industrial demand elasticity equals -0.8 to verify the robustness of our results.

higher power demand in winter than in summer. EIIs' power demand is constant over the year.

After transmission rights and electricity, emission allowances constitute the third commodity exchanged on this market. The carbon market is simply modelled by an emission constraint where the total cap is computed on the basis of the data available from the Community Independent Transaction Log ([1]). We used the report by Davis and URS Corporation [2] as a reference for the emission factors of the different generation technologies. We explain the computation of EIIs' emission factors in Appendix G. We assume full auctioning of allowances to generators and a benchmarking method for allocating free allowances to EIIs.

We follow the structure of analysis introduced in Section 3 and accordingly first present the results of the models with fixed generation capacity. We later allow generators to invest in new power plants and finally consider the scenarios where EIIs are inserted in the ETS. In order to simplify the notation we do not refer to the section identifier (IFC, II, DII. See Table 1) when discussing results obtained under the assumptions of the section. Various appendices provide additional information. Oggioni and Smeers [12], [13] give the technical details of the model.

5 Indirect Electricity Cost with Fixed Capacity Scenarios (IFC)

Table 2 reports the global impact of the different policy scenarios on electricity demand, that we analyze in more details in this section.

TWh	**N-EIIs**	**EIIs**	**Total**
IFC_NETS_R	649	598	**1,248**
IFC_ETS_R	646	531	**1,177**
IFC_ETS_SAC	634	555	**1,189**
IFC_ETS_NAC	623	565	**1,188**

Table 2: EIIs' hourly demand without and with the EU-ETS

As announced, we drop the section' s identifier (here "IFC") when referring to scenarios conducted with fixed capacity.

5.1 Reference Case with (IFC_ETS_R) and without (IFC_NETS_R) ETS

The inception of the ETS emission trading globally decrease EIIs' electricity consumption from 598 TWh (NETS_R) to 531 TWh (ETS_R). N-EIIs' reduction is from 649 TWh to 646 TWh. The pricing effects leading to that reduction of demand are analyzed in Appendix B.1. The fall of EIIs' demand is significant but driven by our assumption of a long-term EIIs' price elasticity of -1 at the reference demand point of 40 €/MWh. It illustrates the EIIs' threat of a long-term relocation of some of their facilities outside of Europe and the carbon leakage that it implies. It also highlights the importance for Europeans of properly and rapidly assessing the effective reaction of the EIIs to the changing electricity price implied by the ETS.

The decreased electricity demand and the utilization of less polluting technologies also imply an emission reduction. There is a cut of CO_2 emissions from 464 Mio Ton before the inception of the ETS (NETS_R) to 397 Mio Ton (ETS_R) which is the cap imposed on the power sector in this stage of analysis. The allowance price amounts to 24.44 €/ton.

5.2 Regional (IFC_ETS_SAC) and Zonal (IFC_ETS_ZAC) price

Average cost pricing policies partially relieve EIIs' burden while maintaining the global emission target. On the positive side, both the regional (ETS_SAC) and the zonal (ETS_ZAC) prices increase EIIs' electricity consumptions compared to the reference marginal cost prices (ETS_R). The negative side is that not all EIIs benefit from the application of these pricing schemes and the final results depend on national energy policies. The increase of demand does not go as far as recovering the activity levels observed before the inception of the ETS.

The regional price (ETS_SAC) increases EIIs' consumption from 531 TWh to 555 TWh. EIIs enjoy lower electricity prices in Germany, the Netherlands and in the Belgian location Merchtem, which increase their activities. In contrast the single price policy increases EIIs power costs in France and the other Belgian node Gramme with a consequent decrease of their electricity consumption. The price increase is particularly high in France (+69%) where EIIs' electricity consumption falls from 218 TWh to 170 TWh. In Gramme, the decrease is just of 1% (from 17,2 TWh to 17 TWh). These EIIs' demand decreases are globally compensated by increases in other nodes, leading to the final aforementioned 5% augment of the EIIs' demand (Table 2).

The zonal price (ETS_ZAC) also has a global positive effect on EIIs. It increases their electricity consumption from 531 TWh to 565 TWh compared to marginal cost pricing (ETS_R) and with an increase from 555 TWh to 565 TWh does slightly better than the single price (ETS_SAC). But here again, this global positive effect results from quite different local impacts on EIIs. Nuclear capacity in France and in the Belgian node Gramme, combined with zonal pricing system drastically mitigates the EIIs' electricity costs in these locations. EIIs are supplied by local power plants in this regime and do not have to share cheap and clean electricity with foreign EIIs' plants as in the single price (ETS_SAC) scenario.

The situation of EIIs is more critical in countries where electricity is mostly produced by fossil technologies as in the Netherlands and the Belgian node Merchtem. Industries effectively suffer from the zonal price policy. In Germany, the industrial electricity consumption decreases from 270 TWh to 236 TWh with respect to the single price (ETS_SAC), but remains 7% higher than in the marginal cost pricing case (ETS_R) where the consumption level is 220 TWh.

This global improvement of the EIIs' situation resulting from an economically inefficient policy (average cost pricing) is to be paid somewhere. One indeed observes that the single and the zonal prices respectively decrease N-EIIs' electricity consumption from 646 TWh to 634 TWn (ETS_SAC) and from 646 TWh to 623 TWh (ETS_ZAC) compared to marignal cost pricing policy (ETS_R).

5.3 Welfare Analysis

The welfare analysis of Table 3 gives an alternative view of these results. The lines "EIIs", "N-EIIs" and "Consumers" are self-explanatory. The lines "Generators" and "Allowances" respectively report the generators' profits and the allowance values obtained by multiplying the market cap of 397 Mio ton p.a. by the allowance prices of the different scenarios (an allowance comes at 28.48 €/ton and at 28.21 €/ton in the regional (ETS_SAC) and zonal (ETS_ZAC) pricing systems. The generators' profits are computed assuming fully grandfathered allowances and hence are higher than before the inception of the ETS (NETS_R). Generators' profits decrease when allowances are totally or partially auctioned. In case of full auctioning the generators' profits are obtained by subtracting the allowance value from

the profit reported at the "Generators" line. Note that this profit representation allows us to evaluate the impacts of different proportions of free allocation on generators' profits. Finally, Table 3 lists the TSO' merchandising profits in the different cases. These profits accrue from the application of the flowgate model to manage the congestion of the transmission system.

Except for the single price scenario, (ETS_SAC), EIIs' surpluses evolve in parallel with electricity consumption. The decrease of EIIs' surplus in the regional price policy, notwithstanding the global consumption increase, results from the significant drop (-47%) of the French EIIs' surplus which is not compensated by increases in other nodes. Recall that French EIIs reduce their power demand by 22% in this regional price regime.

Billion €	**IFC_NETS_R**	**IFC_ETS_R**	**IFC_ETS_SAC**	**IFC_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**

Table 3: Welfare under Different Fixed Capacity Scenarios

6 ETS Induced Electricity Costs: Introducing Investments (II)

We adapt the preceding analysis to the case where generators can invest in all locations, subject however to national prohibitions and technological possibilities. Specifically, generators can build new nuclear power plants only in France, lignite is restricted to Germany and hydro power stations are not available in Belgium and in the Netherlands. Since investment is a long term phenomenon, we replace the 2005-2007 emission cap of the power market used with fixed capacities by the more restrictive CO_2 level allowed in the 2008-2012 ETS phase. In particular, we fix it to 359 Mio Ton p.a[10]. The rest of the model and the structure of the analysis remain unchanged. We first define reference investment scenarios with and without the emission constraint (II_ETS_R and II_NETS_R) and then apply the regional and zonal price (II_ETS_SAC and II_NETS_ZAC). As before we drop the section's identifier (here "II") when referring to scenarios conducted with investments.

The global impact of the different policies on electricity demand is given in Table 4.

One notes at the outset that investments increase electricity consumption with respect to the model with fixed capacity (compare Table 2). This holds in all scenarios studied as detailed in Appendix C. Investment is thus the first remedy to the ETS induced electricity cost. Notwithstanding these consumption increases, the allowance prices are lower than in the corresponding fixed capacity cases as a result of the higher proportion of (new) CO_2 free

[10]We computed this value on the basis of information provided by the European Commission for the period 2008-2012. See $http://europa.eu/rapid/pressReleasesAction.do?reference=IP/07/1869\&format=HTML$.

TWh	N-EIIs	EIIs	Total
II_NETS_IR	665	706	**1,371**
II_ETS_IR	654	590	**1,244**
II_ETS_SAC	650	575	**1,225**
II_ETS_ZAC	654	611	**1,265**

Table 4: Annual Electricity Demand under Different Investment Scenarios

capacity. Allowance prices are 19.21 €/ ton, 24.80 €/ton and 19.26 €/ton respectively in the marginal cost price, regional price and zonal price (II_ETS_R, II_ETS_SAC and II_ETS_ZAC) models against 24.44 €/ton, 28.48 €/ton and 28.21 €/ton in the corresponding scenarios when when capacity was fixed (IFC_ETS_R, IFC_ETS_SAC and IFC_ETS_ZAC respectively). We elaborate on these results.

6.1 Reference Case with (II_ETS_R) and without (II_NETS_R) ETS

Notwithstanding investments in clean technologies, the ETS still imposes significant electricity costs on EIIs as we now explain. Generators build a total of 43,788 MW of new capacities without CO_2 constraint (NETS_R) and only 29,242 MW with the ETS (ETS_R). Table 4 shows the consumption counterpart of this investment decrease: EIIs lessen their power consumption from 706 TWh (NETS_R) to 590 TWh (ETS_R). This cut is proportionally higher than under the fixed capacity approach where it was of 11%. Similarly N-EIIs consumption drops 665 TWh to 654 TWh (again proportionally more than the 0.5% with fixed capacity). The price effects leading to these drop are described in Appendix B.2.

The ETS also induces generators to change their technology mix towards clean technologies. The switch concerns the utilization of existing capacities but mainly applies to the choice of new ones. Generators reduce the utilization of existing lignite/coal power plants in favour of CCGT and clean technologies in the ETS scenario. They also replace the investments in lignite and coal with new renewable based plants. Investments in nuclear remain high, but as mentioned above are limited to France. The detail of these investments in presented in Appendix D.

6.2 Regional (II_ETS_SAC) and Zonal (II_ETS_ZAC) Price

Roughly speaking, generators maintain the ETS driven investment pattern under average cost prices. The question is whether these contracts change electricity costs in a way that mitigates the impact of the ETS on demand and investments. The electricity consumption reported in Table 4 helps understanding the following investment figures. Total investment amounts to 26,195 MW with regional price (ETS_SAC), a reduction compared to the 29,242 MW investment under marginal cost pricing (ETS_R). The regional price therefore appears counter-productive. In contrast, investment amounts to 31,992 MW with the zonal price (ETS_ZAC) and hence does better than under marginal cost prices. Zonal pricing is thus still an effective remedy to the ETS induced electricity cost. We now delve into these differences.

6.2.1 Capacity allocation does not explain these different impacts

The allocation of new capacities to EIIs and N-EIIs differs in the zonal and single average cost pricing policies but this is compensated by the allocation of existing capacities (see Appendix

E for some elaborations). The total renewable and nuclear capacities allocated to EIIs are almost identical, whether in the regional or zonal price regimes[11]. The proportion of the other technologies dedicated to EIIs is also similar in both average cost price regimes [12]. The totals are different though: the capacity dedicated to EIIs amounts to 65,642 MW and 69,758 MW respectively in the regional (ETS_SAC) and zonal (ETS_ZAC) price regimes. This is compatible with the consumers' demand reported in Table 4.

6.2.2 National energy policies explain the different impacts

As already observed in the fixed capacity analysis, the regional price entails a drop of consumption compared to marginal cost pricing in those zones where nuclear capacity is significant. Investments reinforce these effects. Specifically French EIIs' consumption decreases from 243 TWh with marginal cost pricing to 176 TWh with the regional price. The reason is that the regional price reduces the cost of imports of French nuclear electricity by countries that cannot invest in that technology. In other words, the regional price forces French EIIs to share national nuclear capacity with foreign industries.

The impact is dramatic: total French nuclear generation for EIIs is 30,492 MW with regional price of which 20,091 MW (66% of total production) supplies domestic EIIs and the remaining 10,400 MW is exported. French electricity prices for EIIs become higher than the average of the marginal cost prices of the reference ETS scenario with investments (II_ETS_R), leading to a 28% cut of EIIs electricity consumption. A similar phenomenon appears at the Belgian node Gramme where industries reduce their power demand by almost 10% under a single price policy applying with ETS (from 19 TWh in the ETS_R model to 18 TWh in the ETS_SAC case). Contrarily, the regional price is lower than the former marginal cost in the other nodes, because they benefit from these exports at average generation and transmission cost. To sum up, EIIs' electricity cost decreases and energy demand increase, at all nodes but France and Gramme. Together these positive effects are not sufficient to compensate the high negative demand variations registered in France and in Gramme. The results is a global cut of industrial electricity demand of about 2.6% with respect to the reference ETS levels (ETS_R)[13].

N-EIIs do not do well either in the regional price scenario (ETS_SAC). They globally reduce their power consumption by 1% with respect to the ETS reference case (ETS_R) as seen in Table 4. As explained in Appendix F, this is due to the price of allowances.

The situation is altogether different with zonal price where local generators supply EIIs. They increase their global electricity consumption by 4% and 6% with respect to the reference ETS (ETS_R) and single (ETS_SAC) price scenarios (see Table 4). The drawback is that this impact varies locally. French and all Belgian EIIs benefit from the zonal average cost price and reach a higher level than before the inception of the ETS (NETS_R)[14]. In contrast, the zonal price becomes so expensive in the Dutch locations that EIIs' power demand becomes lower than in the reference ETS level (ETS_R). German EIIs benefit from the zonal price

[11] Nuclear power plants devoted to EIIs in the ETS_SAC amount to 39,423 MW while in the ETS_ZAC are 39,805 MW, which respectively correspond to the 49% and the 42% of the total dedicated capacity. We have similar results also for the renewable capacities: 7,499 MW in the ETS_SAC and 7,275 MW in the ETS_ZAC.

[12] In order the capacities dedicated to EIIs are: nuclear, lignite, renewable, coal, CCGT and hydro.

[13] The drop computed with respect to the NETS_R amounts to 19%.

[14] EIIs' demands in France and in the Belgian locations Merchtem and Gramme are 243 TWh, 43 TWh and 21 TWh in the NETS_R scenario, while they amount to 254 TWh, 44 TWh and 23 TWh in the ETS_ZAC case.

system.

6.3 Welfare Analysis

The welfare analysis presented in Table 5 give an alternative view of these phenomena. Investments increase social benefit as seen from Tables 5 and 3. This holds for all cases. The 171.58 Billion €welfare entailed by the zonal price regime (ETS_ZAC) is almost identical to that of the reference ETS case (ETS_R) which amounts to 171.72 Billion €. This value is also the one achieved with the same reference investment case but with fixed capacities (IFC_ETS_R). All this suggests that the zonal price system with investments effectively and efficiently mitigates the electricity cost induced by the ETS. Note that the N-EIIs' surplus with zonal price (ETS_ZAC) is almost identical to that in the reference ETS system (ETS_R)

Billion €	**II_NETS_R**	**II_ETS_R**	**II_ETS_SAC**	**II_ETS_ZAC**
EIIs	20.18	14.68	12.47	15.08
N-EIIs	136.97	132.55	130.89	132.56
Consumers	**157.15**	**147.23**	**143.36**	**147.65**
Generators	**15.79**	**23.51**	**26.09**	**22.95**
Allowances		*6.90*	*8.90*	*6.91*
TSO	**0.52**	**0.99**	**1.21**	**0.98**
Welfare	**173.46**	**171.72**	**170.66**	**171.58**

Table 5: Welfare under Different Investment Scenarios

The analysis of the EIIs' and N-EIIs' surplus reflect demand evolutions. The zonal price increases EIIs' surplus (ETS_ZAC) compared to the reference ETS marginal cost scenario (ETS_R). Not shown on the table, EIIs' surplus increases in France and in Belgium overcome surplus reductions in the remaining locations.

The situation is different under the single price system (ETS_SAC), but are again in line with the observation of the demand. Industries globally reduce both electricity demand and surplus with respect to the reference ETS case (ETS_R) levels. The decrease occurs in France and the Belgian Gramme node and is not compensated by the increases a the other locations.

In contrast, generators gain in all ETS scenarios. Line "Generators" of Table 5 reports their profits computed by assuming that all allowances needed are fully grandfathered. Profits increase with respect to the non ETS reference case (NETS_R) by 49%, 65% and 45% respectively in the ETS reference case (ETS_R), single price case (ETS_SAC) and zonal price case (ETS_ZAC). The line "Allowances" reports the global allowances costs computed as the product of the allowance prices in the different scenarios and the emission cap. The generators' profits under the hypothesis of full auctioning are simply obtained by subtracting these allowance values from the corresponding profit reported at line "Generators". Note that generators' profits are higher than before the inception of ETS (NETS_R) even with full auctioning. This phenomenon is explained by the general augment of the electricity prices (at least those paid by N-EIIs) caused by the ETS.

Again, the social welfare includes the TSO' merchandising profits accruing from the introduction of a flow based market coupling organization in transmission.

7 Modelling the Combination of the ETS Induced Carbon and the Electricity Costs (DII)

We now account for the EIIs' *direct* carbon costs and participation to the emission market. This is done in two steps. We first expand the cap on allowances to include EIIs' emissions. Because of lack of information on the separate reactions of the EIIs to electricity and allowances prices, we then embed both effects in the EIIs' electricity demand function. This is done by adding a carbon component to the price of electricity: the approach is described in Appendix G.

We analyze two different investment scenarios: one without free allowance to industries (hereafter "EIINA") and one with free allowances (hereafter "EIIA"). The current legislative proposal for the period after 2012 does not clearly state what the policy towards EIIs will be. Article 10b of the proposed revision of Directive 2003/87/EC states that *Not later than June 2011, the Commission shall, in the light of the outcome of the international negotiations and the extent to which these lead to global greenhouse gas emission reductions, ..., submit to the European Parliament and to the Council an analytical report assessing the situation with regard to energy-intensive sectors or sub-sectors that have been determined to be exposed to significant risks of carbon leakage. This shall be accompanied by any appropriate proposals, which may include: (1) adjusting the proportion of allowances received free of charge by those sectors or sub-sectors under Article 10a (compare Section 1); (2) inclusion in the Community scheme of importers of products produced by the sectors or sub-sectors determined in accordance with Article 10a. Any binding sectoral agreements which lead to global emissions reductions of the magnitude required to effectively address climate change, and which are monitorable, verifiable and subject to mandatory enforcement arrangements shall also be taken into account when considering what measures are appropriate.*

We assume that the EU acts with the double objective of protecting its industry and maintaining the overall emission reduction objective. Supposing (for technical reasons) that EIIs production and electricity consumption are proportional, we further introduce the major policy assumption that free allowances will be allocated proportionally to EIIs' production (benchmarking policy) and hence to their electricity consumption. This policy fits the objective of protecting EIIs in the international competition. Alternatively, one can also consider the assumption simply as a first step of the analysis. We calibrate the demand for allowances and the industrial emission factors on the year 2005 (available at CITL [1]). The data used in the models of this section are the same as before, except for the introduction of these emission factors and the total emission cap, which is increased to 710 Mio ton p.a in order to account for EIIs emissions. We concentrate on the joint impact of the special pricing contracts and the free allowances.

We implemented both the fixed capacity and investment models but, for the sake of brevity, only report results with investments. As before, we drop the "DII" model identifier for results obtained under the assumptions of this section.

Table 6 reports the annual EIIs, N-EIIs' and total electricity demand in the different scenarios. The columns "II" recall results obtained in Section 6 with the sole electricity cost. The other columns lists new results obtained by modelling both carbon and electricity costs under the alternative assumptions that EIIs do not receive ("EIINA") and receive free allowances ("EIIA").

The comparison of the second and following two columns of Table 6 quantify the impact of the carbon cost on EIIs. This points to a very obvious message: adding carbon costs

	IMPACTS on EIIs			IMPACTS on N-EIIs			TOTAL DEMAND		
TWh	**II**	**DII**		**II**	**DII**		**II**	**DII**	
		EIINA	**EIIA**		**EIINA**	**EIIA**		**EIINA**	**EIIA**
NETS_R	706			665			1,371		
ETS_R	590	517	574	654	657	652	1,244	1,174	1,226
ETS_SAC	575	492	580	650	656	650	1,225	1,148	1,230
ETS_ZAC	611	**Infeasible**	585	654	**Infeasible**	651	1,265	**Infeasible**	1,236

Table 6: EIIs and N-EIIs' Annual Electricity Demand under Different Market Organizations

to electricity costs further reduces EIIs' activities. The overall decrease can be decomposed in two parts. The move from 706 TWh (II_NETS_R) to 590 TWh (II_ETS_R) observed in the second column is the impact of the electricity cost without special contracts and carbon cost (see Section 6 for more details). Carbon cost without free allowances further lowers consumption from 590 TWh (II_ETS_R) to 517 TWh (ETS_R_EIINA). Free allowances granted in amounts similar to the second phase of the ETS drastically reduce this second impact which is now limited to a decrease of demand from 590 TWh (II_ETS_R) to 574 TWh (ETS_R_EIIA).

We saw that N-EIIs reduce their electricity demand under the ETS because of higher prices. The burden put on EIIs when there is no free allocation helps N-EIIs recover from that situation: the significant demand drop of EIIs' demand in the reference ETS scenario (ETS_R) frees generation capacity and reduces the marginal cost of electricity to N-EIIs. Free allowances eliminate this recovery of N-EIIs. The results confirm that free allowances mitigate the impact of carbon cost on EIIs. They also reveal an impact on N-EIIs.

It remains to examine whether special contracts still mitigate the impact of the electricity cost on EIIs. The outcome is mixed and, as shown in Table 6, can even be extreme. A combination of zonal pricing and full auctioning (ETS_ZAC_EIINA) makes the model infeasible, implying that it is impossible to meet the environmental target without free allowances for EIIs[15]. The special price contracts are only productive under free allowances; zonal prices then do better than regional prices. We elaborate on these findings.

7.1 Reference Case with (DII_ETS_R) and without (DII_NETS_R) ETS: Full Auctioning (EIINA) and Free Allowances (EIIA)

The addition of the carbon cost to electricity cost without a compensation through free allowances further reduces EIIs' demand from 590 TWh (II_ETS_R) to 517 TWh (ETS_R_EIINA). All zones contribute to the decrease. Investments reduce from 29,242 MW in the reference ETS case with the sole electricity costs (II_ETS_R), to 14,921 MW with both carbon and electricity costs (ETS_R_EIINA), no allowance and no special price contract (compare Tables 10 and 11 in Appendix H). The price of allowances is also low and equal to 12.45 €/ton, which encourages the use of existing coal capacity. Free allowances significantly mitigate the impact of carbon cost on EIIs. Industrial demand only decreases from 590 TWh (II_ETS_R) to 574 TWh (ETS_R_EIIA). In this last case, investments amount to a total of 30,338 MW because of a combined effect of demand increase and capacity restructuring (see Table 12 in Appendix H). The allowance price increases to 22.26 €/ton and induces investing in clean

[15]Feasibility is reached by relaxing the emission constraints and indirectly the amount of allowances they have to pay for.

technologies and scrapping existing coal capacities. This also increases N-EIIs' prices and decreases their consumption compared to the other reference cases in Table 6[16]. Notwithstanding this improvement EIIs do not recover the position observed with the sole electricity costs.

To sum up the granting of free allowances in proportion to production, that is according to a benchmark policy effectively compensates for carbon costs.

7.2 Regional Price (DII_ETS_SAC): Full Auctioning (EIINA) and Free Allowances (EIIA)

7.2.1 Full auctioning (EIINA)

A regional price (ETS_SAC) with full auctioning of allowances does not help EIIs. We argued in Section 6.2 devoted to the sole electricity cost that the regional price reduces consumption from 590 TWh (II_ETS_R) to 574 TWh (II_ETS_SAC) and that the diversity of national energy policies explains this counter-productive effect. The application of a regional price to a market with both carbon and electricity costs and no free allowances similarly decreases EIIs' demand from 517 TWh (ETS_R) to 492 TWh (ETS_SAC). In short, EIIs suffer not only from both carbon and electricity costs but also from the counter-productive effect of the intended (regional price) remedy. The explanation is similar to the one of Section 6.2: a regional price applied on diverging energy policies subsidizes exports of nuclear energy by reducing the transmission costs of that export. This deprives French EIIs from the benefits of domestic nuclear developments. French EIIs consumption drops from 211 TWh in the pure marginal cost pricing (ETS_R) to 152 TWh (ETS_SAC) with the regional price. Belgian EIIs' consumption similarly drops in Gramme from 17 TWh to 15 TWh between these two scenarios. As in Section 6.2, the regional price (ETS_SAC) benefit EIIs in the remaining locations, with respect to the corresponding reference case. Altogether the rises do not compensate French and Belgian losses.

A by-product is that N-EIIs benefit from the regional price. Decreasing consumption lowers the allowance price to 14.71 €/ton (ETS_SAC) and hence also the marginal cost of electricity to N-EIIs. These increase their consumption with respect to the levels computed with the regional price when only accounting for electricity cost (II_ETS_SAC)[17].

Finally, the reduced EIIs' demand of electricity and low allowance price affect investments. These reduce to 8,927 MW with a regional price without free allowances (ETS_SAC_EIINA) MW (see Table 11), -66% less than with the sole electricity costs (II_ETS_SAC).

7.2.2 Free allowances (EIIA)

Free allowances improve the picture: EIIs electricity demand increases from 574 TWh with marginal cost pricing (ETS_R_EIIA) to 580 TWh with regional price (ETS_SAC_EIIA). This looks like a marginal variation, but it is significant when compared to the application of the regional price with full auctioning where EIIs demand was 492 TWh Again, French EIIs have

[16] Like in the other reference investment cases in Table 6, coal and CCGT plants define the N-EIIs' summer and winter electricity prices in the DII_ETS_R_EIIA model. N-EIIs' demand falls is summer are 0.3% and 1% with regard to the II_ETS_R and the DII_ETS_R_EIINA cases, while in winter are respectively of 0.3% and 0.7%.

[17] Note that both in the II_ETS_SAC and the DII_ETS_SAC_EIINA models, coal and CCGT plants define N-EIIs' electricity prices in summer and in winter respectively. Considering the marginal cost pricing approach, a lower allowance price reduce also electricity price if fuel charges do not change.

to give up some of the benefit of domestic nuclear capacities because of a pricing system that subsidizes exports. The same happens in the Belgian node Gramme. This implies that the decrease of French consumption is drastic, even though smaller in Gramme. These decreases are barely compensated by the increases in other countries[18] but the net result is this time positive.

N-EIIs, which do not incur direct carbon costs, roughly maintain their consumption with respect to the regional price scenario computed with the sole electricity cost (II_ETS_SAC) (see Tables 6). The key element here is the is allowance price, which at 24.80 €/ton remains the same in both scenarios and adds to coal and CCGT fuel costs to set the electricity price for N-EIIs.

Finally, investments in new capacity totally amount to 29,544 MW, a much higher value than with full auctioning (compare Tables 11 and 12 in Appendix H). This again results from a joint demand increase and technology restructuring effect due to the high allowance price.

7.3 Zonal price (DII_ETS_ZAC): Full Auctioning (EIINA) and Free Allowances (EIIA)

The combination of zonal prices, carbon cost and full auctioning makes the model infeasible: the market cannot meet the reduction target. Free allowances restore the situation. EIIs increase their activity with respect to various other situations as can be seen from the results of Table 6. The increase of demand from 574 TWh with marginal cost pricing and free allowances (ETS_R_EIIA) to 585 TWh with zonal prices and free allowances (ETS_ZAC_EIIA) indicates that this policy mix partially remedies the demand lost because of the electricity cost. But this recovery is small: one can measure the loss incurred by EIIs as a result of the ETS after compensation with free allowances by the drop of demand from 706 TWh (II_NETS_R) to 574 TWh (ETS_R_EIIA). A recovery of 11 TWh is only 8% of that amount. The reason again lies in the diversity of energy policies, which this time operates as follows: French and all Belgian industries increase their electricity demand compared to the reference case ETS_R_EIIA because of their access to the nuclear and new renewable capacities; but EIIs' consumption in the other nodes falls because they miss this access.

This larger electricity demand increases the allowance price. It amounts to 24.76 €/ton against the 22.26 €/ton in the corresponding reference case with free allowances (ETS_R_EIIA). The combination of these demand and allowance price effects in turn increases investment which now amount to 32,957 MW

As before, the higher allowance price slightly increases N-EIIs' electricity prices compared to the reference marginal cost case (ETS_R)[19]: N-EIIs' consumption falls by -0.2% (see Tables 6).

7.4 Welfare Analysis

Tables 7 and 8 report the surpluses/profits of the market players when allowances are respectively fully auctioned and are given for free. We report the EIIs' gross and the net surpluses, that are before and after accounting for allowance payments respectively. The allowance values are indicated in line "Allowances (EIIs)". Note that by construction, in the EIINA model,

[18] In absolute values, the fall of the French industrial demand is from 240 TWh in the ETS_R_EIIA to 174 TWh in the ETS_SAC_EIIA. In Gramme, the EIIs' demand drop is from 20 TWh to 19 TWh.

[19] Again, coal and CCGT defines their periodical prices both in the DII_ETS_R_EIIA and in the DII_ETS_ZAC_EIIA. The difference between the two models is still represented by allowance price.

these values are subtracted from the EIIs' gross surplus, while in EIIA models they adds to the gross surplus. In both cases, they result in the net surplus. A similar presentation applies to generators. "Gross generators" and "Net generators" show profits respectively with and without full allowance grandfathering. Costs of allowances are reported in line "Allowances".

		EIINA	
Billion €	**II_NETS_R**	**DII_ETS_R**	**DII _ETS_SAC**
Net EIIs	20.18	15.58	13.85
Allowances (EIIs)		*4.18*	*4.71*
Gross EIIs		11.40	9.14
N-EIIs	136.97	133.88	133.20
Consumers	**157.15**	**149.46**	**147.05**
Gross Generators	15.79	21.23	22.87
Allowances		*4.47*	*5.30*
Net Generators		16.76	17.57
TSO	**0.52**	**0.84**	**0.92**
Welfare	**173.46**	**171.53**	**170.84**

Table 7: Welfare Analysis of the DII_EIINA Models

EIIs' surplus parallel consumption tendencies in the different full auctioning (EIINA) scenarios. The same is true for N-EIIs' surplus. The ETS increases generators profits (move from II_NETS_R to ETS_R_EIINA or ETS_SAC_EIINA) and this notwithstanding the absence of free allowances. Note that these profits do not contain any element of market power: they simply result from the competitive mechanism of marginally passing allowance costs into electricity prices

		EIIA		
Billion €	**II_NETS_R**	**DII_ETS_R**	**DII_ETS_SAC**	**DII_ETS_ZAC**
Gross EIIs	20.18	13.97	12.54	14.00
Allowances (EIIs)		*0.05*	*0.17*	*0.02*
Net EIIs		14.03	12.71	14.02
N-EIIs	136.97	131.78	130.84	131.43
Consumers	**157.15**	**145.76**	**143.38**	**145.45**
Generators	15.79	24.43	25.24	**24.43**
Allowances		*7.99*	*8.90*	*8.89*
Net Generators		16.44	16.34	15.54
TSO	**0.52**	**1.08**	**1.22**	**1.10**
Welfare	**173.46**	**171.26**	**169.84**	**170.97**

Table 8: Welfare Analysis of the DII_EIIA Models

In the EIIA, the profit pattern of generators is more diverse than in Table 7. Profits increase compared to pre ETS situation (II_NETS_R) in both the marginal (ETS_R_EIIA) and regional price scenarios (ETS_SAC_EIIA). But it slightly decreases in the zonal price scenario (ETS_ZAC_EIIA).

8 Conclusion

We analyse policies consisting of a mix of free allowances and special electricity contracts for EIIs. We find that special full cost based pricing contracts help relieve the electricity costs imposed by the ETS on EIIs. But the benefits of these contracts are hampered by differences of national energy policies. The regional price helps EIIs located in non nuclear countries and the opposite is true for the zonal contracts. All in all, zonal prices seem to do better. This is to some extent not surprising because the regional price system embeds a subsidizing effect that can only be detrimental to efficiency. Zonal prices may not look like an internal market solution but the regional price, with its subsidizing effects, is a false internal market solution. The differences as to who gains and who looses in the different policies and the willingness to maintain national policies suggest that it will be difficult to arrive at an harmonized solution in the EU.

The situation is clearer for free allowances. As expected they always help EIIs recover their carbon costs, at least when applied as here on a benchmarking basis. The difficulty is thus to get the benchmarking principle accepted at the EU level.

N-EIIs are generally loosing in the adventure. They remain priced at marginal cost and hence suffer from higher allowances cost than EIIs which pay them at average cost. Moreover, the higher the success of the EIIs policy is, the higher the allowance price and hence the electricity price to N-EIIs.

This analysis does not take any position on the importance of carbon leakage. It simply points to problems that could arise were this phenomenon important. It is indeed particularly worrying to note that it is extremely difficult to find quantitative information about the reality of the phenomenon and the reaction of the EIIs to electricity an carbon costs. A main conclusion of the analysis is thus to draw the attention to the fact that we need to understand these reactions much better than is the case today. A last comment is the crucial importance of nuclear policy. Renewable and nuclear are key players in the policies investigated here. But we probably cannot afford to only rely on subsidized renewable.

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Appendix A: Underlying Mathematical Techniques and their Implementations

Our models are formulated as complementarity problems. More specifically, given a cone K and a mapping $F : K \to R^n$, the complementarity problem, denoted by $CP(K, F)$ is to find a nonnegative vector $x \in R^n$ satisfying the following condition:

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

where $F(x)$ is assumed to be nonnegative. The use of the term "complementarity" derives from the concept of orthogonality ($\perp$) stated in the definition. In fact, the scalar product $F(x) \cdot x$ equals zero.

Complementarity based models offer a natural approach to construct partial and general equilibrium problems where several market agents interact together. In our specific case, we consider the generators, the consumers and the TSO. Their complementarity models are obtained by computing the KKT conditions of their optimization models and matching them with the associated primal and dual variables.

Generators solve two different pricing models in accordance with the electricity pricing scenario considered. In the reference case, representing a perfectly competitive market, generators are (energy and transmission) price takers and maximize their profits accruing from selling electricity to both consumer segments. In doing that, they have to account for the capacity constraint of their power plants.

In the leakage mitigation scenarios, generators maximize their profit when selling to N-EIIs and minimize the cost of supplying EIIs. This different optimization approach is a direct consequence of the application of average cost prices which do not lead to maximize profits. However, generators are charged in the same way for transmission on both segments.

This has also some mathematical implications. While our perfectly competitive optimization model defines a convex problem and has a global solution, the average cost pricing scenarios introduce non- convexity[20] that may lead to either a multiplicity of disjoint equilibria or no equilibrium. Apart from a very difficult case in the third stage of our analysis, our average cost pricing models have several disjoint solutions[21].

In any pricing scenarios, EIIs and N-EIIs maximize their surpluses. In addition, our models account for the energy market balance, the transmission and the emission constraints.

The final complementarity problems are obtained by assembling together the KKT conditions of the market agents' optimization problems and the market clearing relations. This set of complementarity problems are solved in GAMS by PATH as explained by Dirkse and Ferris [5].

Appendix B: Pricing Effects in the Reference Cases with and without ETS

Appendix B.1. With Fixed Capacities

The introduction of the carbon market has a dual effect on the seasonal marginal prices of electricity. Summer prices increase in IFC_ETS_R compared to IFC_NETS_R. We observe that the same coal plant set the price of electricity at the hub both in the IFC_NETS_R and IFC_ETS_R models. But in IFC_ETS_R, generators pass the allowance (opportunity) costs in the electricity prices which thus increases the price paid by EIIs and N-EIIs. The result is opposite in winter where prices decrease under the ETS. The cause is the EIIs' demand decrease which eliminates the most emitting plants from the merit order: generators use both old single cycle natural gas and oil-fired power plants in the IFC_NETS_R scenario, which entail a high electricity price. These highly emitting plants are abandoned in the ETS where CCGT power stations become marginal. This decreases the price of electricity. The combination of a lower price and a lower demand may look counter-intuitive, but it is explained by the imposed equality of EIIs power demand in both the summer and winter. It is not the lower winter price that induces the lower EIIs' demand, but the combination of a

[20] Non-convexity corresponds to non-monotonicity in the complementarity problems.

[21] We obtained different results by setting different starting points for the algorithm.

higher summer price and a lower winter price that implies a lower demand in both summer and winter. The ETS introduces some changes in technology mix used to produce electricity with a consequent modification of the electricity prices. In particular, in the ETS_R scenarios with carbon restrictions, this interpretation is confirmed by the more intuitive behaviour of N-EIIs. There is no inter–seasonal link of consumption for these consumers. They accordingly increase their consumption by 1% in the winter period in the IFC_ETS_R scenario where prices are a little bit lower in each node than in the IFC_NETS_R scenario. In summer, instead, they reduce their energy utilization by almost 3% as a consequence of the higher power prices. The decrease of the summer N-EIIs' demand prevails on the corresponding winter increase and this results in a global N-EIIs' demand reduction as indicated in Table 2. The phenomenon globally illustrates that generators' capability to transfer their carbon costs in the final price paid by consumers is limited in the long-term if the reaction of the EIIs is important.

Appendix B.2. With Investments

Increases of electricity prices cause these global demand fall: coal and CCGT power plants set the marginal electricity prices respectively in summer and in winter both with and without the ETS. The marginal cost prices then increase because of the additional carbon cost implied by the ETS.

Appendix C: Impact of Investments on Electricity Demand of the Reference Case with and without ETS

The comparison of the data reported in Tables 2 and 4 shows that, in the absence of the ETS and with investments (II_NETS_R) EIIs increase their demand by 18% compared to the case with fixed capacities (IFC_NETS_R), that is, an increase from 598 TWh to 706 TWh. N-EIIs' increase is about +2% (from 649 TWh to 665 TWh). This positive tendency is also confirmed by the couple II_ETS_R and IFC _ETS_R: with investments and ETS, EIIs augment their electricity consumption by 11% (from 531 TWh to 590 TWh) compared to the application of the ETS with fixed capacities. N-EIIs raise their energy demand by 1% (from 646 TWh to 654 TWh).

Appendix D: Discussion of Investments Patterns in the "II" scenarios

Among the 43,788 MW of new capacities invested without ETS (II_NETS_R), 17,799 MW (41%) are nuclear in France, 18,570 MW (42%) lignite in Germany and 7,419 MW (17%) coal distributed between Belgium and the Netherlands. With the 29,242 MW of new capacity invested with ETS (II_ETS_R), 26,641 MW (91%) are new nuclear plants in France and the remaining 2,600 MW (9%) are renewable in Belgium. Generators choose these locations for different reasons. As already said, France is the unique country in the model that allows investments in nuclear; new renewable stations happen to be, in our input data, less expensive to build in Belgium than in the other countries. Moreover, because of their high capacity costs and limited availability, there are no investments in hydro plants.

Appendix E: Capacity allocation in the II_ETS_SAC and in the II_ETS_ZAC Models

Generators reserve 29,533 MW of the 31,992 MW invested under the zonal pricing policy (II_ETS_ZAC) to N-EIIs of which 1,620 MW are renewable plants in Belgium and 27,913 MW are nuclear power stations in France. Investments for EIIs are only 2,458 MW of new renewable plants built in Belgium. In contrast, in the single price regime (II_ETS_SAC), 17,400 MW of investment go to EIIs and 8,796 are for N-EIIs. Again, these are nuclear (in France) and renewable (in Germany and in Belgium) power stations that, this time, are reserved both to EIIs and N-EIIs.

This allocation of new capacities implies that EIIs are mainly supplied by existing plants and one indeed observes that the allocation of the existing renewable and nuclear capacities follows an opposite pattern in the two average cost pricing models.

In both the regional and zonal models, old gas and oil existing plants are reserved for N-EIIs but are never used even in winter. These plants should thus be scrapped. We also observe that in both average cost pricing scenarios, part of the N-EIIs' old or new French nuclear capacities remains idle in summer because total capacity exceeds demand and network congestion does not allow more export of nuclear energy.

Appendix F: Allowance Prices in the "II" Scenarios

The increase of the allowance price from 19.21 €/ton in the reference ETS case to 24.80 €/ton under single price (respectively II_ETS_R and II_ETS_SAC) explains the N-EIIs' consumption decrease: the higher allowance price affects the same coal and CCGT plants that set N-EIIs' marginal prices in summer and in winter in both scenarios and hence increases electricity prices. The smaller investment in clean technologies, caused by the drop of investment, and hence the increased utilization of fossil plants in turn explain the raise of allowance price.

As argued before, new investments are mainly dedicated to N-EIIs in the zonal pricing system while EIIs are supplied by existing capacities. The two nodes with investments are thus largely exporting to N-EIIs. This especially holds for France where old and new nuclear provides 77% of the electricity generated at the node and covers the 92% of the power exported. This benefit N-EIIs that recover their ETS reference level of 654 TWh, notwithstanding the global increased consumption of the EIIs.

Appendix G: Modelling the Direct ETS Impact

The following requires introducing an assumption of proportionality between emissions and electricity consumption (linear technology). It expresses that EIIs' emissions depend on production levels that, in turn, determine electricity consumption. Because of the lack information, we consider the whole EIIs sector as one firm. This restriction is not methodological and it can be relieved with sectoral data. Let π denote the profit function of this aggregate firm. We want to study its reaction to changes of both the electricity and allowance prices and include both effects in the sole demand function. The profit π is stated as:

$$\pi = p_y \cdot y - p_e \cdot e - p_o \cdot o - p_{co_2} \cdot co_2 \tag{2}$$

which is interpreted as follows. Industries' revenues accrue from selling output y at price p_y. They consume non electricity inputs o and electricity e to produce output y. Let p_o and p_e be the prices of these inputs. Industries incur a cost p_{co_2} for each allowance bought on the market; co_2 is the net purchase, that is the amount of emissions reduced by the allowances received for free.

Introducing the policy assumption that free allowances are granted proportionally to production and the technological assumption that the amount of electricity e, allowances co_2 and input o vary as a function of production we can write:

- $e = \alpha \cdot y$
- $co_2 = (\beta - \gamma) \cdot y$
- $o = \varphi(y)$

where α represents the unit electricity consumption (a technical parameter), β is the emission factor per unit of output y (a technical parameter) and γ is the proportion of free allowances received by unit y (a policy parameter). $\varphi(y)$ is the consumption of non electricity input as a function of the output y. Recall that we stated a linear dependence between the demand of energy e and allowances co_2 and the industrial production y (again this is not a methodological limitation) but for reason that will be clear later in the section, we allow for a slightly more general treatment of the consumption of non electricity input $\varphi(y)$

We can then write (2) as a function of the sole output y and obtain:

$$\pi(y) = p_y \cdot y - p_e \cdot \alpha \cdot y - p_{co_2} \cdot (\beta - \gamma) \cdot y - p_o \cdot \varphi(y) \tag{3}$$

We arrive at the industrial demand of electricity by computing the First Order Conditions (FOC) of (3) with respect to y and obtain:

$$\frac{\partial \pi}{\partial y} = p_y - p_e \cdot \alpha - p_{co_2} \cdot (\beta - \gamma) - p_o \cdot \varphi'(y) = 0 \tag{4}$$

Our objective is to separately get hold of the electricity price (p_e), which measures the indirect ETS costs and of the allowance price (p_{co_2}) which determines the direct carbon cost. We then re-write condition (4) as follows:

$$p_e \cdot \alpha + p_{co_2} \cdot (\beta - \gamma) = p_y - p_o \cdot \varphi^{'}(y) \tag{5}$$

By dividing by α on the left and right hand sides of equation (5), one gets:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = \frac{1}{\alpha} \left[p_y - p_o \cdot \varphi'(y)\right] \tag{6}$$

which has the form of a demand function: the left hand side is a combination of the electricity and allowance prices which has the dimension of a euro/MWh while the right hand side is only a function of the output of the firm (the price of the output is fixed in this partial equilibrium model). Because we are assuming linear demand functions throughtout, we now impose the particular functional form $\varphi^{'}(y) = a + b \cdot y$ and write:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = \frac{1}{\alpha} \left[p_y - p_o \cdot (a + b \cdot y)\right] \tag{7}$$

Using the relation $e = \alpha \cdot y$, we substitute y in (7) and obtain:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = p_y \frac{1}{\alpha} - p_o \frac{a}{\alpha} - p_o \frac{b}{\alpha^2} e \tag{8}$$

By setting $A = p_y \frac{1}{\alpha} - p_o \frac{a}{\alpha}$ and $B = p_o \frac{b}{\alpha^2}$, we have:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = A - Be \tag{9}$$

This is the intended demand function. Equation (9) represents the industrial demand of electricity, where p_e and e are respectively the EIIs' electricity price and demand. It includes also the emission allowance price p_{co_2} multiplied by the factor $(\frac{\beta-\gamma}{\alpha})$ which defines the impact of the application of different emission policies on EIIs. This demand function allows one to consider different scenarios of free allowances to the EIIs such as:

1. full grandfathering of allowances ($\beta = \gamma$). This is in line with the situation prevailing in the 2005-2007 ETS phase;

2. Full auctioning of allowances ($\gamma = 0$). This is what is foreseen for the period after 2012 by the proposed revision of the ETS Directive;

3. Partial grandfathering of allowances ($\beta \neq \gamma$). This is a more general situation which can represent a declining free allowance policy for EIIs or a full free allocation as foreseen by the proposed new ETS Directive in case industries become too exposed to international competition.

As mentioned before, we limit the analysis to two contrasted scenarios. We first consider the case of full auctioning which is modelled by setting the value of γ to zero. The factor $(\frac{\beta-\gamma}{\alpha})$ becomes $(\frac{\beta}{\alpha})$, which is an emission factor that we compute on the basis of 2005 data available at CITL [1]. We refer to this case as "EIINA". We also consider the scenario "EIIA" where industries receive a proportion of free allowances. In this scenario, we have the factor $(\frac{\beta-\gamma}{\alpha})$ to which we refer as "allowance factor". Both approaches are compatible with the proposed revision of the ETS Directive. The emission component of the electricity price is $p_{co_2} \cdot \frac{\beta}{\alpha}$ in the EIINA models and $p_{co_2} \cdot \frac{\beta-\gamma}{\alpha}$ in the EIIA scenarios. The EIIs' demand for allowances is:

$$allowance \quad demand = \frac{\beta - \gamma}{\alpha} \cdot e$$

The inclusion of the emission/allowance in the industrial electricity demand modifies EIIs' electricity consumption that now depends on both the power and carbon prices.

Appendix H: Investments and Capacity Allocations

Table 13 report the EIIs' demands when nuclear investments are unconstrained. EIIs' demand is identical in the II_NETS_R and in the II_ETS_R scenarios. The reason is that emission constraint is not binding and hence the EIIs' demand is set by nuclear marginal cost in both cases. The situation changes when carbon cost is included in the model. Emission constraint becomes active at low allowance price. Still EIIs must pay for them, which change their demand. This effect disappears with free allowances (see Table 13).

Available Capacity								
MW	**Germany**	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**	**Total**
Hydro	1,505	6,084	0	13	0	0	0	**7,602**
Renewable	4,584	0.95	20	21	101	101	101	**4,930**
Nuclear	15,007	45,369	2,078	2,204	337	0	0	**64,995**
Lignite	17,783	77	0	0	0	0	0	**17,860**
Coal	24,613	8,824	1,564	979	3,128	0	482	**39,590**
CCGT	13,544	8,164	2,589	1,207	4,432	2,917	4,834	**37,687**
Old gas	2,147	256	194	170	833			**3,600**
Oil based		4,760	55	194				5,009
Total	**79,183**	**73,535**	**6,500**	**4,788**	**8,831**	**3,018**	**5,417**	**181,273**

Table 9: Available Capacity by Node in MW

MW	**CAPACITY**		
	Existing	**Investments**	**Total**
II_NETS_R	181,273	43,787	**225,060**
II_ETS_R	181,273	29,242	**210,515**
II_ETS_SAC	181,273	26,195	**207,468**
II_ETS_ZAC	181,273	31,991	**213,264**

Table 10: Total Capacity in the II Scenarios

MW	**CAPACITY**		
	Existing	**Investments**	**Total**
DII_ETS_R_EIINA	181,273	14,921	**196,194**
DII_ETS_SAC_EIINA	181,273	8,927	**190,200**
DII_ETS_ZAC_EIINA	Infeasible	Infeasible	**Infeasible**

Table 11: Total Capacity in the DII Scenarios with Full Auctioning EIINA

MW	**CAPACITY**		
	Existing	**Investments**	**Total**
DII_ETS_R_EIIA	181,273	30,338	**211,611**
DII_ETS_SAC_EIIA	181,273	29,544	**210,817**
DII_ETS_ZAC_EIIA	181,273	32,957	**214,230**

Table 12: Total Capacity in the DII Scenarios with Free Allocation EIIA

TWh	**II**	**DII**	
		EIINA	**EIIA**
NETS_R	789		
ETS_R	789	777	791
ETS_SAC	777	764	779
ETS_NAC	781	768	783

Table 13: EIIs' Electricity Demand Under Different Nuclear Investment Scenarios

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