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Investment Equilibrium Models under Emission Regulation and Different Energy Price Regimes

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Abstract

We consider an electricity market with two consumer segments subject to different price regimes. We formulate the problem of operations and investment in this market as a spatial equilibrium model where generators can invest in new capacity subject to different regional constraints. Transmission is organized according to a "flow based" approach as foreseen by Regulatory Authorities and System Operators in Europe. CO2 emissions are ruled by an overall cap and trade system where tradable allowances are auctioned. The consumer market in each region is decomposed in two segments: Energy Intensive Industries (EIIs) that participate in the cap and trade system and the rest of the market (N-EIIs). EIIs purchase electricity from dedicated base-load power plants at average cost prices, while N-EIIs are supplied at marginal cost. This organization, currently foreseen in some national laws in Europe, reflects a demand of European EIIs to partially mitigate the burden of emission charges and higher electricity prices due to CO2 regulation. We study two different types of long term average cost based contracts that differ by the organization of transmission. We present the models and discuss their policy implications through a case study applied to the Central Western European electricity market. Their mathematical properties are provided in Appendices. We first assess the impact of the EU-ETS on EIIs and other consumers. EIIs complain about its impact and argue that it can be mitigated through a combined action of the application of average cost based contracts, the

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elimination of the restrictions on nuclear plants and an improved access to the grid. We first investigate the impact to this better access to the grid by considering a first case with unlimited network resourses. In this case, both EIIs and N-EIIs benefit from investments in nuclear. When inglobing transmission constraints, the situation changes. Average cost based prices decrease generators' profits in a way that should reduce EIIs' electricity costs and also decreases overall welfare compared to pure marginal cost pricing. Possibly unexpected for EIIs, the application of long term average cost based contracts does not compensate them for the impact of the EU-ETS. This depends on the investment policies applied at national level. Only harmonization of nuclear investment policies at the European level could relieve EIIs from the EU-ETS burdens.

Keywords Average Cost Based Contracts, Energy Intensive Industries, EU-ETS, Investments.

JEL Classification C68, D61, L11, L60, Q40, Q51.

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Abstract

We consider an electricity market with two consumer segments subject to different price regimes. We formulate the problem of operations and investment in this market as a spatial equilibrium model where generators can develop new capacities subject to different regional constraints; transmission is organized on a flowgate basis and CO_2 emissions are ruled by an overall cap and trade system where tradable allowances are auctioned. The consumer market in each region is decomposed in two segments: Energy Intensive Industries (EIIs) that participate in the cap and trade system and the rest of the market (N-EIIs). EIIs purchase electricity from dedicated base-load power plants at average cost prices, while N-EIIs are supplied at marginal cost. This organization, currently foreseen in some national laws in Europe, reflects a demand of European EIIs to partially mitigate the burden of emission charges and higher electricity prices due to CO_2 regulation. We study two different types of long term average cost based contracts that differ by the organization of transmission. We present the models and discuss their policy implications through a case study applied to the Central Western European electricity market. We provide their mathematical properties in the e-companion of this paper.

Keywords: Average Cost Based Contracts, Energy Intensive Industries, EU-ETS, Investments.

1 Introduction

We consider an electricity market where sales are subject to two different price regimes. Some consumers procure electricity through long-term contracts at average cost based price; the others are supplied at marginal cost price. Arbitrage between the two market segments is impossible. Generators invest to satisfy demand in both market segments. The problem is motivated by proposals of European Energy Intensive Industries (hereafter EIIs) in reaction to the Cap and Trade system on CO_2 emission (the EU-ETS). EIIs argue that plants operating outside the EU are not today subject to similar legislations and face lighter emission constraints. This puts their European plants at a competitive disadvantage because they pay higher electricity prices and incur emission costs (Cefic [10], Business Europe [7]). Emission costs accrue from emission abatement and the purchase of allowances. Higher electricity costs derive from generators charging emission allowances in electricity prices at opportunity cost. EIIs accordingly threaten to relocate some of their facilities to more carbon lenient regions except for the introduction of measures mitigating this competitive disadvantage. This problem is related to the so called "carbon leakage" that we briefly introduce in Appendix A and EIIs largely invoke in their plea (Business Europe [6], [7]). We abstract away from the discussion of carbon leakage in this paper, but concentrate on what EIIs see as one of its causes namely the loss of competitiveness due to electricity costs.

EIIs find that "*today, electricity prices vastly exceed production costs most of the time and it is not exceptional that electricity prices are three times higher -or more- than average production costs*" (Cefic [10]). They attribute this high price not only to the EU-ETS, but also to "*malfunctioning energy markets*" that present "*three fundamental market deficiencies*": limited access to cross-border connections, the absence of a real competition in the power markets and the difficulties to find a correct policy to address the impact of the EU-ETS on electricity prices (Cefic [10]). They then detail measures that, in their opinion, would counter this high price.

The recourse to nuclear energy is the first measure envisaged by EIIs (Business Europe [3], [4]). This proposal does not require much presentation: nuclear investments are currently restricted in most of Europe and EIIs would like these restrictions removed. EIIs also recurrently explain that cross border should be facilitated so that they can access different suppliers in competition (Cefic [9], [10], Business Europe [5]). This position is more complex: in contrast with the good experience with nodal systems in the US, EIIs, like many in Europe favor pricing zones that they would like as large as possible (Bécret [1], [2]). Specifically IEFIC Europe ([16]) argued for an extended counter-trading to extend zones. EIIs also object to paying marginal energy and congestion costs. At least the objective of a more fluid cross border trade, if not the detail of their proposal, raises little objection. Much more controversial is EIIs' proposal to resort to long-term, cost based contracts for base load supplies (Cefic [10], Business Europe [5]). EIIs want long term, based contracts, for base load supplies. They argue for two "*transitional measures: (1) bilateral or multilateral cost-based Long-Term Contracts that ensure competitive energy prices and planning certainty; (2) base load from low-cost units*" (see Cefic [10]). The link between long term contracts and base load electricity is reasserted in (Businesseurope [5], Febeliec [14]). Incidentally for this paper EIIs recommend a strict application of competition law to reduce market power.

Our paper considers the impact of nuclear policy, cross-border trade and long-term contracts within the EU-ETS and whether they can heal EIIs difficulties. EIIs' proposals structure our models. Long-term cost-based contracts for base load constitute the more unusual point in EIIs proposals. They are true price discrimination but the manufacturing industry, that represented 17% of European GDP in 2007 (see Business Europe [8]), can certainly force these measures in the market and in the law (see the discussion of the French Exeltium consortium in Appendix B and the references therein). We accordingly segment the consumer market in two parts: one is ruled by average cost type contracts; the other is subject to marginal cost pricing. Except for this price discrimination that is a true departure from perfect competition, we assume that agents are price takers and generation is perfectly competitive and represented by a simple dispatch embedded in an investment model. Our models span a "region" decomposed into "zones". The EU-ETS is modeled by a maximum amount of allowances for the region. Different zonal nuclear policies can easily be represented by allowing or disallowing investments in this technology. Uneven policies induce EIIs to procure electricity from nuclear zones, which point to EIIs' concern about limitations to cross border trade. We treat this issue through a spatial model where pricing zones are linked by an electrical grid. We model extreme impacts of transmission organization by three couterfactuals. The first case assumes no limitation to cross border trade: the region is represented by a single node. This offers a reference to assess cross border trade limitations. The second counterfactual is obtained when EIIs procure electricity at a single price in the region. This is referred to as the regional contract scenario. In contrast, European authorities (competition and energy) and EIIs consistently repeat that the European power market is geographically segmented by nation (or smaller) and hence that cross border contracts are impossible. This justifies zonal average cost contracts which is our third counterfactual.

To the best of our knowledge, such considerations remain unusual in the literature. The closest we can think of is the Haiku model (see [19]) that analyzes the coexistence of average and marginal costs electricity systems in the regulated and restructured zones of the US. In contrast, we consider the two different pricing regimes in the same markets. Haiku and our model also differ numerically: Haiku finds the final equilibrium through an iterative process, while our models are solved as complementarity problems.

Besides policy relevance, we also believe that our models present some methodological interest. We do not discuss market power (market foreclosure) or long term risk hedging issues raised by long term contracts, but address a standard argument of electricity economics. After having been the most vocal advocates of the restructuring of the sector, EIIs now want to return to average cost pricing because they see marginal cost (and hence prices based on marginal costs) exceeding average generation costs, therefore creating rents that benefit generators and put them at competitive disadvantage. EIIs further argue that they mainly demand base load electricity whose full cost is lower than the average short run marginal cost price of restructured systems (let alone the long run marginal cost). These claims seem to contradict the standard result that equates long run marginal cost to short run marginal cost and average cost in optimally adapted systems. We shall see that policy and technological constraints can invalidate this result: pricing at long run average or marginal cost can then be quite different when some resources (here emission possibilities and transmission capabilities) are not adaptable. Average costs destroy convexity properties of the equilibrium problem and hence may also raise computational difficulties. We only mention the problem and briefly discuss it in Appendix H.

The paper is organized as follows. Section 2 provides a general description of the power market and the model. Section 3 details a reference model whose complementarity formulation and mathematical features are respectively discussed in Appendices D and E of the online e-companion. Section 4 concentrates on the average cost based models. Complementarity formulation and some mathematical characteristics of these models are given in the online Appendices F, G and H. Sections 5, 6 and 7 discuss the case study and explain the impact of average cost based contracts in different scenarios. Finally, we report our conclusions in Section 8.

2 The Power Market and General Modeling Considerations

2.1 Generation and demand

We consider a regional power market composed of different zones connected by an electric grid. Generators operate a set of plants in each zone. The representation of technologies is standard: each plant is characterized by its investment and operations costs as well as by its conversion efficiency and emission factors. There are existing capacities, but generators can also invest in new plants. There are two types of consumers in each zone, namely EIIs and other consumers (N-EIIs). They differ by the flexibility of their demand. Specifically, EIIs only demand base load electricity, while N-EIIs' demand can vary by time segment. The demand sectors are represented by linear demand curves. Hidalgo et al. [15] and Szabò [22] develop technological sectoral models of some of EIIs; further research should expand our models to include technological representations of EIIs.

2.2 The grid and the average cost contracts

Cross-border trade is a recurrent theme in EIIs' demand for base load electricity contracts. Transmission in Central Western Europe (CWE) currently relies on two pillars: (i) single price zones are linked by so called "transmission capacities", (ii) a separate Transmission System Operator (TSO)[1] controls each zone without any central authority in charge of cross-border trade. It is now about ten years that European Energy and Competition authorities document the barriers to trade created by this organization, albeit without addressing their causes (Smeers [20]). Recent movements promise some positive changes. A "market coupling" between France, Belgium and The Netherlands was introduced in 2006 to coordinates national PXs (see TenneT [23]). This is a real step forward even if it leaves the organisation of transmission untouched (see Oggioni and Smeers [18]). The Third Legislative Package[2] attempts to remedy this latter shortcoming and foresees more coordination among TSOs. Last, the introduction of a better representation of the grid (the "flow based model") has also been tried but has so far failed (see Smeers [20] for a more detailed discussion of the problem). Our representation of transmission assumes a positive outcome of these movements. Specifically, we assume that the operation of

[1] Transmission System Operator (TSO) is a company that is responsible for operating, maintaining and developing the transmission system for a control area and its interconnections. See ENTSO website.

[2] http://www.europeanenergyforum.eu/archives/european-union/eu-general-topic-file/eu-competition-and-economic-matters/third-legislative-package-on-eu-electricity-gas-markets

the grid moves away from "transmission capacities" and successfully implements a "flow based model" (see Appendix C) operated by fully coordinated TSOs (that can be assimilated to a single TSO) and PXs. Even this optimal outcome may not enable the level of cross border trade demanded by EIIs contracts. Zonal systems such as the flow-based model indeed have a long tradition of difficulties in meshed grids. ERCOT's flowgate system is probably what comes closest to the European "flow based" (see Duthaler and Finger [12]), but it encountered difficulties and will soon be abandoned in favour of a nodal system. There is thus today no theoretical or empirical evidence that the "flow-based model" devised in Europe, even though improving on the current situation, can provide the contractual security demanded by EIIs in the highly meshed system of CWE. This has implications that we model as follows. We consider a first scenario where the flow-based model enables EIIs to conclude regional average cost contracts as they desire (Cefic [10], Business Europe [5], Febeliec [14]). The zonal scenario assumes the opposite and restricts average cost contracts to remain zonal.

Summing up, we model transmission as a set of aggregate flowgates linking the zones of the regions and operated by a regional TSO. Electricity prices are zonal and embed congested costs computed on the aggregate flowgates between zones. This representation is used to build marginal cost and average cost pricing models. Following a common practice, we neglect grid losses.

2.3 The EU-ETS

The EU-ETS is a cap and trade system on CO_2 emissions: it applies to the power sector, refineries and the EIIs. The system has been extensively described in the literature and needs no reminder here. The carbon market is modeled by an emission constraint where the total cap E is computed on the basis of data taken from the Community Independent Transaction Log (CITL)[3]. We assume an emission market restricted to the sole power sector (we do not model an endogenous participation of EIIs in that market). This reductive assumption is due to the absence of technological modeling of EIIs. It also simplifies the model and concentrates the discussion on the impact of differentiated national generation policies and cross-border trade on the EIIs' proposal. We assume full auctioning of allowances. Emission factors of generation technologies come from Davis and URS [11].

2.4 General economic assumptions

Agents are price takers in most of the paper. The average cost contracts are the exception to that blanket assumption: they can indeed be seen as the result of a bargaining between EIIs and generators or as a legal obligation akin to a regulation. We take average cost pricing as an exogenous market imperfection and assume marginal cost pricing elsewhere. The existence of two pricing regimes is a true price discrimination and hence a departure from perfect competition.

All models involve three commodity or service markets (energy, emissions and transmission) and four types of agents (generators, EIIs and N-EII and the regional TSO). We consider a time horizon of one year. We simplify the discussion by decomposing electricity demand into two

[3]Community Independent Transaction Log. 2008-2012. Available at http://ec.europa.eu/environment/climat/emission/citl_en_phase_ii.htm.

time segments, peak and off peak. EIIs' consumption is price sensitive but constant over the year. The model is single stage; generators build and operate capacity in a single period (here one year) where they also incur annual investment and operations costs. This standard static formulation assumes that new power plants are immediately available when built. Following Stoft [21], we conduct the discussion on an hourly basis or in MWh and express capacities in MWh and not in MW.

2.4.1 Perfect competition models

The reference model assumes full marginal cost pricing and is presented in Section 3. It describes a perfectly competitive market where generators invest and operate their plants to maximize the profits accruing from supplying the two consumer groups, consumers maximize their surpluses and the TSO maximizes the profit from selling flowgate services[4]. Allowance prices are equal to the generators' marginal cost of emission reduction.

2.4.2 Average cost models.

Average cost models segment the market and introduce different pricing schemes for the two consumer groups. They are described in Section 4. EIIs buy electricity at average cost through long-term contracts and N-EIIs still pay marginal cost based electricity price. This requires a change of generators' model: they still maximize the profits from supplying N-EIIs, but minimize the cost of supplying EIIs. As explained above, we consider both regional and zonal average cost prices.

2.5 Model presentation

For the sake of simplicity, models are stated in agent's optimization and market clearing form, or through accounting relations. The alternative mixed complementarity forms are given in Appendices D, F and G and are used for solving the problems (using PATH in GAMS). The mathematical programming formalism makes it easy to modify and extend the models.

3 The perfect competition model

The model assumes marginal cost pricing throughout. It is equivalent to a welfare maximization problem and would therefore be equivalent to a nodal system if zones reduced to nodes. The model is a reference for the rest of the analysis (see Appendix E for some properties).

3.1 Notation of the Reference Model

3.1.1 Notation

Sets

[4]It is worthwhile recalling here the former, controversial, discussions about the assumption of the TSO's profit maximization (see Boucher J., Y. Smeers. 2001. Alternative models of restructured electricity systems. Part 1: no market power. *Operations Research* **49** 821-838 for a modeling view on the subject).

- $i \in I$ Zones;
- $f \in F$ Generators;
- $l \in L$ Flowgates;
- $t \in T$ Time segments;
- $k \in K$ Technology;

Parameters

- $X_{f,i,k}$ Existing generation capacity of technology k run by generator f in zone i (MWh);
- $I_{f,i,k}$ Unitary hourly investment/capacity costs of technology k run by generator f in zone i (€/MWh);
- $c_{f,i,k}$ Production costs of technology k run by generator f in zone i (€/MWh);
- τ_t Duration in % of time segment t;
- a_i^1; b_i^1 Intercept and slope of EIIs' demand function in zone i (€/MWh) and (€/MWh^2);
- $a_{i,t}^2$; $b_{i,t}^2$ Intercept and slope of N-EIIs' demand function in zone i, time segment t (€/MWh) and (€/MWh^2);
- $Linecap_l$ Capacity of flowgate l (MWh);
- $PTDF_{i,l}$ Power Transfer Distribution Factor matrix defining the flow in flowgate l due to a unit injection in zone i with corresponding withdrawal at the hub (see Appendix C);
- e_k; E Emission factor by technology k (ton/MWh) and emission cap in ton per hour.

Variables:

- $x_{f,i,k}$ New capacity of technology k used by generator f in zone i (MWh);
- $y_{f,i,k,t}$ Production of generator f by technology k in zone i, time segment t (MWh);
- $P^1(d_i^1, i)$ EIIs' inverse demand function in zone i (€/MWh);
- $P^2(d_{i,t}^2, i, t)$ N-EIIs' inverse demand function in zone i, time segment t (€/MWh);
- d_i^1 EIIs' demand in zone i (MWh);
- $d_{i,t}^2$ N-EIIs' demand in zone i, time segment t (MWh);
- π_t Electricity price at the hub in time segment t (€/MWh);
- $p_{i,t}$ Marginal electricity price in zone i, time segment t (€/MWh);
- $\mu_{l,t}^{+,-}$ Congestion rent of flowgate l, depending on flow direction $(+,-)$ and time segment t (€/MWh);
- $\nu_{f,i,k,t}$ Marginal hourly value of capacity (scarcity rent) of technology k used by generator f in zone i, time segment t (€/MWh).

Most variables depend on time t but EIIs' electricity consumption is constant over the year and hence time independent. Inverted demand functions (price as function of quantities) refer to one hour periods and are affine: $P^2_{i,t}(d^2_{i,t}) = a^2_{i,t} - b^2_{i,t}d^2_{i,t}$ for N-EIIs and $P^1_i(d^1_i) = a^1_i - b^1_i d^1_i$ for EIIs.

3.2 Agents' Models

3.2.1 Generators

Generators invest in new capacities and operate both existing and new plants so as to maximize hourly profits within their capacity constraints over time segment t:

$$\mathbf{Max}_{\mathbf{y_{f,i,k,t};x_{f,i,k}}} \quad \sum_{i,k,t} p_{i,t} \cdot y_{f,i,k,t} \cdot \tau_t - \sum_{i,k,t}(c_{f,i,k} + e_k \cdot \lambda) \cdot y_{f,i,k,t} \cdot \tau_t - \sum_{k,i} I_{f,i,k} \cdot x_{f,i,k} \quad (1)$$

$$s.t. \qquad 0 \leq X_{f,i,k} + x_{f,i,k} - y_{f,i,k,t} \qquad (\nu_{f,i,k,t}) \quad \forall\ f,i,k,t \quad (2)$$

$$0 \leq x_{f,i,k}, \quad y_{f,i,k,t} \quad (3)$$

The dual variable $\nu_{f,i,k,t}$ of the capacity constraint (2) represents the scarcity rent, i.e. the marginal capacity value, of both new and existing power plants. The zonal electricity prices $p_{i,t}$ and allowance price λ are given to generators, but are endogenous to the problem.

3.2.2 N-EIIs and EIIs

N-EIIs' maximize hourly surplus in each time segment t and zone i:

$$\mathbf{Max}_{\mathbf{d^2_{i,t}}} \quad \sum_t \left[\int_0^{d^2_{i,t}} P^2_{i,t}(\xi)d\xi - p_{i,t} \cdot d^2_{i,t}\right] \cdot \tau_t \quad (4)$$

Recall that N-EIIs can adapt their consumption through the year (here only two periods) and industrial electricity consumption is constant over time. The EIIs' model becomes:

$$\mathbf{Max}_{\mathbf{d^1_i}} \quad \int_0^{d^1_i} P^1_i(\xi)d\xi - \sum_t \tau_t \cdot p_{i,t} \cdot d^1_i \quad (5)$$

Electricity consumptions ($d^2_{i,t}$) and (d^1_i) are non-negative. Both consumer groups pay identical electricity prices $p_{i,t}$. These prices are exogenous for consumers but endogenous to the problem.

3.2.3 TSO's profit maximization and clearing of the transmission market

Energy injections ($\sum_k y^t_{i,k,t}$) and withdrawals ($d^1_i + d^2_{i,t}$) maximize the TSO's profit for the given prices $p_{i,t}$.

$$\mathbf{Max}_{\mathbf{d^1_i;d^2_{i,t};y_{f,i,k,t}}} \quad \sum_{i,t} \tau_t \cdot p_{i,t} \cdot (d^1_i + d^2_{i,t} - \sum_{f,k} y_{f,i,k,t}) \quad (6)$$

$$s.t. \qquad -\mathit{Linecap}_l \leq \sum_i PTDF_{i,l}(\sum_{f,k} y_{f,i,k,t} - d^1_i - d^2_{i,t}) \leq \mathit{Linecap}_l \qquad (\mu^{\pm}_{l,t}) \quad \forall\ l,t \quad (7)$$

$$\sum_i(\sum_{f,k} y_{f,i,k,t} - d^1_i - d^2_{i,t}) = 0 \qquad (\tau_t\pi_t) \quad \forall\ l,t \quad (8)$$

The KKT conditions of the TSO's problem imply that π_t is the electricity price at the hub in each time t. As in the generators and consumers' models the $p_{i,t}$ are the zonal electricity prices. The dual variables $\mu_{l,t}^{+}$ and $\mu_{l,t}^{-}$ are the marginal values of the upper and lower transmission constraints respectively. They are the congestion prices charged by the TSO for the use of flowgate capacity. $\mu_{l,t}^{+}$ and $\mu_{l,t}^{-}$ are directly passed into the zonal electricity price received by generators or paid by consumers. The KKT conditions also relate the zonal electricity prices $p_{i,t}$, the price at the hub π_t and congestion costs $\mu_{l,t}^{\pm}$ and express the clearing of the transmission service market.

3.2.4 Clearing of the energy market

The energy market clears at the hub in each time segment t at price π_t. This is expressed by (8) in the TSO's problem.

3.2.5 Clearing of the emission market

The emission market clears on an hourly basis, over the two time segments:

$$0 \leq E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y_{f,i,k,t} \qquad (\lambda) \tag{9}$$

Total hourly emissions are computed by multiplying the technology emission factor e_k by the hourly electricity production $y_{f,i,k,t}$. The dual variable λ is the market price of emission allowance.

4 Average Cost Pricing Models

The consumer market is divided into the EIIs and N-EIIs segments. N-EIIs pay marginal cost as in the perfect competition model of Section 3, but electricity is sold to EIIs at average cost. Supplies to EIIs are zonal in the zonal contract and the electricity price is equal to average generation and emission allowance costs in the zone at the exclusion of any transmission cost. Supplies to EIIs involve cross border trade in the regional contract and EIIs pay average generation, emission and transmission cost for all their regional electricity consumption sites. Because average costs need to be auditable, we assume in both cases that they are based on capacities dedicated by generators to EIIs; the rest of the capacity supplies N-EIIs. The allocation of existing capacity or investment in new capacity to both market segments is taken up in Section 4.4 and in Appendix F.

4.1 Notation of the Average Cost Models

We list the variables and recall the parameters of Section 3.1. EIIs and N-EIIs' variables are respectively noted "*1*" and "*2*". Again, EIIs' variables do not depend on time.

Parameters

- $X_{f,i,k}$ Existing generation capacity of technology k run by generator f in zone i (MWh);

- $I_{f,i,k}$ Unitary hourly investment/capacity costs of technology k run by generator f in zone i (€/MWh);
- $c_{f,i,k}$ Production costs of technology k run by generator f in zone i (€/MWh);
- τ_t Duration in % of time segment t;
- a_i^1; b_i^1 Intercept and slope of EIIs' demand function in zone i (€/MWh) and (€/MWh^2);
- $a_{i,t}^2$; $b_{i,t}^2$ Intercept and slope of N-EIIs' demand function in zone i, time segment t (€/MWh) and (€/MWh^2);
- $Linecap_l$ Capacity of flowgate l (MWh);
- $PTDF_{i,l}$ Power Transfer Distribution Factro matrix defining the flow in flowgate l due to a unit injection in zone i with corresponding withdrawal at the hub (see Appendix C);
- e_k; E Emission factor by technology k (ton/MWh) and emission cap in ton per hour.

Variables

- $y_{f,i,k}^1$; $y_{f,i,k,t}^2$ Hourly generation by technology k run by generator f in zone i to supply EIIs and N-EIIs (MWh);
- $X_{f,i,k}^1$; $X_{f,i,k}^2$ Existing capacity of technology k that generator f in i dedicates to EIIs and N-EIIs (MWh);
- $x_{f,i,k}^1$; $x_{f,i,k}^2$ New capacity of technology k that generator f in i dedicates to EIIs and N-EIIs (MWh);
- $\nu_{f,i,k}^1$; $\nu_{f,i,k,t}^2$ Marginal hourly value of capacity (scarcity rent) of technology k used by generator f in zone i allocated to EIIs and N-EIIs (€/MWh);
- $\nu_{f,i,k}$ Marginal hourly value of capacity of technology k used by generator f in zone i (€/MWh). See below for the relation with $\nu_{f,i,k}^1$ and $\nu_{f,i,k,t}^2$;
- d_i^1; $d_{i,t}^2$ Hourly power consumption respectively by EIIs and N-EIIs in zone i (in MWh). N-EIIs' consumption differs by season t;
- p^1 Regional average cost price of electricity paid by EIIs (€/MWh). This price is the sum of the regional production and allowance costs $pprod^1$ and of the average regional transmission cost $ptrans^1$;
- p_i^1 Zonal average cost price of electricity paid by EIIs (€/MWh). This price in the sum of the regional production and allowance costs in i;
- $p_{i,t}^2$ Zonal marginal price paid by N-EIIs in each season t (€/MWh);
- π_t^2 Electricity price at the hub in time segment t for N-EIIs (€/MWh);
- θ^1; θ_i^1 Marginal cost at the hub of the electricity generated by capacities dedicated to EIIs (€/MWh) respectively in the regional and in the zonal average cost price models. θ_i^1 depends on zone i.

4.2 Regional Average Cost Pricing Model

The regional average cost contract assumes that EIIs form a power purchase consortium that buys electricity produced by dedicated plants located in different zones of the network through long-term contracts. This is akin to the French Exeltium consortium (see Appendix B) but extended to a multinational region. The N-EIIs' problem remains unchanged.

4.2.1 Generators maximize profits of supplying N-EIIs

The N-EII sector is still supplied at marginal cost. As in Section 3.2.1, generators maximize the profits accruing from supplying N-EIIs over time segment t at the prevailing electricity and allowance prices $p^2_{i,t}$ and λ.

$$\mathbf{Max}_{\mathbf{y^2_{f,i,k,t}};\mathbf{x^2_{f,i,k}}} \quad \sum_{i,k,t} p^2_{i,t} \cdot y^2_{f,i,k,t} \cdot \tau_t - \sum_{i,k,t} (c_{f,i,k} + e_k \cdot \lambda) \cdot y^2_{f,i,k,t} \cdot \tau_t - \sum_{k,i} I_{f,i,k} \cdot x^2_{f,i,k} \tag{10}$$

$$s.t. \qquad 0 \leq X^2_{f,i,k} + x^2_{f,i,k} - y^2_{f,i,k,t} \qquad (\nu^2_{f,i,k,t}) \quad \forall\ f,i,k,t \tag{11}$$

$$0 \leq X^2_{f,i,k}, \quad x^2_{f,i,k}, \quad y^2_{f,i,k,t} \tag{12}$$

4.2.2 Generators minimize the cost of supplying EIIs

A different model applies for generation and supply to the EIIs' segment. The intent of EIIs is that generators compete to supply them on the basis of the average cost of the plants that they operate. The practical organization of that system is far from clear, but it is easy to construct a counterfactual that represents the best that EIIs can hope for. Because EIIs demand a regional price, we assume a power system where small homogeneous consortia of generators located throughout the region compete to offer "all in" average cost contracts. Generation consortia are homogeneous and hence have the same cost structure; the outcome of that market is identical to the one where a single generator supplies the EIIs of the region at minimum cost. This is stated as follows:

$$\mathbf{Min}_{\mathbf{y^1_{f,i,k}};\mathbf{x^1_{f,k,i}}} \quad \sum_{f,i} (c_{f,i,k} + e_k \cdot \lambda) \cdot y^1_{f,i,k} - (\sum_{i,l,t} \tau_t \cdot PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l)) \cdot (\sum_{f,k} y^1_{f,i,k} - d^1_i) \tag{13}$$

$$+ \sum_{f,k,i} I_{f,i,k} \cdot x^1_{f,k,i}$$

$$s.t. \qquad 0 \leq X^1_{f,i,k} + x^1_{f,i,k} - y^1_{f,i,k} \qquad (\nu^1_{f,i,k}) \quad \forall\ f,i,k \tag{14}$$

$$\sum_{f,i} y^1_{f,i} - \sum_{i} d^1_i = 0 \quad (\theta^1) \tag{15}$$

$$0 \leq X^1_{f,i,k}, \quad x^1_{f,i,k}, \quad y^1_{f,i,k} \tag{16}$$

The expressions $(c_{f,i,k} + e_k \cdot \lambda)$ and $(\sum_{i,l,t} \tau_t \cdot PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l))$ are respectively the sum of production and emission costs and the congestion costs of sales to EIIs. These take place at the regional average cost p^1 that accounts for both production and emission ($pprod^1$) and transmission ($ptrans^1$) costs. Condition (17) computes $pprod^1$ that includes the annual fuel, emission and capacity costs of the existing ($X^1_{f,i,k}$) and new ($x^1_{f,i,k}$) power plants assigned to EIIs. Adding average production and transmission costs gives the price p^1 paid by EIIs (19).

$$pprod^1 = \frac{\sum_{f,i,k} y^1_{f,i,k} \cdot (c_{f,i,k} + e_k \cdot \lambda) + \sum_{f,i,k} I_{f,i,k} \cdot (X^1_{f,i,k} + x^1_{f,i,k})}{\sum_i d^1_i} \tag{17}$$

$$ptrans^1 = \frac{\sum_{i,l,t}(\tau_t \cdot PTDF_{i,l}(\mu_l^{t,+} - \mu_l^{t,-}) \cdot (\sum_{f,k} y^1_{f,i,k} - d^1_i))}{\sum_i d^1_i} \tag{18}$$

$$p^1 = pprod^1 + ptrans^1 \tag{19}$$

4.2.3 N-EIIs and EIIs maximize surpluses

As in the reference case, both N-EIIs and EIIs maximize their surpluses. The formulation of the N-EIIs' problem is as in Section 3.2.2 after substituting $p_{i,t}$ with $p^2_{i,t}$. The new EIIs' problem is adapted from condition (5) and becomes

$$\mathbf{Max}_{\mathbf{d^1_i}} \quad \int_0^{d^1_i} P^1_i(\xi) d\xi - p^1 \cdot d^1_i \quad \forall\ i \tag{20}$$

after replacing the weighted sum of the marginal electricity prices $\sum_t \tau_t \cdot p_{t,i}$ by p^1 defined in (19).

4.2.4 TSO's profit maximization and clearing of the transmission market

The TSO's model is obtained from conditions (6) and (7) after replacing the variable $y_{f,i,k,t}$ by the sum of $y^1_{f,i,k}$ and $y^2_{f,i,k,t}$ to account for the segmentation of the market into EIIs and N-EIIs.

4.2.5 Clearing the energy market

The model clears two energy markets. The balance equations are stated in (15) and (21) for the EIIs and N-EIIs respectively.

$$\sum_{f,i,k} y^2_{f,i,k,t} - \sum_i d^2_{i,t} = 0 \quad (\pi^2_t) \quad \forall\ t \tag{21}$$

The dual variable θ^1 of relation (15) is the marginal cost, at the hub, of the energy delivered to EIIs (see the proof of Corollary 1 in Appendix F). The EIIs' market thus involves two prices: θ^1 is the marginal cost of a production efficient supply to EIIs; p^1 is an "accounting" average cost price of a possibly allocative inefficient supply to EIIs (see Appendix F for a deeper discussion).

4.2.6 Clearing the emission market

The clearing condition derives from (9) after replacing $\sum_{f,i,k,t} \tau_t \cdot e_k \cdot y_{f,i,k,t}$ with the emissions from EIIs ($\sum_{f,i,k} e_k \cdot y^1_{f,i,k}$) and N-EIIs ($\sum_{t,f,i,k} e_k \cdot y^2_{f,i,k,t}$).

4.3 Zonal Average Cost Pricing Model

The zonal average cost model represents a situation where transmission does not permit the cross border contracts demanded by EIIs. The N-EIIs' model is unchanged, but the EIIs' problem requires that EIIs only contract with local generators. The average cost thus boils down to the zonal average generation (capacity, fixed and variable operating and fuel) and CO_2 costs.

4.3.1 Transmission market and TSO's profit maximization

Because EIIs only contract with local generators, their demand no longer contributes to network congestion. It therefore disappears from the TSO's optimization problem that now accounts only for the demand and production variables of N-EIIs.

4.3.2 Generators minimize the cost of supplying EIIs

We assume a purchasing consortium in each zone. Generators therefore solve the following zonal cost minimization problem:

$$\mathbf{Min}_{\mathbf{y^1_{f,i,k}};\mathbf{x^1_{f,i,k}}} \quad \sum_{f,k,i}(c_{f,i,k} + e_k \cdot \lambda) \cdot y^1_{f,i,k} + \sum_{f,k,i} I_{f,k,i} \cdot x^1_{f,k,i} \tag{22}$$

$$s.t. \qquad 0 \leq X^1_{f,i,k} + x^1_{f,i,k} - y^1_{f,i,k} \qquad (\nu^1_{f,i,k}) \quad \forall\ f, i, k \tag{23}$$

$$\sum_f y^1_{f,i} - d^1_i = 0 \ \ (\theta^1_i) \qquad \forall\ i \tag{24}$$

They then sell electricity to zonal EIIs at the price p^1_i:

$$p^1_i = \frac{\sum_{f,k} y^1_{f,i,k} \cdot (c_{f,i,k} + e_k \cdot \lambda) + \sum_{f,k} I_{f,i,k} \cdot (X^1_{f,i,k} + x^1_{f,i,k})}{d^1_i} \tag{25}$$

that comprises variable and fixed production related costs, but no transmission cost.

4.3.3 EIIs maximize surpluses

The EIIs' maximization problem is obtained from Section 4.2.3 after substituting the regional (p^1) with the zonal (p^1_i) average cost prices:

$$\mathbf{Max}_{\mathbf{d^1_i}} \qquad \int_0^{d^1_i} P^1_i(\xi)d\xi - p^1_i \cdot d^1_i \quad \forall\ i \tag{26}$$

4.3.4 Clearing the energy market

The N-EIIs' market clears on a regional basis: the model is identical to the one of Section 4.2.5. The EIIs market clears on a zonal basis as stated in (24). The θ^1_i are zonal marginal costs of supplies to EIIs and hence depend on the zone i.

4.3.5 Clearing the emission market

Finally, the clearing of the emission market is identical to that described in Section 4.2.6.

4.4 Allocation of capacity between EIIs and N-EIIs

Market segmentation requires generators to allocate their existing and new capacity to the two consumer groups. We make this allocation efficient (and profit maximizing for the generators) by equalizing the marginal values of the capacity dedicated to EIIs and N-EIIs. The interpretation of this condition is obvious: equalizing marginal values capacities is profit maximizing (and welfare maximising in perfect competition) when there are no economies of scale. This holds true both for existing and new capacities. The dual variables $\nu^2_{f,i,k,t}$ and $\nu^1_{f,i,k}$ directly measure the marginal profit (the marginal social value in perfect competition) accruing from the capacities supplying EIIs and N-EIIS respectively. Forcing the equality of the marginal values of capacity for the two consumer groups can only be done on the complementarity formulation as explained in Appendix F for the regional model. A similar reasoning applies to the zonal average cost model.

5 Prototype case study

We apply these models on the stylized representation of the Central Western European (CWE) power market depicted in Figure 1. This simplified view of the system comprises fifteen zones distributed over four countries: Germany, France, Belgium and the Netherlands. Electricity production and consumption activities are aggregated in 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 French zones are only used to transfer electricity. The grid is modeled through the flowgate approach described above with zones connected by 28 flowgates with limited capacity. The $PTDF$ matrix, not reported here, is taken from ECN [13]. The main German zone is the hub.

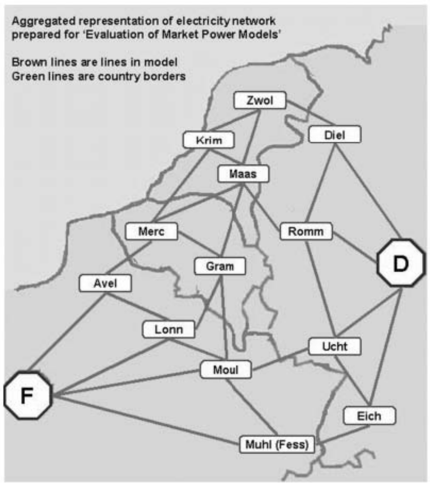

Figure 1: Central Western European Power Market

We consider seven different technologies: hydro, wind, nuclear, lignite, coal, CCGT and old oil based plants. These operate in the merit order determined by the (exogenous) fuel costs and the (endogenous) carbon and transmission prices. Wind capacities are taken from EWEA[5], while data for the other technologies are provided by ENTSO[6] and Eurostat[7].

Electricity is generated by existing and 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 allow one to change this assumption and apply different efficiency rates to new plants. Doing so in this prototype study would however mix fundamental economic phenomena and sometimes arbitrary data differentiations and hence cloud the interpretation of the results.

Different pricing regimes apply to N-EIIs and EIIs. N-EIIs pay zonal marginal cost prices determined on the wholesale market (that is neglecting network constraint in the zone), while EIIs pay either regional or zonal average cost based prices through long term contracts. The regional contract implies a unique average cost price for all EIIs independently of their location. In contrast, the zonal contracts imply seven average cost prices, one per each active zone. As explained in Section 2, we describe both consumer groups through linear demand functions and leave the introduction of a technological representation to future research. These demand functions are affine and constructed by setting a reference power price of 70 €/MWh[8], a reference demand selected from Eurostat[9] and ENTSO[10] and reference elasticity values of -0.1 and -1 respectively for N-EIIs and EIIs. The -1 value is taken from Newbery [17]. It may appear high (recall that it is meant to be a long run price elasticity), but our goal is to get insight into the way cost based contracts mitigate the impact of the EU-ETS on EIIs' demand (which includes an incentive to relocate activities). The elasticity thus reflects a combination of conservation and relocation effects that we are not in a position to differentiate in this paper. The exact value of the elasticity is thus less important in that context; still we tested an alternative elasticity value at -0.8 that did not change the conclusion of our analysis. The study is conducted on one year subdivided into two sub-periods: the so-called summer or off-peak lasts 5136 hours and winter or peak extends over 3624 hours. We are thus effectively working with the base-load demand of each consumer group in winter and in summer. Demand is differentiated by zone. As observed in CWE, N-EIIs have a higher power demand in winter than in summer. EIIs' power demand is constant as this is one of the reasons that EIIs invoke in order to justify separate contracts over the year.

We account for the desire of EIIs to see nuclear energy in the generation portfolio by conducting the analysis in three stages. A first stage looks at the problem for 2008 conditions and fixed capacities (08FC hereafter). This corresponds to the current request of the EIIs to have access to a share of the existing nuclear generating capacity. The second stage considers the year 2020 and assumes the extension of today's policy that only allows for CWE nuclear

[5] Wind capacity data are available at
http://www.ewea.org/fileadmin/ewea_documents/documents/statistics/cumulative_wind_per_ms_1998_2009_ws.xls

[6] See "Net generating capacities and inventory" available at https://www.entsoe.eu/index.php?id=182

[7] See "Infrastructure-electricity-annual data" available at
http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database

[8] See http://www.eex.com/en

[9] See "Consumption of electricity by industry, transport activities and households/services". Available at http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/main_tables.

[10] See "Monthly Consumption of a specific country for a specific range of time". Available at https://www.entsoe.eu/index.php?id=92.

investments in France (20IFR hereafter). The third stage assumes that discussions in Germany evolve in a way that makes it possible to also invest in nuclear capacity in that country by the year 2020: nuclear investments are thus possible both in France and in Germany (20IDEFR hereafter). We run four scenarios for each stage: NETS-R is the pure marginal cost pricing as if the EU-ETS did not exist; R is the marginal cost pricing with the EU-ETS. RAC and ZAC are respectively the Regional and Zonal Average Cost counterfactuals with EU-ETS. The year 2020 is selected because it corresponds to the end of the third ETS phase. Reference demand and generation capacity data are constructed on the basis of 2008 values. To model the 2020 scenarios, we increase the 2008 reference demand by 12% (assuming a low yearly growth rate of less than 1%). We also raise wind capacity available for 2008 by 15% in order to accommodate the Commission target of 20% renewables energy production by 2020 (not all renewable energy will come from wind and it is not certain that the target will be met). We also modify the annual emission cap imposed on the CWE energy sector in the phase 2008-2012 taking into account the CO_2 reduction foreseen by the EU Commission[11]. Moreover, in order to evaluate EIIs' complains about the inefficiencies of the transmission system, we first run all these scenarios by assuming no capacity limits for the grid and then by making these limits binding. The results are respectively discussed in Sections 6 and 7. Finally, Appendix J reports in Tables the main reference data used in our simulations.

6 The single node market

EIIs take the EU-ETS as a given policy but wish to resort to nuclear energy for their base load supply in order to mitigate its effect. At the same time they want enhanced cross border trade possibilities, at least for accessing nuclear energy in the zones where it can develop, at best to put generators in competition. A single node model of the region is a very extreme case where limitations to cross border trade disappear. We first briefly assess EIIs proposals when there are no transmission constraints. Needless to say average cost contracts boil down to the sole regional contract in a single node region.

TWh	**N-EIIs**			**EIIs**		
	FC	**20IFR**	**20IDEFR**	**FC**	**20IFR**	**20IDEFR**
NETS_R	699	811	812	480	719	733
R	697	811	812	421	719	733
RAC	652	811	812	536	743	771

Table 1: N-EIIs and EIIs' global demand in the different scenarios

Table 1 gives the total N-EIIs and EIIs' demand in the different scenarios. We concentrate on the EIIs. Consider first the case with fixed capacities 08FC. The impact of the EU-ETS is quite clear: EIIs' demand drastically decreases. The impact of the average cost contract is also striking. Demand jumps to a value higher than before the inception of the EU-ETS. This certainly explains EIIs' requests. By paying the average base load generation cost, they

[11]See "Commission Decision of 9 July 2010 on the Community-wide quantity of allowances to be issued under the EU Emission Trading Scheme for 2013" available at http://ec.europa.eu/environment/climat/emission/pdf/dec_4658.pdf

avoid both CO_2 allowances and benefit from the cheapest generation mode. Not only do they overcome the high electricity cost, but they appropriate part of the scarce nuclear resources.

Consider now the case where nuclear investments are allowed in France (20IFR). Because there is no transmission constraint, all EIIs can procure nuclear capacity from France (at least in the model). The consequences are significant: the EU-ETS has no impact anymore whether on N-EIIs or EIIs. The reason is simple: the price of CO_2 drops to zero. But the average cost contracts are still beneficial to EIIs. This may look surprising to the extent that a zero CO_2 price and the absence of any transmission constraint suggest that the usual economic argument of equality of long run marginal and average cost of optimal systems should apply here implying that there should be no difference of results between the marginal and average cost models. But the demand of EIIs makes that reasoning moot: EIIs do not demand to pay the average generation cost, but average base load generation cost. The usual reasoning therefore does not apply with the result that EIIs benefit from these special contracts beyond what is necessary to compensate for the impact of the EU-ETS (which is here null).

Not surprisingly the same type of result applies when nuclear investments are allowed both in France and Germany.

It would seem that these results should comfort EIIs in their demand. By improving on cross-border trade and allowing for nuclear energy, the average cost contract, not only compensate them from the EU-ETS, but nuclear suffices to eliminate any EU-ETS burden and the average cost contract allows them to benefit from discriminatory pricing. The question is whether these properties remain when transmission constraints are taken into account. As the following section shows, transmission blurs the whole picture. While nuclear can still heal EIIs, average cost contracts, combined with the sole zonal development of nuclear, lose a lot of their potential.

7 The impact of transmission constraints

Recall that average cost based contracts are intended to mitigate the impact of the EU-ETS on EIIs' electricity costs. We first give a global view and then turn to some analysis. Recall that transmission constraints impose limits in cross-border exchanges and make the market zonal.

7.1 A global view

Total electricity demand by EIIs under the different policies gives a first view of the effectiveness of the average cost contracts. Results are reported in Table 2. As expected, comparing the NETS_R and the R cases in Table 3, one observes that the inception of the EU-ETS significantly reduces EIIs' electricity demand in 08FC and in the 20IFR models. Contrarily, the reduction is much smaller in the 20IDEFR case.

The welfare information reported in Tables 4 and 5 gives an alternative view of the phenomenon, but confirms the findings. The EIIs' welfare dramatically decreases in the fixed capacity and French nuclear only cases. In contrast, the welfare loss is much more modest when nuclear investments are also allowed in Germany.

But in contrast with EIIs' expectations, both demand and welfare tables also reveal that average cost contracts only offer a very limited remedy whether in the fixed capacity or French nuclear only cases. Again, the situation improves in the 20IDEFR scenario. The following

TWh	**N-EIIs**			**EIIs**		
	FC	**20IFR**	**20IDEFR**	**FC**	**20IFR**	**20IDEFR**
NETS_R	700	803	810	489	656	715
R	696	782	807	409	473	693
RAC	683	782	801	414	553	713
ZAC	673	782	807	456	557	722

Table 2: N-EIIs and EIIs' global demand in the different scenarios

MWh	**DE**			**FR**		
	08FC	**20IFR**	**20IDEFR**	**08FC**	**20IFR**	**20IDEFR**
NETS_R	26,381	36,678	43,283	22,002	26,154	26,154
R	18,741	21,792	44,056	21,849	25,052	25,697
RAC	23,834	31,894	41,097	15,325	20,508	26,425
ZAC	20,047	26,893	44,651	24,738	28,217	28,255
MWh	**BE**			**NL**		
	08FC	**20IFR**	**20IDEFR**	**08FC**	**20IFR**	**20IDEFR**
NETS_R	3,644	5,776	5,773	3,823	6,307	6,394
R	2,936	3,347	4,284	3,185	3,762	5,085
RAC	3,861	5,168	6,659	4,189	5,606	7,224
ZAC	4,272	4,659	4,864	2,955	3,790	4,669

Table 3: EIIs' hourly demand in the different scenarios

Billion €	**NETS_R**			**R**		
	08FC	**20IFR**	**20IDEFR**	**08FC**	**20IFR**	**20IDEFR**
EIIs	19.84	28.25	32.49	14.23	16.60	30.79
N-EIIs	239.86	280.65	285.81	236.58	266.74	283.97
Consumers	**259.70**	**308.90**	**318.30**	**250.81**	**283.34**	**314.76**
Generators	63.83	51.14	44.82	52.02	47.89	39.41
Allowances				17.02	17.17	7.12
TSO	1.02	0.62	0.83	2.01	2.00	1.73
Welfare	**324.55**	**360.66**	**363.95**	**321.86**	**350.41**	**363.02**

Table 4: Welfare under the NETS_R and the R scenarios

Billion €	**RAC**			**ZAC**		
	08FC	**20IFR**	**20IDEFR**	**08FC**	**20IFR**	**20IDEFR**
EIIs	11.02	17.62	29.26	14.87	19.06	30.67
N-EIIs	227.91	266.85	279.44	222.17	266.70	283.36
Consumers	**238.93**	**284.47**	**308.70**	**237.04**	**285.76**	**314.03**
Generators	48.73	43.62	38.18	55.43	44.95	39.31
Allowances	29.13	18.32	13.54	26.03	17.50	7.99
TSO	2.45	2.20	1.87	3.02	2.07	1.69
Welfare	**319.24**	**348.61**	**362.29**	**321.52**	**350.28**	**363.02**

Table 5: Welfare under the RAC and ZAC scenarios

provides some intuition to these results. We first discuss the impact of the EU-ETS and then turn to the average cost remedies.

7.2 The impact of the EU-ETS

The decrease of EIIs' electricity demand as a result of the introduction of the EU-ETS is not a surprise. This is one of the intended consequences of the CO_2 policy, at least as long as it does not imply a relocation of EIIs' activities. A shift in generation mix towards less carbon intensive fuels is the other intended effect. Because renewable still needs to be subsidized today, their development is exogenous in this work. Substitution toward gas and nuclear are thus the only remaining possibilities on the generation side to reduce emissions. This can obviously not take place in FC08 when capacities are given, but one would expect to see it on a large scale in 2020. Comparing the NETS_R and the R cases in the 20IFR scenario (see Tables 6 and 7 in Appendix I), a possibly surprising result is that the EU-ETS induces a decrease of nuclear investments. In principle, the EU-ETS implies two opposite effects: firstly a reduction of both N-EIIs and EIIs' demand and secondly an enhanced comparative advantage for nuclear. But it may be surprising to see that the demand response effect dominates. To see why, one shall note that the EU-ETS implies globally higher electricity prices that decrease overall demand. This holds for all countries, but especially for Germany. Note that demand reduction in Germany exists because the transmission system does not allow Germany to import French nuclear production in the same way in summer and winter. Contrarily, in France where nuclear plants are located, the summer electricity price is only 5.42 €/MWh (see Table 20 in Appendix I). This leads to a dramatic decrease of revenues of nuclear capacities. In addition, the much lower *global* summer demand contributes to make these units only partially more competitive. This reasoning would apply to all CO_2 free equipments with high capacity costs: the impact of higher prices may make them unable to recover these high fixed costs.

Interestingly, the effect is different in 20IDEFR case. Nuclear capacity surges in Germany before the EU-ETS and sees a further incremental increase with the inception of the EU-ETS (see Tables 12 and 13 in Appendix I). In France, nuclear investments are lower than they were in the 20IFR scenario, but the behavior of the global system is thus much more satisfactory in the following sense: the decrease of German industrial demand is the remarkable component of the lower electricity demand in the 20IFR scenario (compare Tables 12 and 13 with Tables 6 and 7). This effect partially disappears as soon as nuclear capacities are allowed in Germany. The EU-ETS still decreases German EIIs demand, but by far not to the same extent as in the 20IFR case. The outcome is then what is expected: the EU-ETS implies a higher demand for nuclear capacity whose availability is no longer submitted to the intricacies of the transmission system. Nuclear investments in Germany are indeed huge, going from 42.5 before EU-ETS to 46 GW after the EU-ETS (see Tables 12 and 13 in Appendix I). Such an increase is obviously unrealistic: it simply represents the disequilibrium of the generation system observed with our data.

As a consequence, the German demand for new French nuclear energy together with the poor use of that capacity during the summer because of transmission limitations observed in the 20IFR scenario disappear when Germany can invest in nuclear. The result is that, in the 20IDEFR case, French nuclear investments in the NETS_R and R scenarios decrease compared to the corresponding scenarios of the 20IFR case because of the loss of the German market.

However, the EU-ETS maintains French nuclear investments higher than before the regulation (compare case R and NETS_R in Tables 12 and 13). Needless to say the same analysis would apply for any carbon free technology with high investment costs. The implication of this analysis is thus straightforward: it is well known that the implementation of the EU-ETS is costly, but this cost is probably warranted because of climate change. The differentiated energy policies combined with transmission shortage makes the EU-ETS unnecessarily costly.

7.3 Remedies? The impact of the average cost contracts

EIIs reason with respect to the situation that they see or foresee in business as usual conditions. The EU-ETS increases the EIIs' electricity costs that they argue will induce them to relocate. They attribute this situation to different factors, namely the marginal cost pricing that results from the restructuring, the limitation of nuclear development that increases the generation cost and the restriction of transmission capacities that prevents them from procuring nuclear electricity where its development is allowed. EIIs consequently argue that average cost contracts should restore part of the competitiveness of electricity prices and hence seriously mitigate the impact of the EU-ETS. EIIs also argued against the granting of free allowances to generators. This issue is now settled by Directive 2009/29/EC that imposes full auctioning of allowances from 2013 on for the electricity sector. We assume full auctioning of allowances throughout the paper and therefore do not discuss that point.

One can first note that the previous discussion shows that nuclear development would allay most of EIIs' concerns. Taking the case 20IDEFR, one observes that the reduction of demand due to the EU-ETS is quite small and that a combination of French and German nuclear capacities with the EU-ETS is much more favorable to the EIIs than a situation without EU-ETS and nuclear investments limited to France (see Table 2).

7.3.1 The Regional Average Cost price

Consider first the impact of the regional average cost contract. Imposing a single price for EIIs throughout the CWE amounts to make nuclear capacity available to all EIIs of Central Western Europe at average cost, but only up to what the grid allows. This leads to a surge of German EIIs' demand together with a drop of the French one with respect to the corresponding reference ETS (R) case. Similarly, Belgium and the Netherlands benefit from this contract. This finding applies to both the 08FC and 20IFR cases. The contract is thus globally a remedy for the non nuclear countries, but it hurts the nuclear countries. This transfer of benefit, from those which invested in nuclear capacity to those which did not (or did less), has already been extensively pointed out in the French debate and is reflected in the "Loi NOME" (see Appendix B). This suggests that France will oppose the implementation of this system. It can do so by direct political intervention. From a technical point of view, it can also proceed by artificially limiting cross border trade, for instance by slowing down the evolution towards a more efficient arrangement of transmission.

It is also worthwhile noting that the regional average cost price is only a very partial remedy for the non nuclear countries. German demand only partially recovers from the inception of the EU-ETS in the 08FC case and none of the non-nuclear country fully recovers in the 20IFR case (see Table 3). Regional average cost contracts are thus beneficial, but only to some extent. The situation is similar in nature, but smaller in scope, when nuclear investments are permitted in both France and Germany. We had seen that the inception of the EU-ETS only induced a small impact on EIIs. Here again, the regional average cost contract only allows for a partial recovery. Also because France shares its capacities with neighboring countries and is only paid for them at average cost, it simply stops investing in new nuclear units in the 20IFR case (see Tables 8 and 9 in Appendix I) and nuclear investments are very limited in the 20IDEFR scenario (see Tables 14 and 15 in Appendix I). In short, the average cost contract does not fulfill all EIIs expectations; they also hamper a possible nuclear renaissance.

7.3.2 The Zonal Average Cost price

The situation is quite different in the zonal average cost pricing system. Comparing to the reference ETS (R) case of the 08FC scenario, the effect of the zonal average cost contract is again easy to grasp. Specifically, EIIs' demand in France jumps, while it slightly recovers in Germany, does very well in Belgium, but declines in the Netherlands (see Table 3). In other words, countries with nuclear capacities benefit, but these benefits are not sufficient to fully mitigate the impacts of the EU-ETS in the 08FC case. The situation is similar in the 20IFR scenario. French demand jumps and is now higher than before the inception of the EU-ETS. German and Belgian EIIs' demands partially recover because of the average cost, but not enough to recover pre EU-ETS levels. Dutch industrial demand declines. This should in principle induce Germany to support that system and hence to induce improvements in the organization of cross border trade. But strangely Germany has not really done so up to now.

The 20IDEFR case does not bring any surprise. EIIs' demand supplied by nuclear at average cost more than compensates the pre EU-ETS demand in Germany and France where nuclear (investment) is permitted. As expected zonal average cost plays some role, but does not fully compensate the impact of the EU-ETS when nuclear investments remain prohibited (Belgium and especially the Netherlands).

7.4 Other effects

7.4.1 N-EIIs

These arrangements obviously also have an impact on the other agents of the system. By construction, we assume a lower price elasticity for N-EIIs. The impact of the EU-ETS is thus smaller for them, but their demand still decreases with the inception of the EU-ETS (see Tables 2 and 18 in Appendix I). The average cost contracts aggravate this decreasing trend when capacities are fixed or when nuclear investments are limited to France. As for EIIs, allowing for German nuclear investments restores N-EIIs position whatever the price arrangement. Welfare analysis confirms this finding (see Tables 4 and 5).

7.4.2 Generators

It is now well recognized that the introduction of the EU-ETS can have unintended consequences on generators' profits. This is obviously the case for free allowances that are passed in the price of electricity (as expected in perfect competition) and enhance profits. We assume full auctioning of allowances in this paper with the results that the EU-ETS can increase or decrease generators' profits depending on the generation structure and transmission possibilities. We observe that the inception of the EU-ETS decreases generators profits globally (see Tables 4 and 5). As expected by the EIIs, the introduction of the average cost contracts further decreases the profit of generators. This may look like contradicting the classical theorem that claims that average costs should be equal to long run marginal costs in optimally adjusted system, and the implicit corollary that paying average total cost or long run marginal cost should not make a difference. This classical theorem does not apply here because the model does not satisfy its assumptions. In contrast with the classical theorem, this generation system has two "non-adaptable" resources, namely the grid and the total emission possibilities. Long run average and marginal costs are no longer equal when some resources cannot be adapted.

7.4.3 CO_2 price

Average cost pricing embeds the price of CO_2, which is therefore no longer priced at marginal cost to EIIs. This goes against the principle of the EU-ETS which requires that CO_2 is priced at marginal opportunity cost (even if allowances have been received free) in order to induce efficient reduction of CO_2. The result of violating this requirement is that average cost pricing increases emissions and the marginal cost of allowances (compare R with RAC and ZAC cases in Table 24 of Appendix I). This in turn increases the electricity price for N-EIIs.

8 Conclusion

The inception of the EU-ETS in the sole EU is obviously of concern for EIIs that need to compete on an international basis. It may become a global EU subject of concern if the EU-ETS further reduces the role of European industry in today world where some services are destined to decline and others are already developing in other regions. It is thus tempting to adapt the EU-ETS to mitigate some of its effects in order to retain industrial activities in Europe. We take up one of the proposals for doing so, namely the recourse to average cost pricing of electricity to EIIs. The principle is to replace the marginal cost pricing that is meant to derive from the restructuring of the power market by contracts that compute the full cost of electricity, transmissions and CO_2 and reallocate them to EIIs. We analyze the problem by modeling the impact of the inception of the EU-ETS under three different investment scenarios: fixed capacities in 2008, French nuclear investments in 2020 and German and French nuclear investments in 2020. As expected by EIIs, average cost pricing decreases the profits of the generators in a way that should reduce their electricity costs. Also expected, but from standard economic theory, average cost pricing decreases overall welfare compared to pure marginal cost pricing. Much less expected, EIIs remains far from compensated from the impact of the EU-ETS. Last but not least, except when energy investment policies are harmonized (in this exercise among France and Germany), average cost pricing favors EIIs of one country but hurts those of another with the result that it will always be impossible to agree upon any proposal in the European context. Harmonization of investment policies is the way forward, but it seems a long way off.

From a technical point of view, one shall note that the analysis was conducted using non-monotonic equilibrium models. These are still unusual, but the intricacies of emission policies have generated a recent, but strong interest for these models. These are still poorly understood and could probably be useful for tackling these complex situations where more or less ad hoc policies are introduced to mitigate the unintended consequences of other more or less ad hoc policies.

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A On the relation of our problem with carbon leakage

With "carbon leakage" one indicates the relocation of CO_2 emission and, consequently, of production activities from areas subject to carbon regulation to areas where such regulation is absent of more lenient. This phenomenon can arise when different carbon legislations are enforced in jurisdictions located in a single trading area. Our model is inspired by the situation currently faced by the European industrial consumers: Directives 2003/87/EC and 2009/29/EC introduce a cap and trade system for CO_2 emissions (the EU-ETS) that affects both the power and oil refining sectors as well as Energy Intensive Industries (EIIs). The situation is particularly dramatic for EIIs which face both direct and indirect EU-ETS costs. Direct ETS burdens come from the costs of abating emissions from old technologies and buying CO_2 allowances on the emission market. The pass through of carbon cost in electricity prices operated by generators corresponds to the indirect ETS charge. The combined action of these two carbon costs may negatively affects European industries' competitiveness on international markets and incentives the carbon leakage effect.

Firms affected by a hard carbon legislation and facing competitors operating under softer carbon restrictions threaten to relocate to more carbon accommodating regions, possibly increasing emissions. Carbon leakage may result from relocation of either generators (see Chen et al. [1]) or consumers (see Businesseurope [6], [7]). Chen et al. [1] deals with carbon leakage in California in the sole power sector; they consider different organisations of marginal cost based pricing that it treats with fixed capacities.

EU Directive 2009/29/EC recognizes the phenomenon of carbon leakage and the possible need for special measures. Various authors have also discussed the problem (e.g. Demailly and Quirion [2], [3], Droge and Cooper [4], Hourcade et al. [6], Meunier and Ponssard [8], Ponssard and Walker [9] and Reinaud [11], [12], [13]) and we refer the interested reader to these analyses.

B On long run average cost contracts in the EU restructured power system

The introduction of average cost base prices in some market segments, even though it appears like an important deviation with respect to the paradigm of competitive electricity markets, has made its way in Europe. The Finnish pulp and paper industry concluded such a contract with a consortium initially formed by Areva and Siemens (Siemens gave up and sold its share to Areva[12]) to build the fifth nuclear power plant in Olkiluoto on the Western coast of Finland[13]. This plant is now scheduled to come on line in 2013. Long term average cost based contracts also underly the Exeltium consortium in France where a number of EIIs (namely, Air Liquide, ArcelorMittal, Arkema, Rio-Tinto-Alcan, Rhodia and Solvay) have concluded long term contracts with EdF. After negotiations lasted almost three years, in 2008 EdF and Exeltium have finalized their partnership agreement following the initiative launched by the government in 2005. With this agreement that entered in force on 1st May 2010, 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 energy intensive industries, over a total of 24 years[14].

In both cases, long term competitiveness and price stability are invoked to justify these contracts. Exeltium is the case in point because European competition authorities declared this contract compatible with European competition law after adaptations on resale clauses. Last but definitely not least this duality of markets is now enshrined in the new French NOME law (see Projet Loi [10] for the law and motivation; see also Finon [5] and Lévêque and Saguan [7]

[12] See http://www.hs.fi/english/article/Siemens+to+give+up+nuclear+joint+venture+with+Areva/1135243067027

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[14] See EdF press release at
http://press.edf.com/fichiers/fckeditor/Commun/Developpement_Durable/Publications/Annee/2008/cp_20080731_va.pdf and http://nuclearstreet.com/nuclear_power_industry_news/b/nuclear_power_news/archive/2010/03/29/partnership-agreement-between-edf-and-exeltium-scheduled-to-start-on-1st-may-2010-03292.aspx

for critiques). Attempts to conclude special contracts sourced on base load plants were also observed in other countries but have so far not come to fruition. Differentiated national nuclear policies and the difficulty to trade electricity across borders are the key reasons for this failure. This justifies introducing transmission and national investment policies in models and analysis as attempted in this paper.

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C Description of a flow-based system

Power flows in the electricity grid according to Kirchhoff's laws. These can be represented in a particularly simple form through the so-called Power Transfer Distribution Factor ($PTDF$)

matrix. These factors are defined as follows. Consider an electricity network consisting of nodes and lines. Select a particular node in the grid identified as the "hub" where the energy market clears and the electricity price is determined. Consider now an injection x_i at some other node i of the grid with withdrawals at the hub. Because of Kirchhoff's laws, electricity flows through the different lines according to a well defined pattern that one can represent by coefficients referred to as $PTDFs$. By definition the $PTDF_{i,l}$ represents the fraction of the injection x_i at node i flowing through line l. Flows described in these terms have good algebraic properties: the flow through line l resulting from a combination of injection/withdrawal x_i at node i and a injection/withdrawal x_j at node j is the sum $PTDF_{i,l} \cdot x_i + PTDF_{j,l} \cdot x_j$. This makes it possible to represent the flows the grid through linear relations.

D Mixed Complementarity Formulation of the Perfect Competition Model

The complementarity formulation of the perfect competition model groups all agents' problems and balance constraints. The TSO's problem is summarized by condition (27) meaning that one of the dual variables $\mu^+_{l,t}$ and $\mu^-_{l,t}$ is positive when the flowgate l is congested in time segment t. Condition (28) restates constraint (2) and indicates that the scarcity rent $\nu_{f,i,k,t}$ is positive when the total available capacity $(X_{f,i,k} + x_{f,i,k})$ is fully utilized. Condition (29) summarizes the generator's optimal behaviour and expresses production efficiency: the electricity price $p_{i,t}$ recovers the fuel $(c_{f,i,k})$ and the emission opportunity $(e_k \cdot \lambda)$ costs as well as the marginal capacity value $(\nu_{f,i,k,t})$ whenever generation $(y_{f,i,k,t})$ is positive. Condition (30) corresponds to the first order condition of the investment variable $x_{f,i,k}$. This means that generators invest only if the unitary marginal value of new capacity $(\nu_{f,i,k,t})$ equals the investment costs $(I_{f,i,k})$. Concerning the demand side, considering that $P^2_{i,t}(d^2_{i,t}) = p_{i,t}$ and after replacing $P^2_{i,t}(d^2_{i,t})$ by its affine expression, we get condition (31). An identical reasoning applied to EIIs leads to condition (32). The clearing of the energy market implies an energy balance that is matched with the dual variable π_t that in the flowgate representation of the network corresponds to the energy balance at the hub node. The hub price π_t can be considered as a system price that after adding the transmission costs, $(-\mu^+_{l,t} + \mu^-_{l,t}) \cdot PTDF_{i,l}$, gives the zonal marginal electricity prices $p_{i,t}$ paid by consumers as indicated in conditions (31) and (32). Note that zonal electricity prices are equal to the hub price when there is no congestion. Finally, condition (34) is the complementarity form of constraint (9). It means that the allowance price λ is positive when the emission constraint is binding.

$$0 \leq Linecap_l \mp \sum_i PTDF_{i,l}(\sum_{f,k} y_{f,i,k,t} - d^1_i - d^2_{i,t}) \perp \mu^{\pm}_{l,t} \geq 0 \quad \forall\ l,t \tag{27}$$

$$0 \leq X_{f,i,k} + x_{f,i,k} - y_{f,i,k,t} \perp \nu_{f,i,k,t} \geq 0 \quad \forall\ f,i,k,t \tag{28}$$

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu_{f,i,k,t} - p_{i,t} \perp y_{f,i,k,t} \geq 0 \quad \forall\ f,i,k,t \tag{29}$$

$$0 \leq I_{f,i,k} - \sum_t \tau_t \cdot \nu_{f,i,k,t} \perp x_{f,i,k} \geq 0 \quad \forall\ f,i,k \tag{30}$$

$$p_{i,t} = a^2_{i,t} - b^2_{i,t} \cdot d^2_{i,t} \qquad \forall\ i,t \tag{31}$$

$$\sum_t \tau_t \cdot p_{i,t} = a_i^1 - b_i^1 \cdot d_i^1 \quad \forall\ i \tag{32}$$

$$p_{i,t} = \pi_t + \sum_l PTDF_{i,l}(-\mu_{l,t}^+ + \mu_{l,t}^-) \quad \forall\ i,t \tag{33}$$

$$0 \le E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y_{f,i,k,t} \perp \lambda \ge 0 \tag{34}$$

E Properties of the Perfect Competition Model

The reference model extends the standard capacity expansion model and the associated peak load pricing theory developed in the early days of electricity economics by including transmission and emission markets. It is a convex problem as stated in Proposition 1.

E.1 Existence of Equilibrium

Proposition 1 *The set of mixed complementarity conditions (27)-(34) plus the market balance (8) are the KKT conditions of a convex optimization problem. They have a convex solution set.*

Proof of Proposition 1: Consider the following maximization problem:

$$\textbf{Max} \quad \int_0^{d_i^1} P_i^1(\xi)d\xi + \sum_t \tau_t \left[\int_0^{d_{i,t}^2} P_{i,t}^2(\xi)d\xi - \sum_{f,i,k} c_{f,i,k} \cdot y_{f,i,k,t} \right] - \sum_{f,i,k} I_{f,i,k} \cdot x_{f,i,k}$$

s.t.

$$0 \le X_{f,i,k} + x_{f,i,k} - y_{f,i,k,t} \qquad (\tau_t \nu_{f,i,k,t}) \quad \forall\ f,i,k,t$$

$$\sum_{f,i,k} y_{f,i,k,t} - \sum_i d_i^1 - \sum_i d_{i,t}^2 = 0 \qquad (\tau_t \pi_t) \quad \forall\ t$$

$$-Linecap_l \le \sum_i PTDF_{i,l}(\sum_{f,k} y_{f,i,k,t} - d_i^1 - d_{i,t}^2) \le Linecap_l \qquad (\tau_t \mu_{l,t}^{\pm}) \quad \forall l,t$$

$$0 \le E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y_{f,i,k,t} \qquad (\lambda)$$

$$0 \le y_{f,i,k,t}, \quad x_{f,i,k}, \quad d_{i,t}^2, \quad d_i^1 \quad \forall\ f,i,k,t$$

The objective function is the difference between a concave function (the consumers' willingness to pay $\sum_t \tau_t \int_0^{d_{i,t}^2} P_{i,t}^2(\xi)d\xi$ and $\int_0^{d_i^1} P_i^1(\xi)d\xi$) and linear functions representing the generators' operating and investment costs ($\sum_t \tau_t \sum_{f,i,k} c_{f,i,k} \cdot y_{f,i,k,t}$ and $\sum_{f,i,k} I_{f,i,k} \cdot x_{f,i,k}$). All constraints are linear. This means that the problem is convex. The solution set is then also convex. The KKT conditions of a convex problem suffice to characterize its global optimal solutions. We derive these conditions taking into account the non-negativity of these variables and show that they reproduce the set of complementarity conditions.

- Derivative w.r.t. variable $y_{f,i,k,t}$:

$$0 \le c_{f,i,k} + e_k \cdot \lambda + \nu_{f,i,k,t} - p_{i,t} \perp y_{f,i,k,t} \ge 0 \quad \forall\ f,i,k,t$$

- Derivative w.r.t. variable $x_{f,i,k}$:

$$0 \leq I_{f,i,k} - \sum_t \tau_t \cdot \nu_{f,i,k,t} \perp x_{f,i,k} \geq 0 \quad \forall\, i,k$$

- Derivative w.r.t. variable $d^2_{i,t}$:

$$p_{i,t} = a^2_{i,t} - b^2_{i,t} \cdot d^2_{i,t} \qquad \forall\, i,t$$

- Derivative w.r.t. variable d^1_i:

$$\sum_t \tau_t \cdot p_{i,t} = a^1_i - b^1_i \cdot d^1_i \quad \forall\, i$$

where $p_{i,t}$ is defined as $\pi_t + \sum_l PTDF_{i,l}(-\mu^+_{l,t} + \mu^-_{l,t})$. In addition, we consider the complementarity conditions of the inequality constraints (generation, transmission capacity and emission constraints) and the clearing of the energy market:

$$0 \leq X_{f,i,k} + x_{f,i,k} - y_{f,i,k,t} \perp \nu_{f,i,k,t} \geq 0 \quad \forall\, f,i,k,t$$

$$0 \leq Linecap_l \mp \sum_i PTDF_{i,l}(\sum_{f,k} y_{f,i,k,t} - d^1_i - d^2_{i,t}) \perp \mu^{\pm}_{l,t} \geq 0 \quad \forall\, l,t$$

$$0 \leq E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y_{f,i,k,t} \perp \lambda \geq 0$$

$$\sum_{f,i,k} y_{f,i,k,t} - \sum_i d^1_i - \sum_i d^2_{i,t} = 0 \qquad \forall\, t$$

□

F Mixed Complementarity Formulation of the Regional Average Cost Pricing Model

The mixed complementarity formulation (35)-(50) of the average cost based pricing model is a modification of the mixed complementarity model presented in Appendix D.

The transmission condition (27) is obtained by replacing the variable $y_{f,i,k,t}$ by the sum of $y^1_{f,i,k}$ and $y^2_{f,i,k,t}$ to account for the segmentation of the market into EIIs and N-EIIs. Under this assumption, the complementarity formulation becomes (35). The optimal N-EIIs' market condition (36) is an adaptation of condition (29) and states that, in perfect competition, the N-EIIs' marginal electricity price $p^2_{i,t}$ equals the sum of the marginal production ($c_{f,i,k}$), emission ($e_k \cdot \lambda$) and capacity ($\nu^2_{f,i,k,t}$) costs when generation ($y^2_{f,i,k,t}$) is positive.

The optimality of the dispatch to the EIIs' segment is given in (37). When condition (37) is binding, generators supplies EIIs with a positive quantity of electricity $y^1_{f,i,k}$. This implies that the sum of the marginal production ($c_{f,i,k}$), emission ($e_k \cdot \lambda$) and capacity ($\nu^1_{f,i,k}$) costs equals the quantity ($\theta^1 + \sum_{t,l} \tau_t \cdot PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l)$) that is likely to be a marginal price. The variable θ^1 is the marginal electricity price that EIIs would pay at the hub if they were charged at marginal cost. Recall that θ^1 is the dual variable of the EIIs' energy balance constraint (15) and assumes a role analogous to that of π_t^2 in the N-EIIs' problem. Their equality is stated in Corollary 1 that is presented in the following. This equality guarantees that notwithstanding average cost pricing, production is efficient. Average cost pricing only affects allocative efficiency.

As already said, the EIIs' model embeds both an "accounting" and an "economic" electricity prices. The former is the average cost price p^1, which EIIs effectively pay to generators and the TSO. The second is the transfer price θ^1 that guarantees the efficiency of both the capacity allocation between the two consumer groups and the efficiency of electricity generation.

Market segmentation requires generators to allocate their existing and new capacity to these two consumer groups. We make this allocation efficient by equalizing the marginal values of the capacity dedicated to the two consumer groups. The interpretation of this condition is obvious: capacities are resources that generators need to allocate to the two markets after paying for fuels, network and CO_2 costs. Similarly investment takes place up to the point where the marginal value of the capacity is equal to the investment cost. The standard efficiency condition is to allocate a given resource so as to equalize its marginal profitability in both market segments. Similarly one shall invest if the marginal profitability is identical in both segments and equal to the investment cost. A measure of this marginal profitability is immediately available for both market segments in the model as we now discuss. Condition (38) is the global constraint on existing capacities. It imposes that the sum of capacities $X^2_{f,i,k}$ and $X^1_{f,i,k}$, respectively reserved for N-EIIs and EIIs does not exceed the existing capacity $X_{f,i,k}$. The variable $\nu_{f,i,k}$, pairing (38), is the global capacity scarcity rent. Conditions (39) and (40) set the marginal values of the capacities in the two market segments. They mean that the quantity of electricity produced by generators for N-EIIs and EIIs ($y^2_{f,i,k,t}$; $y^1_{f,i,k}$ respectively) cannot exceed the dedicated capacity ($X^2_{f,i,k}+x^2_{f,i,k}$; $X^1_{f,i,k}+x^1_{f,i,k}$). The scarcity rents ($\nu^2_{f,i,k,t}$; $\nu^1_{f,i,k}$) paired with this condition are positive only when power plant (f,i,k) is at capacity. Conditions (41) and (42) equalize $\nu_{f,i,k}$ to $\nu^1_{f,i,k}$ and to the weighted sum of $\nu^2_{f,i,k,t}$. This guarantees production efficiency by forcing the equality of the marginal values of capacity of the consumer segments, irrespectively of the fact that the different electricity pricing schemes distort allocative efficiency. A similar reasoning holds also for conditions (43) and (44) that refer to the investments in new capacity for N-EIIs and EIIs respectively. The following lemma can be stated:

Lemma 1 *Assume the regional average cost model has an equilibrium. The EIIs' scarcity rent $\nu^1_{f,i,k}$ equals the time weighted sum of the N-EIIs' scarcity rent $\nu^2_{f,i,k,t}$.*

Proof of Lemma 1: This equality directly derives from (41) and (42). □

Taking stock of the results of Lemma 1, the electricity generation efficiency implied by the marginal price θ^1 is proved by the following corollary:

Corollary 1 *Assume the regional average cost model has an equilibrium. The allocation of capacities between EIIs and N-EIIs is production efficient at equilibrium. Generation is also efficient in the sense that θ^1 and the time weighted average of π_t^2 are equal.*

Proof of Corollary 1: The marginal electricity prices θ^1 and π_t^2 respectively match the EIIs' and the N-EIIs' energy balance constraints (45) and (46). Constraint (37) shows that θ^1, increased by the transmission cost ($\sum_{t,l}\tau_t \cdot PTDF_{i,l}(-\mu_l^{t,+}+\mu_l^{t,-})$), equals the fuel cost (parameter $c_{f,j,k}$), the allowance cost (variable $e_k \cdot \lambda$) and the capacity cost (variable $\nu^1_{f,i,k}$).

Constraint (36) shows that the N-EIIs' zonal marginal electricity price $p^2_{i,t}$ equals the sum of the fuel cost (parameter $c_{f,i,k}$), the allowance cost (variable $e_k \cdot \lambda$) and the capacity cost (variable $\nu^2_{f,i,k,t}$). Note that thanks to constraints (41) and (42), variables $\nu^1_{f,i,k}$ and $\nu^2_{f,i,k,t}$ (weighted by hours) are equal (see Lemma 1). This implies that $\theta^1 + \sum_{t,l} \tau_t \cdot PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l)$ equals $p^2_{i,t}$. Since $p^2_{i,t}$ results from the sum of π^2_t and the transmission costs $\sum_l PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l)$ (see (48)), this implies that θ^1 is equal to the time average sum of π^2_t. □

EIIs' demand is represented by condition (49) where p^1 is the regional average cost based price as defined in (19) whose equation is not reported here. Finally, (50) is the complementarity form of the emission constraint.

$$0 \leq Linecap_l \mp \sum_i PTDF_{i,l}(\sum_{f,k} y^1_{f,i,k} + \sum_{f,k} y^2_{f,i,k,t} - d^1_i - d^2_{i,t}) \perp \mu^{\pm}_{l,t} \geq 0 \quad \forall\, l,t \tag{35}$$

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu^2_{f,i,k,t} - p^2_{i,t} \perp y^2_{f,i,k,t} \geq 0 \quad \forall\, f,i,k,t \tag{36}$$

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu^1_{f,i,k} - \theta^1 - (\sum_{t,l} \tau_t \cdot PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l)) \perp y^1_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{37}$$

$$0 \leq X_{f,i,k} - X^1_{f,i,k} - X^2_{f,i,k} \perp \nu_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{38}$$

$$0 \leq X^2_{f,i,k} + x^2_{f,i,k} - y^2_{f,i,k,t} \perp \nu^2_{f,i,k,t} \geq 0 \quad \forall\, f,i,t,k \tag{39}$$

$$0 \leq X^1_{f,i,k} + x^1_{f,i,k} - y^1_{f,i,k} \perp \nu^1_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{40}$$

$$0 \leq \nu_{f,i,k} - \sum_t \tau_t \cdot \nu^2_{f,i,k,t} \perp X^2_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{41}$$

$$0 \leq \nu_{f,i,k} - \nu^1_{f,i,k} \perp X^1_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{42}$$

$$0 \leq I_{f,i,k} - \sum_t \tau_t \cdot \nu^2_{f,i,k,t} \perp x^2_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{43}$$

$$0 \leq I_{f,i,k} - \nu^1_{f,i,k} \perp x^1_{f,i,k} \geq 0 \quad \forall\, f,i,k \tag{44}$$

$$\sum_{f,i,k} y^2_{f,i,k,t} - \sum_i d^2_{i,t} = 0 \quad (\pi^2_t) \quad \forall\, t \tag{45}$$

$$\sum_{f,i} y^1_{f,i} - \sum_i d^1_i = 0 \quad (\theta^1) \tag{46}$$

$$p^2_{i,t} = \pi^2_t + \sum_l PTDF_{i,l}(-\mu^{t,+}_l + \mu^{t,-}_l) \quad \forall\, i,l \tag{47}$$

$$p^2_{i,t} = a^2_{i,t} - b^2_{i,t} \cdot d^2_{i,t} \tag{48}$$

$$p^1 = a^1_i - b^1_i \cdot d^1_i \tag{49}$$

$$0 \leq E - (\sum_{f,i,k} e_k \cdot y^1_{f,i,k} + \sum_{t,f,i,k} \tau_t \cdot e_k \cdot y^2_{f,i,k,t}) \perp \lambda \geq 0 \tag{50}$$

G Mixed Complementarity Conditions of the Zonal Average Cost Model

We only report the complementarity conditions that are specific to the zonal average cost based model. We refer to Appendix F for the emission constraint (50), the endogenous allocation of existing and new capacity to N-EIIs and EIIs (38)-(44), the generators maximization problems (36), the N-EIIs' energy balance constraint (45) and the N-EIIs' price equations (47) and (48).

The new complementarity conditions of the transmission constraints are expressed in (51) and only account for the N-EIIs' sector; condition (52) replaces (37) of Appendix F as well as (53) substitutes (46) and finally (54) defines EIIs' electricity demand where p_i^1 is computed as in (25) in Section 4.3.

$$0 \leq Linecap_l \mp \sum_i PTDF_{i,l} \cdot (\sum_{f,k} y^2_{f,i,k,t} - d^2_{i,t}) \perp \mu^{\pm}_{l,t} \geq 0 \quad \forall\, l, t \tag{51}$$

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu^1_{f,i,k} - \theta^1_i \perp y^1_{f,i,k} \geq 0 \quad \forall\, f, i, k \tag{52}$$

$$\sum_f y^1_{f,i} - d^1_i = 0 \;\; (\theta^1_i) \qquad \forall\, i \tag{53}$$

$$p^1_i = a^1_i - b^1_i \cdot d^1_i \tag{54}$$

The results of Lemma 1 presented in Appendix F also hold for this average cost based model. Even though the reasoning is identical, Corollary 1 is substituted by the following:

Corollary 2 *Assume the zonal average cost model has an equilibrium. The allocation of capacities between EIIs and N-EIIs is production efficient at equilibrium. Generation is also efficient in the sense that θ^1_i and the time weighted average of $p^2_{i,t}$ are equal in each zone i.*

Proof of Corollary 2: The reasoning of this proof is as in Corollary 1, after comparing (52) and (36), taking into account (45) and (53). Due the EIIs' zonal electricity balance, θ^1_i in condition (52) is equal to the time weighted sum of $p^2_{i,t}$ in condition (36). □

H Properties of the Average Cost Pricing Models

The above models involve average cost prices and hence, differently from the reference problem, they can no longer be formulated as a global welfare maximization problem.

H.1 Existence and uniqueness properties

The relations (17), (18), (19) and (25), equating prices to average costs respectively in the regional and the zonal average cost models, introduce non convexities. This also may jeopardize the existence and the convexity of the solution set. In order to see this, consider a trivial, one plant and one consumer segment equilibrium model with existing capacity (no endogenous capacity). Figure 2 illustrates the situation. The average cost price is depicted by an hyperbola $p(q) = \frac{K}{Q} + C$ where K is the fixed cost of the existing capacity and C its proportional cost. The downward sloping linear curve represents the demand function. Non-convexity induced by the average cost price may lead to either no solution (the hyperbola lies above the demand curve) or to two (multiplicity of) disconnected solutions (the hyperbola crosses the demand curve in two points). The situation considered in this paper is much more complex: it contains existing capacities, new capacities and congestion costs whether due to the emission market or to transmission. The average cost function has thus the usual U shape curve (the downward part of the "U" shape being due to the fixed cost of the existing capacities and the upward part to the congestions caused by the limitations of transmission and CO_2 emissions). It is immediate to see that the same conclusion applies: one can have two or no intersection with the demand function.

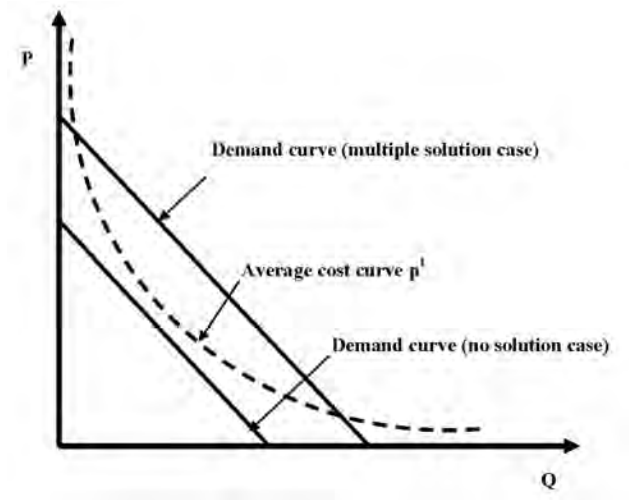

Figure 2: Average Cost Price Curve p^1

Models involving average cost pricing cannot be written as welfare optimization (they do not guarantee allocation efficiency). They can still be written as sequence of optimization problems (see Paul et al. [19] for the Haiku model and [1]). As in this paper, they can be written in complementarity form.

References

[1] Greenberg, H.J., F.H. Murphy. 1985. Computing Market Equilibria with Price Regulations Using Mathematical Programming. *Operations Research.* **33** 935-954.

H.2 Computing average supply costs

While the overall model is non convex, it contains a useful convex sub-model. Consider the regional average cost based model and take the relations obtained from the overall model by dropping the definition of the average cost prices and the demand system of the EIIs, namely conditions (17), (18), (19) and (20). We first state the following proposition. Note that a similar reasoning could be applied to the zonal average cost based model. Taking the demand of the

EIIs as fixed and leaving the demand of the N-EIIs responsive to price, we obtain a sub-model that we refer to as the *partial average cost model.*

Proposition 2 *The partial average cost model is formed by the KKT conditions of a convex optimization problem. It has a convex set of solutions.*

Proof of Proposition 2: The optimization problem we are looking for is as follows:

$$\textbf{Max} \quad \sum_t \tau_t \left[\int_0^{d^2_{i,t}} P^2_{i,t}(\xi) d\xi - \sum_{i,k} c_{f,i,k} \cdot y^2_{f,i,k,t} \right] - \sum_{f,i,k} c_{f,i,k} \cdot y^1_{f,i,k} - \sum_{f,i,k} I_{f,i,k} \cdot (x^2_{f,i,k} + x^1_{f,i,k})$$

s.t.

$$0 \leq X_{f,i,k} - X^2_{f,i,k} - X^1_{f,i,k} \qquad (\nu_{f,i,k}) \quad \forall\, f,i,k$$

$$0 \leq X^2_{f,i,k} + x^2_{f,i,k} - y^2_{f,i,k,t} \qquad (\tau_t \nu^2_{f,i,k,t}) \quad \forall\, f,i,k,t$$

$$0 \leq X^1_{f,i,k} + x^1_{f,i,k} - y^1_{f,i,k} \qquad (\nu^1_{f,i,k}) \quad \forall\, f,i,k$$

$$\sum_{f,i,k} y^2_{f,i,k,t} - \sum_i d^2_{i,t} = 0 \qquad (\tau_t \pi^2_t) \quad \forall\, t$$

$$\sum_{f,i,k} y^1_{f,i,k} - \sum_i d^1_i = 0 \qquad (\theta^1) \quad \forall\, t$$

$$-Linecap_l \leq \sum_i PTDF_{i,l} (\sum_{f,k} y^2_{f,i,k,t} - y^1_{f,i,k} - d^2_{i,t} - d^1_i) \leq Linecap_l \qquad (\tau_t \mu^{\pm}_{l,t}) \quad \forall\, l,t$$

$$0 \leq E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y^2_{f,i,k,t} - \sum_{f,i,k} e_k \cdot y^1_{f,i,k} \qquad (\lambda)$$

$$0 \leq y^2_{f,i,k,t}, \quad x^2_{f,i,k}, \quad X^2_{f,i,k}, \quad d^2_{i,t} \quad \forall\, f,i,k,t$$

$$0 \leq y^1_{f,i,k}, \quad x^1_{f,i,k}, \quad X^1_{f,i,k} \quad \forall\, f,i,k$$

where d^1_i is now a parameter.

The objective function is the difference between a concave function (the N-EIIs' willingness to pay $\sum_t \tau_t \int_0^{d^2_{i,t}} P^2_{i,t}(\xi)d\xi)$), and the sum of linear functions representing the generators' operating cost ($\sum_{t,f,i,k} \tau_t \cdot c_{f,i,k} \cdot y^2_{f,i,k,t}$ and $\sum_{f,i,k} c_{f,i,k} \cdot y^1_{f,i,k}$) and the investments cost ($\sum_{f,i,k} I_{f,i,k} \cdot (x^2_{f,i,k} + x^1_{f,i,k})$). Again, all constraints are linear. If we consider this model in minimization form, this implies that the problem is convex and hence also its solution set. Thanks to convexity, the KKT conditions are necessary and sufficient to characterize a global optimal solution. They are indicated in the following, noting that variables are non-negative:

- Derivative w.r.t. variable $y^2_{f,i,k,t}$:

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu^2_{f,i,k,t} - p^2_{i,t} \perp y^2_{f,i,k,t} \geq 0 \quad \forall\, f,i,k,t$$

- Derivative w.r.t. variable $y^1_{f,i,k}$:

$$0 \leq c_{f,i,k} + e_k \cdot \lambda + \nu^1_{f,i,k} - \theta^1 - \sum_t \tau_t \cdot \sum_l PTDF_{i,l}(-\mu^+_{l,t} + \mu^-_{l,t}) \perp y^1_{f,i,k} \geq 0 \quad \forall\, f,i,k$$

- Derivative w.r.t. variable $x^2_{f,i,k}$:

$$0 \le I_{f,i,k} - \sum_t \tau_t \cdot \nu^2_{f,i,k,t} \perp x^2_{f,i,k} \ge 0 \quad \forall\ i,k$$

- Derivative w.r.t. variable $x^1_{f,i,k}$:

$$0 \le I_{f,i,k} - \nu^1_{f,i,k} \perp x^1_{f,i,k} \ge 0 \quad \forall\ i,k$$

- Derivative w.r.t. variable $X^2_{f,i,k}$:

$$0 \le \nu_{f,i,k} - \sum_t \tau_t \nu^2_{f,i,k,t} \perp X^2_{f,i,k} \ge 0 \quad \forall\ f,i,k$$

- Derivative w.r.t. variable $X^1_{f,i,k}$:

$$0 \le \nu_{f,i,k} - \nu^1_{f,i,k} \perp X^1_{f,i,k} \ge 0 \quad \forall\ f,i,k$$

- Derivative w.r.t. variable $d^2_{i,t}$:

$$p^2_{i,t} = a^2_{i,t} - b^2_{i,t} \cdot d^2_{i,t} \qquad \forall\ t,i$$

where $p^2_{i,t}$ is defined as $\pi^2_t + \sum_l PTDF_{i,l}(-\mu^+_{l,t} + \mu^-_{l,t})$. Like in proof of Proposition 1, we consider the complementarity conditions of the inequality constraints (generation and transmission capacity and emission constraints) and the equality constraints defining the energy balance of the two markets:

$$0 \le X_{f,i,k} - X^2_{f,i,k} - X^1_{f,i,k} \perp \nu_{f,i,k} \ge 0 \quad \forall\ f,i,k$$

$$0 \le X^2_{f,i,k} + x^2_{f,i,k} - y^2_{f,i,k,t} \perp \nu^2_{f,i,k,t} \ge 0 \quad \forall\ f,i,k,t$$

$$0 \le X^1_{f,i,k} + x^1_{f,i,k} - y^1_{f,i,k} \perp \nu^1_{f,i,k} \ge 0 \quad \forall\ f,i,k$$

$$0 \le Linecap_l \mp \sum_i PTDF_{i,l}(\sum_{f,k} y^2_{f,i,k,t} - y^1_{f,i,k} - d^2_{i,t} - d^1_i) \perp \mu^{\pm}_{l,t} \ge 0 \quad \forall\ l,t$$

$$0 \le E - \sum_{f,i,k,t} \tau_t \cdot e_k \cdot y^2_{f,i,k,t} - \sum_{f,i,k} e_k \cdot y^1_{f,i,k} \perp \lambda \ge 0$$

$$\sum_{f,i,k} y^2_{f,i,k,t} - \sum_i d^2_{i,t} = 0 \quad (p^2_{i,t}) \quad \forall\ t$$

$$\sum_{f,i,k} y^1_{f,i,k} - \sum_i d^1_i = 0 \quad (\theta^1) \quad \forall\ t$$

□

H.3 Existence of an equilibrium

Because the average cost model implies non convexities, one cannot hope to call upon monotonic properties of the underlying complementarity formulation in order to prove the existence of an equilibrium. We therefore resort to standard fixed points arguments. The following is a sketch of a proof of existence and of the conditions for such an existence.

First assume that the solution of the *partial average cost model* is unique. This is easily guaranteed by making the short term cost functions of the generators strictly convex. This implies that the solution of the *partial average cost model* is a continuous mapping of the vector of EIIs' demands. Because total production and transmission costs are computed on the basis of this solution using algebraic operations, the *partial average cost model* also defines a continuous mapping from EIIs' demand into EIIs induced production and transmission costs and hence into the average cost price charged to EIIs.

Fixed point arguments required compact sets. We therefore also slightly modify the definition of the average cost price by capping it at some high level: if the average cost defined by the *partial average cost model* is higher than the cap, then the price is set to the cap (see Figure 3). While the average cost curve in Figure 2 represents the price p^1 as the true average cost price, $p^{1'}$ depicted in Figure 3 is the new (capped) average cost price that is guaranteed to remain in a compact set.

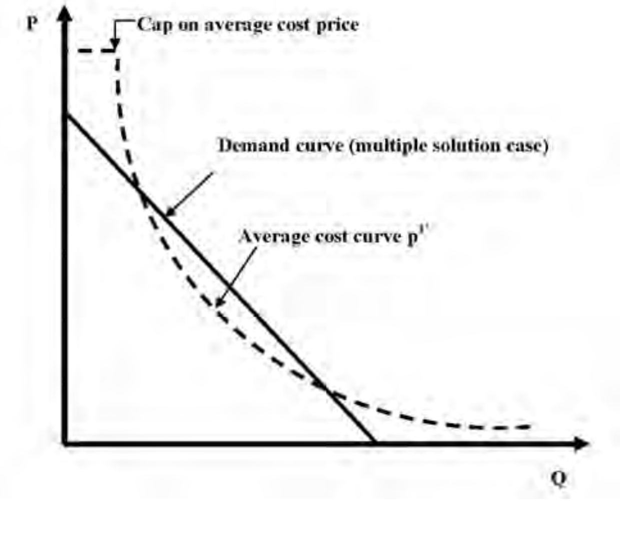

Figure 3: Capped Average Cost Price Curve $p^{1'}$

In order to invoke a fixed point argument, it suffices to combine the mapping from EIIs demand to the modified (capped) EIIs average cost price so defined with the EIIs demand system (from EIIs price to EIIs demand) in order to obtain a continuous mapping from the compact set of EIIs demand into itself. By Brower's theorem this mapping has a fixed point. The argument is summarized in the following proposition.

Proposition 3 *The modified (capped) average cost model has an equilibrium.*

Proof of Proposition 3: Consider the set $\prod_i [0, a_i^1/b_i^1]$ of feasible demand vectors of EIIs. As just discussed, the solution of the partial average cost model is a continuous mapping of the vector of EIIs' demands into the production and transmission costs incurred by EIIs. The combination of the capped average cost price, defined above, and of the demand relation (20) constitutes a mapping from the production and transmission costs of EIIs into the set of EIIs' demand vectors. The combination of these two mappings is a continuous mapping from the set of feasible EIIs' demand vectors into itself. On the basis of these observations, the proof is a direct application of Brower's fixed point theorem with a continuous mapping from $\prod_i [0, a_i^1/b_i^1]$ into itself. $\square$

It remains to explain the role of the modification of the pricing mapping. As can be seen from Figure 2, an average cost pricing model can be infeasible (and hence have no equilibrium) when the average cost price is too high for the demand. In practice, this means that the demand vanishes (since there is no feasible demand) and that the generator is left with stranded assets (assets for which it cannot recover the cost). This is exactly what the modified average pricing scheme represents. In other words, fixed costs should not be too high in order for the average cost model to have an equilibrium. Unfortunately there is no practical way to identify ex ante the values of fixed (capacity) charges for which the equilibrium ceases to exist.

H.4 Numerical Considerations

The two average cost models are non-convex and hence typically more difficult to solve than convex problems. Particular difficulties arise here because of the possibility that there is no positive solution for some zonal EIIs. This is so when capacity charges contribute too much to the average cost price, an occurrence that we cannot identify with certainty in a non-convex equilibrium model. We try to mitigate these numerical difficulties by solving the average cost based models as a sequence of two different sub-problems. We first solve a preliminary model by simulating a perfectly competitive power market where EIIs and N-EIIs are supplied by dedicated capacities, but both buy electricity at the marginal cost price. This preliminary problem is convex and has always a solution that is used as starting point for solving the average cost pricing problem. This procedure is applied to the two average cost pricing models. These non-convex models may have either no or multiple positive solutions. The empirical results of our simulations (see Section 7) show that all models have positive solutions, even though possibly multiple. These disjoint solutions are detected by changing the starting point of the algorithm. Different starting points can lead to different capacity allocation between EIIs and N-EIIs. Notwithstanding these problems, the results are stable in the sense that perturbations of the model lead to globally similar policy effects. For instance and of particular relevance, modifying the assumption of EIIs' price elasticity smoothly changes the total capacity allocated to EIIs (this capacity determines the electricity price to EIIs).

Another important observation is that the regional average cost pricing model is more complex than the zonal average cost problem. Specifically, the regional average cost price model involves the sum of the average production (variables and capacity) costs of the dedicated units and the average transmission charges paid by EIIs for their use of the congested transmission grid. Production costs include only primal variables. The computation of the transmission cost involves the product of primal (injection and withdrawals in $\sum_{f,k} y_{f,i,k}^1 - d_i^1$), and dual variables

($\mu_l^{t,+}$, $\mu_l^{t,-}$), corresponding to the marginal congestion costs (see equation (18)). The absence of the average transmission charges should simplify the zonal average cost problem. Surprisingly, we did not notice any difference in the solution of the two types of problems.

I Additional results

MW	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle	Total
Nuclear		2,176						**2,176**
Lignite	14,014							**14,014**
Coal			3,599		4,693	512		**8,804**
CCGT		11,246		676	81		5,829	**17,832**
Total	**14,014**	**13,422**	**3,599**	**676**	**4,774**	**512**	**5,829**	**42,827**

Table 6: Investments in the NETS_R case of the 20IFR scenario

MW	Germany	France	Krimpen	Total
Wind	17,433			**17,433**
Nuclear		1,370		**1,370**
CCGT		8,700	2,953	**11,653**
Total	**17,433**	**10,070**	**2,953**	**30,456**

Table 7: Investments in the R case of the 20IFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Wind	6,020					**6,020**
CCGT		5,649	592	2,588	68	**8,898**
Total	**6,020**	**5,649**	**592**	**2,588**	**68**	**14,918**

Table 8: Investments for N-EIIs in the RAC case of the 20IFR scenario

MW	Germany	Merchtem	Krimpen	Total
Wind	22,254			**22,254**
CCGT		778	1,888	**2,666**
Total	**22,254**	**778**	**1,888**	**24,920**

Table 9: Investments for EIIs in the RAC case of the 20IFR scenario

MW	Germany	France	Merchtem	Krimpen	Total
Wind	4,071				**4,071**
Nuclear		2,028			**2,028**
CCGT		8,865	345	1,678	**10,887**
Total	**4,071**	**10,892**	**345**	**1,678**	**16,985**

Table 10: Investments for N-EIIs in the ZAC case of the 20IFR scenario

MW	Germany	France	Merchtem	Krimpen	Total
Wind	18,820				**18,820**
Nuclear		2,575			**2,575**
CCGT			644	1,052	**1,695**
Total	**18,820**	**2,575**	**644**	**1,052**	**23,091**

Table 11: Investments for EIIs in the ZAC case of the 20IFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Nuclear	42,395	673				**43,067**
Coal			3,327	2,930	886	**7,143**
CCGT		12,933			555	**13,487**
Total	**42,395**	**13,606**	**3,327**	**2,930**	**1,441**	**63,697**

Table 12: Investments in the NETS_R case of the 20IDEFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Nuclear	45,894	908				**46,802**
Coal			231			**231**
CCGT		11,421	1,718	427	1,981	**15,547**
Total	**45,894**	**12,329**	**1,949**	**427**	**1,981**	**62,581**

Table 13: Investments in the R case of the 20DEIFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Nuclear	5,510					**5,510**
CCGT		11,057	1,887	1,084	1,593	**15,621**
Total	**5,510**	**11,057**	**1,887**	**1,084**	**1,593**	**21,131**

Table 14: Investments for N-EIIs in the RAC case of the 20IDEFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Nuclear	38,943	1,346				**40,290**
CCGT			2,047	816	892	**3,756**
Total	**38,943**	**1,346**	**2,047**	**816**	**892**	**44,045**

Table 15: Investments for EIIs in the RAC case of the 20IDEFR scenario

MW	Germany	France	Merchtem	Krimpen	Maastricht	Total
Nuclear	6,052	1,400				**7,452**
CCGT		11,234	1,165	216	1,503	**14,118**
Total	**6,052**	**12,635**	**1,165**	**216**	**1,503**	**21,571**

Table 16: Investments for N-EIIs in the ZAC case of the 20IDEFR scenario

MW	Germany	France	Merchtem	Maastricht	Total
Nuclear	40,158	2,152			**42,310**
CCGT			1,283	430	**1,713**
Total	**40,158**	**2,152**	**1,283**	**430**	**44,023**

Table 17: Investments for EIIs in the ZAC case of the 20IDEFR scenario

08FC								
N-EIIs	**Summer**				**Winter**			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	20,707	19,329	18,285	18,552	46,208	47,240	45,950	46,369
France	24,401	24,401	24,401	24,401	51,959	51,874	51,669	48,763
Belgium	3,270	3,153	3,077	3,096	7,477	7,546	7,435	7,011
Netherlands	5,119	4,940	4,786	4,827	11,758	11,914	11,692	11,576
Total	**53,498**	**51,823**	**50,549**	**50,877**	**117,402**	**118,574**	**116,746**	**113,718**
20IFR								
	Summer				**Winter**			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	23,191	21,633	21,522	21,602	54,031	53,203	53,599	53,315
France	26,700	27,286	27,330	27,297	60,625	58,534	58,395	58,495
Belgium	3,725	3,529	3,520	3,525	8,756	8,475	8,420	8,438
Netherlands	5,828	5,531	5,522	5,534	13,866	13,436	13,393	13,415
Total	**59,444**	**57,979**	**57,893**	**57,957**	**137,277**	**133,649**	**133,806**	**133,663**
20IFR								
	Summer				**Winter**			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	23,290	23,055	23,486	23,114	55,891	56,729	55,192	56,519
France	26,700	26,943	27,162	26,973	60,625	59,759	58,976	59,652
Belgium	3,705	3,590	3,511	3,573	8,805	8,620	8,506	8,604
Netherlands	5,823	5,658	5,603	5,665	13,917	13,728	13,533	13,701
Total	**59,518**	**59,246**	**59,761**	**59,325**	**139,239**	**138,836**	**136,207**	**138,476**

Table 18: NEIIs' hourly electricity demand in the different scenarios

€/MWH	Summer				Winter			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	39.24	87.87	124.71	115.28	122.76	78.83	126.38	120.51
France	4.18	4.18	4.18	4.18	122.76	123.82	126.38	162.58
Merchtem	67.88	90.92	107.33	103.13	122.76	116.57	126.38	168.41
Gramme	30.35	61.65	78.83	74.98	122.76	117.30	126.38	150.70
Krimpen	61.41	85.57	106.06	100.56	122.76	114.55	126.38	137.50
Maastricht	61.41	82.00	102.30	96.63	122.76	114.31	126.38	119.95
Zwolle	55.06	84.45	109.10	102.54	122.76	112.87	126.38	127.55

Table 19: Marginal cost prices for EIIs (NETS_R; R) and N-EIIs (NETS_R; R, RAC, ZAC) in the different case of the 08FC scenario

€/MWH	Summer				Winter			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	39.24	88.35	91.83	89.33	94.28	104.62	99.68	103.23
France	21.83	5.42	4.18	5.11	95.72	118.98	120.53	119.42
Merchtem	49.94	91.13	92.69	91.57	92.39	115.44	119.93	118.82
Gramme	31.58	62.66	65.39	64.65	95.12	113.67	117.37	115.41
Krimpen	48.65	85.72	86.88	85.48	88.65	110.41	112.52	111.81
Maastricht	49.67	82.04	82.53	81.13	87.21	108.09	113.46	108.95
Zwolle	46.26	84.66	86.22	84.54	88.65	108.19	108.36	108.27

Table 20: Marginal cost prices for EIIs (NETS_R; R) and N-EIIs (NETS_R; R, RAC, ZAC) in the different case of the 20IFR scenario

€/MWh	Summer				Winter			
	NETS_R	**R**	**RAC**	**ZAC**	**NETS_R**	**R**	**RAC**	**ZAC**
Germany	36.13	43.53	29.96	41.67	71.01	60.53	79.75	63.16
France	21.83	15.03	8.89	14.19	95.72	105.36	114.06	106.55
Merchtem	52.21	77.52	86.22	78.71	89.17	104.76	113.46	105.95
Gramme	39.24	54.74	86.22	63.16	89.88	101.29	110.39	102.53
Krimpen	50.02	71.05	79.75	72.24	86.71	98.29	106.99	99.48
Maastricht	48.65	71.05	79.75	63.48	88.65	98.29	106.99	99.48
Zwolle	45.57	63.20	63.75	60.79	82.12	84.96	97.43	86.67

Table 21: Marginal cost prices for EIIs (NETS_R; R) and N-EIIs (NETS_R; R, RAC, ZAC) in the different case of the 20IDEFR scenario

€/MWh	08FC	20IFR	20IDEFR
RAC	86.70	76.31	57.93

Table 22: RAC prices in the different scenarios

€/MWh	ZAC		
	08FC	**20IFR**	**20IDEFR**
Germany	95.16	86.30	50.84
France	53.95	52.37	52.25
Merchtem	85.19	87.49	83.63
Gramme	71.32	71.15	71.73
Krimpen	99.32	96.12	85.68
Maastricht	107.22	96.86	84.87
Zwolle	107.93	99.26	91.71

Table 23: ZAC prices in the different scenarios

€/ton	FC	20IFR	20IDEFR
NETS_R			
R	53.34	53.83	22.31
RAC	91.32	57.43	42.45
ZAC	81.59	54.84	25.06

Table 24: CO_2 prices in the different scenarios

J Reference data

MWh	EIIS		N-EIIs	
	Summer	**Winter**	**Summer**	**Winter**
Germany	31,299	31,299	19,835	49,975
France	20,125	20,125	22,304	56,195
Merchtem	3,550	3,550	2,246	5,660
Gramme	1,521	1,521	963	2,426
Krimpen	3,466	3,466	3,179	8,011
Maastricht	770	770	707	1,780
Zwolle	1,265	1,265	1,161	2,925

Table 25: EIIs and N-EIIs' hourly reference demand by zone and time horizon used in the 2008 scenario

MW	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	929	6,461		15	4	4	4
Wind	4,540	647	42	28	220	48	220
Nuclear	15,358	48,078	2,148	2,279	388		
Lignite	17,327						
Coal	22,164	6,320	900	564	2,704	0	416
CCGT	12,220	9,239	2,805	1,309	3,939	2,593	4,297
Oil		4,793	55	194			

Table 26: Existing capacity by zone and technology type in the 2008 scenario

€/MWh	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Windo	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear	4.18	4.18	4.18	4.18	4.18	4.18	4.18
Lignite	36.13	36.13	36.13	36.13	36.13	36.13	36.13
Coal	39.24	39.24	39.24	39.24	39.24	39.24	39.24
CCGT	85.26	68.48	67.88	67.88	61.41	61.41	61.41
Oil	99.54	99.54	99.54	99.54	99.54	99.54	99.54

Table 27: Marginal production costs by zone and technology type

€/MWh	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	36.98	36.98	36.98	36.98	36.98	36.98	36.98
Wind	95.08	95.08	106.71	106.71	106.71	106.71	106.71
Nuclear	46.38	48.22	66.59	66.59	58.97	58.97	58.97
Lignite	25.88	28.26	28.26	28.26	25.96	25.96	25.96
Coal	25.88	28.26	28.26	28.26	25.96	25.96	25.96
CCGT	11.27	11.27	11.27	11.27	11.27	11.27	11.27
Oil	11.27	11.27	11.27	11.27	11.27	11.27	11.27

Table 28: Hourly fixed costs by zone and technology type