Effects of an Internal Electricity Market in Europe:

Results from a Simulation Model of the European Power Systems

Frank Hoster*

Institute of Energy Economics

University of Cologne

Albertus Magnus Platz

50923 Köln

Germany

*Dr. Frank Hoster, Energiewirtschaftliches Institut an der Universität Köln, Albertus Magnus Platz, 50923 Köln, Tel: ++49-221-412022, Fax: ++49-221-446537, E-mail: hoster@wiso.uni-koeln.de

Abstract

The European common market for electricity and the opening of the power markets to Eastern Europe and Scandinavia will have a drastic and lasting effect on the structure of the European electricity industry. For this reason the introduction of an internal market is accompanied by a continuing and sometimes heated debate over the possible consequences concerning the volume of power trade within Europe and the future generation structure. In any case in the near future, the integrated electricity market will influence national energy policies, which will then have to take into account increased international impacts and reactions. Such factors were negligible in a system with closed regional power systems. In this context, it is interesting to analyse the impact of an integrated European electricity market.

This paper presents the large-scale simulation model EIREM (**E**uropean **I**nter**R**egional **E**lectricity **M**odel), which is able to evaluate the possible effects of a single market especially on the interregional generation structure and the alteration of power trade within Europe. This paper also presents the numerical assumptions used for the calculations in detail. Afterwards the numerical results are presented and interpreted.

EIREM, a multi-period, multi-region linear programming model of the European power supply, was used to analyze the impacts of a common electricity market. EIREM models a long-term perspective up to the year 2020, in order to be able to describe the structural change in the European electricity sectors. With a technical lifetime of thermal power plants lying between 30-40 years, the structural changes in the electricity sector in general occur slowly. But, structural change can be accelerated due to historical investment cycles leading to an increased replacement of power plants. Therefore, an appropriate simulation model for structural changes in the electricity sector has to be long-term and also based on the historically given vintage structure. A vintage structure of the power system is necessary, especially when calculating the costs involved, because the vintage structure indicates the deviation between the natural capacity replacement and the replacement induced by energy policy.

The computations lead to the following conclusions: Over time the opening of national electricity markets in Europe leads to a reallocation of power generation in the various regions and to a change in the fuel mix. As a result of market opening, power generation is especially relocated from Germany and France to Italy and Belgium/Netherlands. A relocation of power generation to countries with a high share of nuclear power or access to natural gas can be found. Power plants on gas basis will gain importance due to their comparatively low capital cost.

Earlier quantitative studies detailing the likely effects of an internal European electricity market are surprisingly few in number. The only simulation-based analyses known to the author are presented in a study by the Commission of the European Communities (1992) and in Amundsen et al. (1994). The first study differs from the current article in its failure to disclose the formal model. Furthermore, capacities of regional power plants and transmission lines are considered exogenous, the capacities by plant type are not differentiated by vintage, and effects on the development of regional power plant structures and transmission capacities are not simulated. Therefore, long-term structural effects can not be simulated. Similar concerns affect the second study, which also simulates generation and power transmission with a given stock of generation and transmission capacity.

Simulation results reject the widely-held conception that a European common market for electricity would lead to a dramatic increase in international electricity trade. On the contrary, the importance of foreign trade for covering electricity demand diminishes in the long run or stagnates on approximately the same level. The import shares arising from a scenario of unrestricted electricity trade stay well below the limits implied by the European Commission's Internal Market directive. They do not necessarily increase over time, because competitive pressures present in the Internal Market lead to a partial convergence of costs, thus reducing the incentives for trade.

Keywords: Linear Programming Model; European Power Systems; Interregional electricity trade

JEL-Classification: Q4, C61, F21.

1 Introduction

The introduction of a single electricity market in Europe has sparked a sometimes heated debate over the possible consequences concerning the volume of power trade within Europe and the future generation structure. Especially the remarkable differences in the existing power systems lead to speculation about future development. Substantial structural deviations exist in the use of energy carriers (Table 1), generation technologies and the vintage structure of power plants. It can be seen that the unique characteristic of the German (GE) power generation industry is a strong dependence on brown coal. Other important features of the national electricity supply systems are a high share of nuclear power in France (FR), and the absence of nuclear power in Italy (IT), combined with a strong dependence on oil. Gas plays a significant role only in the United Kingdom (UK) and the Benelux-region (BNL) (which in this case refers to: the Netherlands). Generation in the Alpine-region (AU/SUI) (Austria and Switzerland) consists mainly of hydro-electric power. Finally, on the Iberian Peninsula (IB) (Spain and Portugal) power generation is based on a mix of hard coal, nuclear and hydro-electric power.

These structural features, one should expect, lead to regional differences in marginal generation costs with important impacts on the initial situation of competition. Therefore, a tool is desired to simulate the effects of a common electricity market and to compare them with a fictitious maintenance of the status quo. This study outlines a simulation model of the European electricity supply industry and applies it to evaluate the effect of opening the national electricity markets in the European Union.

Table 1: Generation structure in Europe by energy carrier in 1995 [%]*

	GE	FR	UK	IT	AU/SUI	BNL	IB
Hard Coal	24	5	44	9	3	32	35
Lignite	30	0	0	1	1	0	7
Oil	1	1	11	62	1	0	8
Gas	7	1	16	9	7	32	0
Nuclear	34	78	28	0	19	34	30
Hydro Power	4	16	2	21	69	2	20

Source: UNIPEDE, own calculations.

The effect of market opening will be contrasted with a baseline of ‘closed’ national electricity markets. ‘Closed’ means that each region’s share of electricity imports from total demand will be restricted not to exceed its current level. In accordance with market opening, the Council of Energy Ministers recently passed a directive allowing customers with an electricity demand above a certain threshold to purchase electricity from foreign suppliers. More specifically, a timetable has been set establishing the free choice of supplier by 1999 for customers with a demand larger than 40 GWh, and by 2005 for customers with a demand larger than 9 GWh. These provisions can be translated into certain percentages of each national market to be opened up to foreign suppliers. For 1999 an import share of approximately 23% would be possible and of 33% in 2005.

In contrast to this schedule, the Internal Market scenario used in this paper is based on the assumption that import restrictions are *entirely* abolished. A comparison of imports resulting from such an unrestricted scenario with the limits specified in the Council's directive should be particularly interesting.

Earlier quantitative studies detailing the likely effects of an internal European electricity market are surprisingly few in number. The only simulation-based analyses known to the author are presented in a study by the Commission of the European Communities (1992) and in Amundsen et al. (1994). The first study differs from the current article in its failure to disclose the formal model. Furthermore, capacities of regional power plants and transmission lines are considered exogenous, the capacities by plant type are not differentiated by vintage, and effects on the development of regional power plant structures and transmission capacities are not simulated. Therefore, long-term structural effects can not be simulated. Similar concerns affect the second study, which also simulates generation and power transmission with a given stock of generation and transmission capacity.

2 Model Characteristics and numerical assumptions

The model presented in this paper is EIREM (**E**uropean **I**nter**R**egional **E**lectricity **M**odel). The model is designed to simulate the effects of a common European electricity market. In brief, EIREM is a multi-period multi-region linear programming model of the European power supply. The objective function to be minimized comprises the discounted, cumulated generation and transmission costs of all regions and time periods in the model. Model results depend strongly on numerical assumptions such as investment, fuel cost and transmission losses. Therefore, they are described before the formal model and model results are presented.

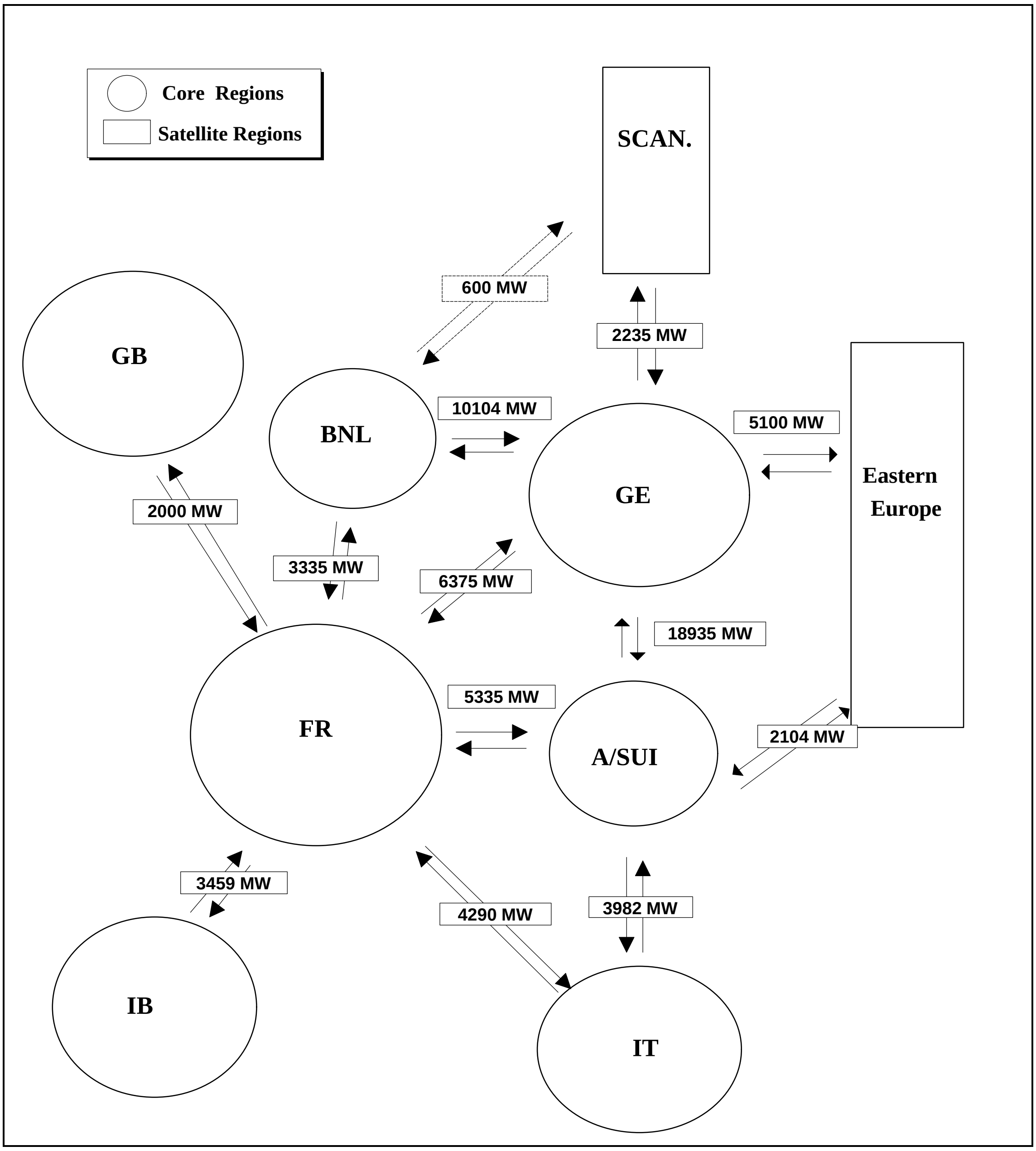
Model Regions and Transmission Lines:

The regions modeled are Germany, France, Great Britain, Italy Belgium/Netherlands/Luxembourg, Austria/Switzerland and Portugal/Spain - as „core regions" (Figure 1). Core regions are characterized as significantly influencing European power trade and, therefore, their power demand and plant stock are modeled in detail. In addition to these countries, Scandinavia and Eastern Europe are incorporated as „satellite regions". These regions are taken into account due to their direct or indirect effect on interregional power trade, but are less important than the core regions. Imports of electricity by satellite regions are given exogenously, while exports of power into core regions are computed with respect to power import prices and are restricted by an upper bound. Electricity trade between core regions on the other hand is endogenously determined.

The effects of a common electricity market on power plant and generation structure in the core-regions depend highly upon the cost of power transmission. Essentially, these costs are determined by transmission line investment and transmission losses in the grid. For this reason, both existing back-to-back stations connecting different regions and possible extensions of transmission capacity are taken into account. The costs of upgrading existing lines are naturally much higher, if the capacity of regional lines has to be strengthened over and above the extension of back-to-back stations. The bilateral transmission capacities as presented in figure 1 represent the maximum technical possible use of existing back-to-back stations. The economically defensible use is assumed to be 50% of this capacity. In addition, EIREM takes notice of transmission losses, which are assumed to be 10% per 1000 km in a 380kV high-voltage-grid.

The transmission distance between two regions is measured by taking the location of the regional power generation and consumption centers. The average distance is computed as the mean value of the distances of neighboring generation and consumption centers. For example, the average transmission distance from France to Germany amounts to 210 km. But, in the opposite direction the average distance comes to 220 km. As can be seen from this example, asymmetries are taken into account, but they are not pronounced due to a leveling of mean values.

Figure 1: Interconnections of core regions and satellite regions



Power demand:

The model minimizes overall generation and transmission costs subject to a given demand profile. Power demand is taken into account utilizing twelve different load blocks dependent upon the time of day, as well as the time of year. Due to differences in the seasonal availability of power plants, especially hydro-electric power, three seasons are distinguished (summer, winter, interseasonal time). These load blocks are applied simultaneously to all regions, an assumption necessary to identify potentials in interregional trade. Power demand within core regions is analyzed on the basis of national load diagrams taken every third Wednesday of the month. All other days are developed in a simulation due to a lack of information. Weekdays are assumed to correspond with the third Wednesday of the month on average, with a normally distributed deviation from the yearly average. The same procedure is followed with respect to weekends, differing only in that average demand is assumed to be 15% less on Saturdays and 20% less on Sundays compared to weekdays.

It is assumed that the growth rates of power demand lie significantly under the average growth rate in the period 1970-1990 (3,4%). All load blocks grow with the same rate, so that their relationship remains constant. The average growth rates in all regions decline over time (Table 2).

Table 2: Public Power Demand in Core Regions [TWh]

	1995	2000	2005	2010	2015	2020
GE	435	460	483	508	527	547
FR	399	434	465	496	526	557
GB	326	355	383	404	425	446
IT	254	284	316	338	359	379
A/SUI	99	107	115	123	132	141
BNL	144	154	164	174	184	193
IB	171	205	235	264	291	318

Source: PROGNOS, UNIPEDE, own calculations.

Power Plant Types and Vintage Structure:

The model represents a long-term perspective up to the year 2020, in an effort to describe the structural change in the electricity sector. With the technical lifetime of thermal power plants lying between 30-40 years, the structural changes in the electricity sector occur rather slowly. But, structural change can be accelerated due to historical investment cycles, which lead to larger replacements of power plants in the power system. Therefore, an appropriate simulation model for structural change in the electricity sector must be long-term and based on the historically given vintage structure. Power stations (MW) existing in core regions are differentiated according to power plant type and vintage. The EIREM-Model includes all power stations of public supply coming into operation after 1950 and still capable of generating electricity in 1995. The following plant types are distinguished:

Hard Coal	Hard Coal (conventional technology)
ICGCC	Hard Coal (combined-cycle technology)
Hard Coal /Gas	Bivalent Generation with Hard Coal and Gas
Lignite	Brown Coal (conventional technology)

Oil	Oil (conventional technology)
GTCC	Natural Gas (combined-cycle technology)
Gas-Turbine	Gas-turbine generation
Nuclear	Nuclear power
Hydro_L	Run of River
Hydro_P	Storage and pumped storage

Since it is impractical to incorporate all future power plant technologies, the above-listed types were taken as a representative sample of employable plants. Lignite gasification technology was not taken into consideration due to comparatively high investment costs and negligible improvements in efficiency.

One essential detail of the EIREM-Model is the computation of optimal power plant operation and replacement simultaneously over several time periods. This results in a sequence of consistent decisions describing the evolutionary development of generating capacity. The quality or practical relevance of the model's results are primarily dependent upon whether determinants for plant operation and replacement were appropriately considered. For example, in addition to factors such as vintage and fuel prices, specific features of some plant technologies are of particular importance. The following features concerning economical and technical specifications are taken into account to obtain a realistic picture:

- technical lifetime (in years),
- period of depreciation (in years)
- specific labor costs (in DM per MW and year),
- specific maintenance and repair costs (in DM per MW and year),
- average seasonal availability (in % of installed capacity),
- efficiency (in %) ,
- specific capital costs (in DM per kW),
- other variable costs (in PF per kWh).

Except for availability and maintenance and repair costs all technological parameters concerning a specific power station with a certain vintage are constant over the plant's lifetime. Availability is assumed to decrease, while maintenance and repair costs increase with the age of a plant. A plant's actual lifetime is not given exogenously, but is influenced by the economic calculus of the decision maker. The decision must be made, whether to keep an existing power station in operation with rising maintenance and repair costs and lower availability, or to replace it.

Investment cost are assumed to remain more or less constant over the course of time, while the efficiency of thermal power plants increases significantly (Tables 3 and 4). Slight decreases in investment costs occur, because of increasing competition on the world power plant market. Efficiency will increase due to the development of new materials in turbine construction.

Table 3: Investment Cost in constant Prices [ECU/kW]

	1995	2000	2005	2010	2015	2020
Hard Coal	1125	1125	1119	1113	1113	1113
ICGCC	1400	1400	1392	1385	1385	1385
Hard Coal/Gas	1100	1100	1094	1088	1088	1088
Lignite	1250	1250	1248	1245	1245	1245
Oil	925	925	917	909	909	909
GTCC	575	575	570	565	565	565
Gas-Turbine	325	325	322	319	319	319
Nuclear	2150	2150	2097	2045	2045	2045

Source: information of utilities, own calculations.

Table 4: Thermal efficiency [%]

	1995	2000	2005	2010	2015	2020
Hard Coal	42.5	45.5	46.5	47.5	48.5	49.5
ICGCC	45.8	45.8	48.0	49.0	50.0	51.0
Hard Coal/Gas	45.4	45.5	48.0	49.0	50.0	51.0
Lignite	41.5	43.0	44.5	45.5	46.5	47.5
Oil	44.0	44.5	45.0	47.0	47.2	47.4
GTCC	57.5	60.0	61.5	62.0	62.5	63.0
Gas-Turbine	38.0	38.5	39.0	39.5	40.0	40.5
Nuclear	34.0	36.0	36.0	36.0	36.0	36.0

Source: information of utilities, own calculations.

Critical parameters for the model results are the fuel costs and their interregional differences (Tables 5 and 6). Fuel prices can differ between regions for several reasons. Cif-import prices can vary between regions due to distortions in competition or differences in transportation costs. The latter can also influence fuel prices within a region. Competition will, however, reduce these differences, which is taken into account by decreasing surcharges on transportation costs.

Table 5: Fuel Prices in Germany [ECU/GJ]

	1995	2000	2005	2010	2015	2020
Hard Coal	1.621	1.906	2.006	2.116	2.260	2.414
Lignite	1.689	1.689	1.689	1.689	1.689	1.689
Oil	2.280	2.822	2.936	3.297	3.537	3.831
GTCC	2.950	3.105	3.439	3.856	4.351	4.875
Gas-Turbine	3.611	3.801	4.210	4.720	5.326	5.967
Nuclear	1.114	0.845	0.829	0.814	0.814	0.814

Source: PROGNOS, IEA, own calculations.

Table 6: Regional Fuel Price Differences (status quo) [Germany = 1]

	1995	2000	2005	2010	2015	2020
Hard Coal						
FR	1.00	1.00	1.00	1.00	1.00	1.00
A/SUI	1.66	1.46	1.44	1.42	1.42	1.42
BNL	0.95	0.95	0.95	0.95	0.95	0.95
E/P	1.08	1.08	1.07	1.07	1.07	1.07
GB	0.95	0.95	0.95	0.95	0.95	0.95
IT	1.32	1.10	1.00	1.00	1.00	1.00
Oil						
FR	0.98	0.98	0.98	0.98	0.98	0.98
A/SUI	1.01	1.01	1.01	1.01	1.01	1.01
BNL	0.92	0.92	0.92	0.93	0.93	0.93
E/P	0.89	0.89	0.89	0.90	0.90	0.90
GB	0.70	0.70	0.71	0.72	0.72	0.72
IT	0.96	0.96	0.96	0.96	0.96	0.96
Gas						
FR	1.00	1.00	1.00	1.00	1.00	1.00
A/SUI	1.05	1.05	1.05	1.05	1.05	1.05
BNL	0.95	0.95	0.95	0.95	0.95	0.95
E/P	1.00	1.00	1.00	1.00	1.00	1.00
GB	0.94	0.90	0.86	0.86	0.86	0.86
IT	0.98	0.98	0.98	0.98	0.98	0.98
Nuclear						
FR	0.63	0.63	0.64	0.66	0.66	0.66
A/SUI	0.79	0.79	0.80	0.80	0.80	0.80
BNL	0.63	0.63	0.64	0.66	0.66	0.66
E/P	0.63	0.63	0.64	0.66	0.66	0.66
GB	0.75	0.75	0.76	0.77	0.77	0.77
IT	1.00	1.00	1.00	1.00	1.00	1.00

Source: IEA, own calculations.

3 Model Formulation

The formal model explained below has been simulated using GAMS (Release 2.25) and possesses in the status quo scenario without taxes 122,847 variables and 38,741 restrictions. The model solver used is GAMS/OSL,Release 2.0 (Brooke et al. (1992)).

Objective function:

The objective function to be minimized is the total discounted cost within the core regions *r*. The methodical approach is based on the economic paradigm that a workable competitive system leads to the same allocation as a centralized optimization. This means in both cases that the given power demand will be met with the least-cost resource input. Therefore, this procedure represents a competitively organized electricity system by means of an optimization approach. Parameter δ_t denotes the discount factor in period t. Total costs are the sum of total operating costs (TOC), total labor costs (TLC), maintenance and repair costs (TIURC), capital costs (TCC), expenses for electricity imports from satellite regions (TIMC), cost of transmission capacity additions (TTC), as well as potential payments for a CO_2-emission tax: ECTAX.

(1)
$$
\begin{aligned}
TDC = & \sum_r \sum_t d_t \cdot \left(TOC_{t,r} + TLC_{t,r} + TIURC_{t,r} + TCC_{t,r} + TIMC_{t,r} + ECTAX_{t,r} \right) \\
& + \sum_t d_t \cdot TTC_t
\end{aligned}
$$

Cost equations:

Total operating costs comprise fuel costs and all other costs that depend on actual power generation:

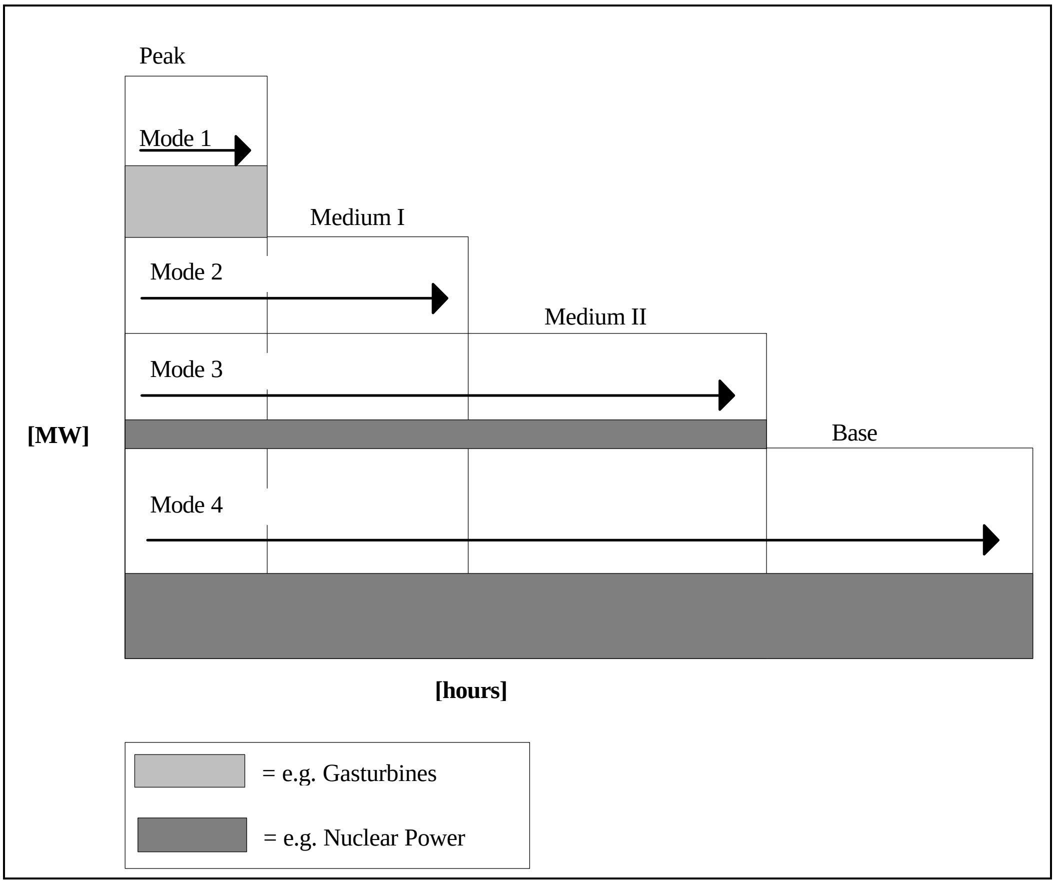
(2)
$$
\begin{aligned}
TOC_{t,r} = & \sum_j \sum_{v \le t} \sum_s \sum_{bp} \frac{PRODUC_{j,v,s,bp,t,r} \cdot (dur_{s,bp} + startdur_{j,s,bp})}{eta_{j,v,r}} \cdot pfuel_{j,t,r} \\
& + \sum_j \sum_{v \le t} \sum_s \sum_{bp} PRODUC_{j,v,s,bp,t,r} \cdot (dur_{s,bp} + startdur_{j,s,bp}) \cdot ovarc_{j,t,r}
\end{aligned}
$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

Fuel prices and other specific variable costs enter the model through the exogenous parameters *pfuel* and *ovarc*. Total fuel demand of a plant within a certain period of time can be computed from the electricity generated and the plant's efficiency (*eta*). Total fuel requirement of the system in region *r* in period *t* is the sum of the seasonal (index *s*) fuel consumption of all different power plant types *j* with vintage $v \le t$. The actual work is the product of power and the duration of its employment. Variable *PRODUC* measures power output of plant *j* with vintage *v* in season *s* and mode of operation *bp* in year *t* and region *r*. Index *bp* denotes the mode in which a plant operates. With four load-categories *b* there are also four modes in which a power plant can operate (see Rogers, J.S. and Rowse, J.G. (1989)). If a power plant operates in the largest mode, it supplies power continuously over all load-categories *b*. Thus, it is called the „base-load" mode. The following mode decreases by the duration of the previous load block.

Figure 2: Different load-categories



The plant's time of operation in mode *bp* includes the duration of the mode of operation (*dur*) and the time needed to bring a plant unit into operation (*startdur*). Generally speaking, however, the latter can be neglected in a yearly analysis. Specific maintenance and repair costs (*iurcost*) of plant *j* are determined by its age. Total maintenance and repair costs of a region are summed up for all plant types and vintages:

$$(3)\quad TIURC_{t,r} = \sum_{j} \sum_{v \le t} iurcost_{j,v,t,r} \cdot CAPA_{j,v,t,r}$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

Total labor costs are a function of installed capacity as well:

$$(4)\quad TLC_{t,r} = \sum_{j} \sum_{v \le t} labcost_{j,v,t,r} \cdot CAPA_{j,v,t,r}$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

Additions to transmission capacity between two regions show regional differences in specific costs per MW. These specific costs per MW (*tc*) depend on the kind of transmission line (*tl*), on the year of addition (*tn*) and on the regions involved. The kind of addition is determined by the capacity situation of both regional lines and back-to-back stations. According to this situation more or less costly measures have to be taken to upgrade transmission capacity. Variable TCADD stands for transmission capacity of kind *tl* built in year *tn* connecting core regions (*r*,*reg*) and/or satellite regions (*satr*):

$$
\begin{aligned}
TTC_t = & \sum_{r} \sum_{reg} \sum_{tn \le t} \sum_{tl} tc_{tl,tn,t,r,reg} \cdot TCADD_{tl,tn,r,reg} \\
& + \sum_{r} \sum_{satr} \sum_{tn \le t} \sum_{tl} tc_{tl,tn,t,r,satr} \cdot TCADD_{tl,tn,r,satr}
\end{aligned} \tag{5}
$$

(t = 1995,..., 2050).

Total capital costs are determined by the cost of investment in new capacity, as well as the fixed costs of existing plants. They are defined as fixed, since no decision in the future will influence them. Fixed costs of existing plants must be taken into account to get a clear picture of the development of costs through time. Otherwise total costs would be too low in initial years compared to later periods. Capital costs include the costs of desulphurization and denitrification of flue gases according to national law, as well. After the plant has been written-off, which usually occurs before the plant is taken out of operation, no further capital costs are incurred. Capital costs are accounted for through their annuity (*cc*), which depends on the investment cost of plant *j* with vintage *v*, the interest rate and the age of the power station:

$$
\begin{aligned}
TCC_{t,r} = & \sum_{j} \sum_{tp} cc_{j,tp,t,r} \cdot inicap_{j,tp,r} \\
& + \sum_{j} \sum_{tn \le t} cc_{j,tn,t,r} \cdot factor_{j,tn,tn,r} \cdot NUM_{j,tn,tn,r}
\end{aligned} \tag{6}
$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

The matrix *inicap* refers to the historical stock of power plants in the base year of optimization. The index *tp* comprises the sum of all vintages up to the baseyear. Adding new capacity within the period of optimization is taken into account by the variable *NUM*. *NUM* stands for the number of units built in period *tn*. Finally, the parameter *factor* accounts for the capacity of the different units in MW.

Total cost must contain expenses for electricity imports (*PIMP*) from satellite regions. Import prices for power (*pim*) orient themselves on avoided variable costs of generation in the importing region.

$$
TIMC_{t,r} = \sum_{s} \sum_{b} \sum_{satr} PIMP_{s,b,t,satr,r} \cdot duration_{b,s} \cdot pim_{s,b,t,satr,r} \tag{7}
$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

Demand restrictions:

$$\sum_{bp\geq b}\sum_{j}\sum_{v\leq t} PRODUC_{j,v,s,bp,t,r}\cdot e_{r,r} + \sum_{reg\neq r}\left(PT_{s,b,t,reg,r} - \frac{PT_{s,b,t,r,reg}}{e_{r,reg}}\right) \tag{8}$$
$$+ \sum_{reg\neq r}\left(shterm_{s,b,t,reg,r} - shterm_{s,b,t,r,reg}\right) + \sum_{satr}\left(PIMP_{s,b,t,satr,r} - \frac{PEXP_{s,b,t,r,satr}}{e_{r,satr}}\right) \geq d_{s,b,t,r}$$

(t = 1995,..., 2050;

s = summer, interseasonal time, winter;

b = high, medium, low, base;

r = Germany, France, Austria/Switzerland, Benelux).

The power demand of region *r* is either met by the power supply within the region or by net power imports. The variable *PT* measures the net power transmitted between the core regions caused by systematic cost advantages; due to transmission losses, it is necessary to include exports as gross power transmissions (see Rogers, J.S. and Rowse, J.G. (1989)). In the EIREM-model short-term optimization of power transfers between regions are not endogenously determined. Such short-term transfers arise, when power plants experience temporary outages or surprise changes in demand occur. Using historical transfers as a model, the parameter *shterm* has been incorporated to account for these short-term fluctuations and is fitted proportionally to the development of power demand in the regions in question. Additionally, one assumes that such transfers experience a fixed relationship with respect to the regions´grid load.

The parameter *e* measures the efficiency of the transmission link between two regions and its value is strictly less than unity. The domestic power generation is also scaled by factor *e*, which corresponds to transmission losses within region *r*. *PIMP* stands for the power imports from the satellite regions and *PEXP* represents the power exports to them. Transmission links exist between Germany and neighboring regions. The latter are interconnected, as well. Figure 1 gives a simplified sketch of these interconnections. The power demand of the satellite regions (power exports of the core regions) is given exogenously, where power is sold for an exogenously determined price. Parameter $d_{s,b,t,r}$ denotes the demand for electricity (MW) in season *s* of period *t*, load characteristic *b* and region *r*.

The available installed capacity and the difference between net power imported and gross power exported has to meet the expected peak demand plus a certain reserve margin. In equation (9) it is assumed that the peak demand will occur during the winter season (*s*). In the program a subroutine identifies the period with the peak demand automatically. A regional reserve margin is required to maintain security of supply. Availability depends on the power plant’s technical specifications, on the season and on the age of the plant. While seasonal differences in availability are caused by maintenance interruptions, which mainly occur in the summer season, increasing age reduces availability due to the need for intensified maintenance and repair.

$$(9)\quad e_{r,r}\cdot\sum_{j}\sum_{v\le t} avail_{j,v,s,t,r}\cdot CAPA_{j,v,t,r}+\sum_{reg\ne r}\left(PT_{s,b,t,reg,r}-\frac{PT_{s,b,t,r,reg}}{e_{r,reg}}\right)$$
$$+\sum_{reg\ne r}\left(shterm_{s,b,t,reg,r}-shterm_{s,b,t,r,reg}\right)+\sum_{satr}\left(PIMP_{s,b,t,satr,r}-\frac{PEXP_{s,b,t,r,satr}}{e_{r,satr}}\right)\ge\left(1+prr_{r}\right)\cdot d_{s,b,t,r}$$

(j = HC,..., HYD_P;

v =1955,..., t;

t = 1995,..., 2050;

s = winter;

b = high;

r = Germany, France, Austria/Switzerland, Benelux).

Capacity restrictions:

The capacity of plant *j* with vintage *v* depends on the initial capacity *inicap* and capacity adjustments in subsequent years *tn*. Capacity adjustment can either mean an addition to or replacement of existing plants. The variable $NUM_{j,v,tn,r}$ counts for the number of plants with size „$factor_{j,v,tn,r}$“ that will be added or replaced.

$$(10)\quad CAPA_{j,v,t,r}=inicap_{j,v,r}+\sum_{tn\le t} factor_{j,v,tn,r}\cdot NUM_{j,v,tn.r}\ .$$

(j =HC,..., HYD_P;

v = 1955,..., t;

t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

The output from each plant cannot exceed its available capacity:

$$(11)\quad \sum_{bp} PRODUC_{j,v,s,bp,t,r}\le avail_{j,v,s,t,r}\cdot CAPA_{j,v,t,r}\ ,$$

(j =HC,..., HYD_P;

v = 1955,..., t;

s = summer, winter, interseasonal time;

t = 1995,...,2050;

r = Germany, France, Austria/Switzerland, Benelux).

Fuel input and generation restrictions:

Restrictions in fuel input are either due to political standards or due to natural limitations. Lignite, for example, can only be found in Germany and Austria. The amount of lignite (*BC*) used in generation, can be calculated from the electricity produced divided by the plant's efficiency (*eta*).

$$(12)\quad \sum_{v\leq t}\sum_{s}\sum_{bp}\frac{\mathrm{PRODUC}_{j,v,s,bp,t,r}\cdot(\mathrm{dur}_{s,bp}+\mathrm{startdur}_{j,s,bp})}{\mathrm{eta}_{j,v,r}}=\mathrm{BC}_{t,r}\,,$$

(t = 1995,...,2050;

r = Germany, France, Austria/Switzerland, Benelux

j = BC).

Power production with lignite can be varied only to a small extent. The amount of lignite used for generation is therefore limited by an upper and a lower bound. Similarly, input of other fossil fuels is restricted. These limitations are varied with the different political scenarios to be analyzed. A different kind of restriction concerns hydroelectric capacity, as the output from a hydroelectric plant cannot exceed the energy available in the water supplies. Pumped storage plants have a especially low average load factor:

$$(13)\quad \sum_{v\leq t}\sum_{s}\sum_{bp}\mathrm{PRODUC}_{j,v,s,bp,t,r}\cdot\mathrm{dur}_{s,bp}\leq \mathrm{lfhyd\_P}_{r}\cdot\mathrm{TOTCAP}_{j,t,r}\,,$$

(t = 1995,...,2050;

r = Germany, France, Austria/Switzerland, Benelux

j = HYD_P).

Parameter *lfhyd_P* represents the plant's load factor, which is the quotient of the average yearly production divided by maximum production (see Turvey, R. and Anderson, D. (1977)). The variable *TOTCAP* counts for the total capacity of a certain technology.

Interregional transmission constraints:

In every season, load, period and region the sum of power flows in opposite directions is restricted by the sum of the initial transmission capacity in 1995 (*initrans*) and capacity additions (*TCADD*). Parameter *griduse* restricts maximum transmission capacity to an economically effective level. It must be sufficient to accommodate gross power flows. Comparative cost differences among the regions and transmission losses prevent the model from transmitting power in opposite directions during the same load-period. Hence, nonlinearities due to efficiency improvements in the case of simultaneous transmissions will not occur.

$$\frac{PT_{s,b,t,r,reg} + PT_{s,b,t,reg,r}}{e_{r,reg}} + \frac{shterm_{s,b,t,r,reg} + shterm_{s,b,t,reg,r}}{e_{r,reg}} \tag{14}$$
$$\leq griduse_{r,reg} \cdot \left(initrans_{r,reg} + \sum_{tn \leq t} \sum_{tl} TCADD_{tl,tn,r,reg} \right)$$

(s = summer, winter, interseasonal time;

t = 1995,..., 2050;

b = high, medium, low, base;

r, reg = Germany, France, Austria/Switzerland, Benelux).

$$\frac{PIMP_{s,b,t,satr,r} + PEXP_{s,b,t,r,satr}}{e_{r,satr}} \leq griduse_{r,satr} \cdot \left(initrans_{r,satr} + \sum_{tn \leq t} \sum_{tl} TCADD_{tl,tn,r,satr} \right) \tag{15}$$

(s = summer, winter, interseasonal time;

t = 1995,..., 2050;

b = high, medium, low, base;

r = Germany, France, Austria/Switzerland, Benelux;

satr = Great Britain, Scandinavia, Eastern Europe, Italy).

Concerning the extension of cross-border transmission capacity between two regions, three different steps have been distinguished. The first and, in terms of costs, cheapest step refers to the upgrading of back-to-back stations. Parameter *tl1up* marks the upper limit of this measure. Additional transmission capacity beyond the improvement of back-to-back stations can be obtained by improving parts of national transmission lines, which is limited by *tl2up*. If these measures are still insufficient, extensive sections of national lines will have to be upgraded. There is no upper limit for this.

$$\sum_{tn \leq t} TCADD_{tl,tn,r,allr} \leq tl1up_{r,allr} \tag{16}$$

(r = Germany, France, Austria/Switzerland, Benelux;

allr = Germany, France, Austria/Switzerland, Benelux,

Great Britain, Scandinavia, Eastern Europe, Italy

tl = tl1up).

(17) $\sum_{tn \le t} TCADD_{tl,tn,r,allr} \le tl2up_{r,allr}$

(r = Germany, France, Austria/Switzerland, Benelux

allr = Germany, France, Austria/Switzerland, Benelux,

Great Britain, Scandinavia, Eastern Europe, Italy

tl = tl2up).

Power imports from satellite regions are restricted as well:

(18) $\sum_{s}\sum_{b}\sum_{r} PIMP_{s,b,t,satr,r} \cdot duration_{b,s} \le imup_{t,satr}$

(t = 1995,..., 2050;

satr = Great Britain, Scandinavia, Eastern Europe, Italy).

Environmental taxes:

The model also allows for an analysis of taxation's effects on energy input and CO_2 emissions. $ECTAX_{tr}$ measures the total tax revenue from a combined energy/CO_2 tax proposed by the European Commission. Parameters *tecCO2*, *tecMWh* and *tecHYD* stand for the different tax rates and parameter *co2fac* represents the fuel-specific CO_2-emission:

$$\begin{aligned}
& ECTAX_{t,r} = tecCO2_{t,r} \cdot \sum_{j}\sum_{v}\sum_{s}\sum_{bp} co2fac_{j} \cdot \frac{PRODUC_{j,v,s,bp,t,r} \cdot dur_{s,bp}}{eta_{j,v,r}} \\
(19)\quad & + tecMWh_{t,r} \cdot \frac{8760}{1000000} \cdot \sum_{johydro}\sum_{v}\sum_{s}\sum_{bp} PRODUC_{johydro,v,s,bp,t,r} \cdot dur_{s,bp} \\
& + tecHYD_{t,r} \cdot \frac{8760}{1000000} \cdot \sum_{hydro}\sum_{v}\sum_{s}\sum_{bp} PRODUC_{hydro,v,s,bp,t,r} \cdot dur_{s,bp}
\end{aligned}$$

(t = 1995,..., 2050;

r = Germany, France, Austria/Switzerland, Benelux).

4 Effects of an Internal Market for Electricity

In running the „Internal Market“ simulations, it is assumed that competitive pressure will lead to a convergence of capital and fuel costs currently differing across regions. The economic reasoning behind this is that price differentiation and overly demanding technical specifications - which may occur in separated markets - cannot be sustained in an open market with arbitrage possibilities. More specifically, it is assumed that cost differences with respect to the 'best practice' in Europe will be halved by the year 2010. In addition, it is assumed that the discount rate utilized in the investment calculus is higher in the open market case (8%) than in the closed market case (5%), reflecting a premium for increased market risk. The power plant capacities for nuclear and hydroelectric plants are exogenously determined (Table 7). For most countries upper bounds exist for the maximum nuclear capacity, which can be installed. The potential for expansion in hydroelectric capacity is restricted by geographical factors and the employment of nuclear power is dependent, first and foremost, upon political decision makers. Therefore, these two power plant types are not freely utilizable in optimizing power plant expansion. The optimization calculation also includes the usage of available capacity for primary energy sources.

Table 7: Overview of the "Internal Market"

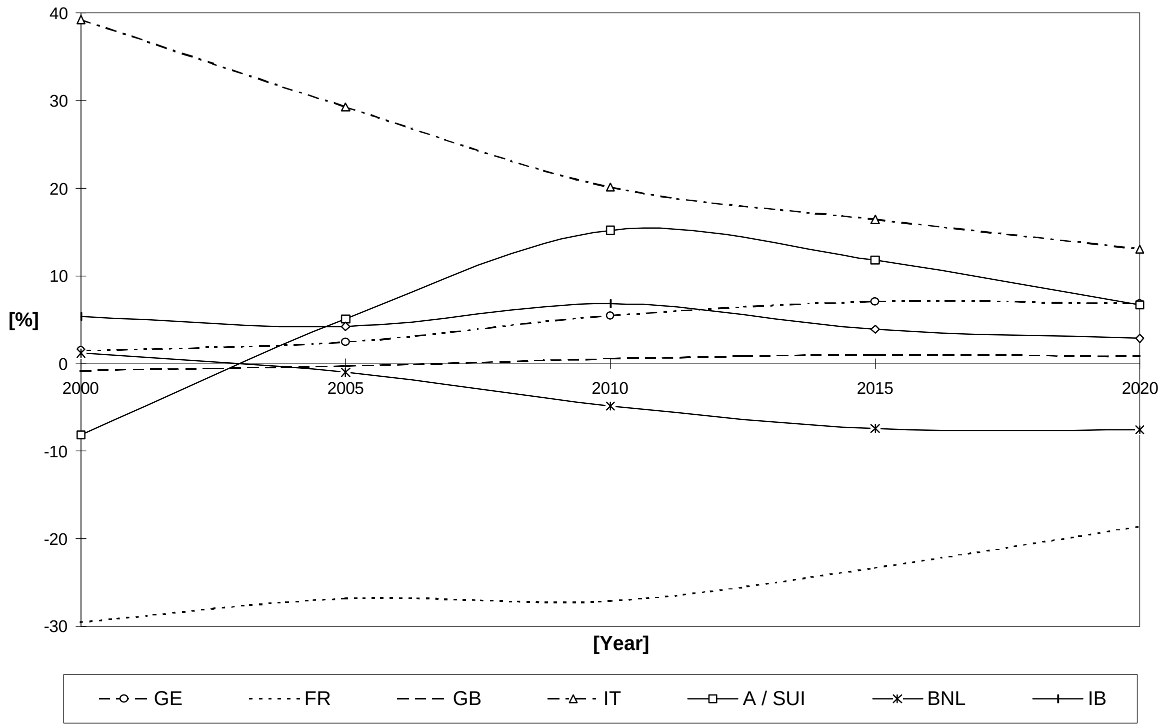
	Restriction	Freely Optimized
Germany		
Hard Coal		yes
Lignite	Fuel Input: up to 170 Mio. t	Capacities
Oil		yes
Gas		yes
Nuclear Power	fixed capacity: 21218 MW	Generation
Hydro Power	Capacity development	Generation
France		
Hard Coal		yes
Oil		yes
Gas		yes
Nuclear Power	Increasing upper bound: from 58430 MW (1995) to 79300 MW (2020)	Generation
Hydro Power	Capacity development	Generation
Great Britain		
Hard Coal		yes
Oil		yes
Gas		yes
Nuclear Power	max. capacity: 13000 MW	Generation
Hydro Power	Capacity development	Generation
Italy		
Hard Coal		yes
Oil		yes
Gas		yes
Nuclear Power	fixed capacity: 0 MW	Generation
Hydro Power	Capacity development	Generation
Austria/Switzerland		
Hard Coal		yes
Lignite	Fuel Input: up to 2 Mill. TCE	Capacities
Oil		yes
Gas		yes
Nuclear Power	max. capacity: 2990 MW	Generation
Hydro Power	Capacity development	Generation
Benelux		
Hard Coal		yes
Oil		yes
Gas		yes
Nuclear Power	max. capacity: 6500 MW	Generation
Hydro Power	Capacity development	Generation
Iberian Peninsula		
Hard Coal		yes
Lignite	Fuel Input: up to 5.38 Mill. TCE	Capacities
Oil		yes
Gas		yes
Nuclear Power	max. capacity: 7800 MW	Generation
Hydro Power	Capacity development	Generation

General development of electricity trade

A frequently mentioned statement claims that a European common market for electricity would lead to a dramatic increase in international electricity trade. The simulations here do not support this hypothesis; on the contrary, the relative importance of foreign trade for covering electricity demand declines (Italy and France) stagnates on nearly the same level (Figure 3). What appears to be a surprising result can be explained by the gradual merging of frameworks, in which electricity suppliers operate, and by restrictions in the field of transmission. If an increased harmonization of input factor prices occurs, especially the fuel and investment costs of the power plants and the costs of electricity transmission gain in importance.

Capital and fuel costs combined total to approximately 85 percent of the entire generation costs. The tendency toward harmonization of these costs stimulates the interregional assimilation of generation costs for these power plants. In the event the transmission costs are greater than the difference in generation costs, electricity trade is viewed as uneconomical. Thus, relatively small transmission losses can decidedly impact electricity trade in the short term and power plant locationing in the long term. On the other hand, pressure towards harmonization continues, as long as the generation cost differences are higher than the transmission costs. Restrictions in transmission, especially transmission losses, prevent a perfect merging of generation costs in the common market and limit the trade volume.

Figure 3: Net import and export shares of regional electricity demand ("Internal Market")



In the future Germany will continue to cover only a small portion of its electricity demand with imports, but with a slightly increasing trend toward larger import shares. France will remain the largest net electricity exporter in Europe - although to a lesser extent, resulting from decreasing excess capacity in nuclear power allotted for export. Austria and Switzerland will become net importers between 2000-2005 and thereafter. The primary reason for this development is a lack of expansion potential for hydroelectric power and a growing distaste for new power plants, especially in Austria. In the next few years, the Benelux countries will continue their role as net importers. At about 2005 their electricity imports will noticeably diminish and this region will become a net-exporter. The electricity imports to the Netherlands will decrease due to the rapid decentralization of electricity supply and, also, through capacity expansion from gas turbine combined-cycle power plants. Italy will remain the region with the largest import share covering domestic electricity demand, but this share will be more than halved during the simulation period due to assembling own generation facilities. The Iberian Peninsula keeps its position as an net-importing region, while Great Britain, in contradiction to the present situation, would become a net-exporter due to the reallocation of power flows within Europe.

Comparing the electricity imports arising in the unrestricted-trade scenario with the import limits implicit in the European Commission's Internal Market directive (approximately 23% in 1999 and 33% in 2005), it can be seen from figure 3 that the import shares stay well below those limits. Only for Italy the import share in 2000 is above the limit for 1999, but not above the limit for 2005.

Interregional power trade in Europe

Tables 8, 9, and 10 show the development of bilateral power trade for the observed regions during 2000, 2010, and 2020. It also can be seen too that in the long term Germany, the Alp-region and Great Britain increase their net imports, while Benelux becomes a net exporting region. In Italy one observes a strong reduction in imports. To achieve the power flows, additional transmission capacities are necessary. Between France and the Alp-region an additional 2000 MW connection has to come into operation. Also the connections between Germany, France and Benelux must be upgraded by approximately the same magnitude.

Table 8: Inter-regional electricity trade in 2000 [TWh/a]
("Internal Market")

Export	Import								
	GE	FR	A / SUI	Benelux	IB	GB	IT	Scand.	East-E.
GE	0.0	0.2	18.6	6.5	0.0	0.0	0.0	3.1	4.8
FR	15.9	0.0	23.2	7.7	11.6	6.7	68.0	0.0	0.0
A / SUI	9.1	0.6	0.0	0.0	0.0	0.0	43.7	0.0	0.7
Benelux	8.2	1.3	0.0	0.0	0.0	0.0	0.0	3.4	0.0
IB	0.0	0.5	0.0	0.0	0.0				
GB	0.0	9.3	0.0	0.0	0.0				
IT	0.0	0.1	0.0	0.0	0.0				
Scand.	6.5	0.0	0.0	1.7	0.0				
East-E.	2.7	0.0	5.4	0.0	0.0				

Source: own calculations.

Table 9: Inter-regional electricity trade in 2010 [TWh/a]
("Internal Market")

Export	Import GE	FR	A / SUI	Benelux	IB	GB	IT	Scand.	East-E.
GE	0.0	0.2	13.0	6.2	0.0	0.0	0.0	6.1	7.0
FR	27.5	0.0	25.2	6.2	18.4	7.7	50.0	0.0	0.0
A / SUI	6.2	0.5	0.0	0.0	0.0	0.0	19.7	0.0	0.8
Benelux	16.4	1.4	0.0	0.0	0.0	0.0	0.0	3.4	0.0
IB	0.0	0.4	0.0	0.0	0.0				
GB	0.0	5.3	0.0	0.0	0.0				
IT	0.0	0.1	1.5	0.0	0.0				
Scand.	10.0	0.0	0.0	1.7	0.0				
East-E.	3.0	0.0	7.4	0.0	0.0				

Source: own calculations.

Table 10: Inter-regional electricity trade in 2020 [TWh/a]
("Internal Market")

Export	Import GE	FR	A / SUI	Benelux	IB	GB	IT	Scand.	East-E.
GE	0.0	0.2	9.3	7.1	0.0	0.0	0.0	6.1	8.6
FR	23.9	0.0	22.5	5.0	9.7	9.3	35.5	0.0	0.0
A / SUI	12.9	0.6	0.0	0.0	0.0	0.0	15.5	0.0	0.9
Benelux	21.7	2.1	0.0	0.0	0.0	0.0	0.0	3.3	0.0
IB	0.0	0.6	0.0	0.0	0.0				
GB	0.0	5.6	0.0	0.0	0.0				
IT	0.0	0.1	1.2	0.0	0.0				
Scand.	10.1	0.0	0.0	1.8	0.0				
East-E.	3.2	0.0	7.5	0.0	0.0				

Source: own calculations.

Effects on Power Generation and Total Capacities

The effect upon the European electricity industry of creating an internal electricity market, in terms of percentage changes from the ‘closed market’ case, is presented in table 11. Obviously, there is a substantial reallocation of total power generation to the various countries. In comparison with the ‘closed market’ case, power generation decreases in Germany, Italy, the Alp-region and Spain/Portugal, and increases in France, the U.K. and Benelux. The increase in France and the U.K. is more pronounced in the intermediate term (2005) than in the long term (2020), whereas the increase in Benelux the reverse is true. On the other hand, the reduction in German electricity generation is substantially stronger in the long term than in the intermediate term, whereas the opposite is true for the reduction in Italy and Spain/Portugal.

Table 11: Change in Total Generation [%]
(„Internal Market" vs. „Status Quo")

	2000	2005	2010	2015	2020
GE	-0.23	-0.74	-4.37	-6.70	-7.04
FR	11.01	9.20	9.36	5.65	2.81
GB	4.67	3.69	3.03	2.81	1.65
IT	-28.80	-18.02	-7.99	-6.82	-2.96
BNL	3.16	5.06	8.76	14.77	14.32
A/SUI	4.28	-8.41	-16.32	-6.01	0.83
IB	-3.42	-2.45	-4.90	-1.89	-0.82

With respect to capacities, there is an intermediate term reduction in Italy, the Alp-region, and on the Iberian Peninsula, but this reduction is most pronounced in Italy (table 12). In the long term, the effect on Italian and Iberian capacities tends to fade out (due to the convergence of capital costs). Only in Belgium/Netherlands can one observe a permanent and significant increase in capacity. It is remarkable that the increase in French and British power generation continues with very little additional or less capacity, indicating more intensive utilization of existing capacities.

Table 12: Change in Total Capacities [%]
(„Internal Market" vs. „Status Quo")

	2000	2005	2010	2015	2020
GE	0.73	0.71	-0.98	-3.77	-6.05
FR	0.02	2.27	2.22	0.00	0.88
GB	0.00	0.00	-0.10	-0.10	-1.65
IT	-14.78	-6.59	-0.88	-2.10	-1.03
BNL	9.83	4.87	8.33	16.53	8.58
A/SUI	1.43	-3.26	-8.98	-2.06	6.79
IB	-2.82	-1.41	-1.56	-1.06	-0.32

Development of the power plant structure

The power plant structure covering the base load in most regions is determined by geographical or politically-set factors for hydroelectric, nuclear and lignite-based power plants. Therefore, additional electricity demand has to be covered from electricity imports or natural gas and hard coal fired power plants. With increasing electricity demand it will become unavoidable (ceteris paribus) that these power plant types must also cover the base load. With respect to the assumed increase in the discount rate (from 5% real to 8% real), GTCC power plants are expected to increase in importance.

Table 13: Absolute Change in Capacities by Energy Carrier in Europe [GW]
(„Internal Market" vs. „Status Quo")

	2000	2005	2010	2015	2020
Hard Coal	-4.70	-5.90	-6.00	-16.90	-34.60
Lignite	0.60	0.60	0.60	-2.90	-1.60
Oil	0.00	3.70	0.30	0.30	0.00
Gas	-3.40	-1.90	5.30	19.90	35.00
Nuclear	0.00	1.80	-0.40	-1.00	0.00
All Thermal	-7.50	-1.70	-0.10	-0.60	-1.20

By the turn of the century, capacity of hard coal and gas-based power plants will decrease based on age-structure-related decommissioning, and they will be not replaced. New capacity will not be installed due to the over-capacity in most regions and the better utilization of existing power plants. Necessary additional capacity for the base and middle load after 2005 will be obtained mainly through gas-combined-cycle power plants. Natural gas-based power plants with combined-cycle enjoy high efficiency rates and relatively low investment costs. Gas turbine combined-cycle technology can also be employed to cover the base load with a higher efficiency and relatively minimal emissions. In all regions additional capacity of this plant type will be installed. Especially in regions with relatively low gas prices, which substitute for reduced hard coal capacities. Minimal growth for natural gas-fired plants arises due to additional capacity coverage from gas turbines. The slight reduction of lignite power plants after 2010 concerns mainly Germany and is caused by the reduced competitiveness of these capital intensive power plants, when the relative importance of capital cost increases.

5 Conclusions

Interregional dynamic optimization models are powerful instruments for analyzing economic and environmental problems in the electricity sector. A major advantage is based on the detailed description of the production processes. A disadvantage is the partial analytical perspective of these models. One possibility to overcome this problem, is to combine the electricity model with a sectoral disaggregated macroeconomic model. This is desired in order to endogenize power demand and input factor markets.

The computations described in this article highlight the aspects of an integrated market for electricity. In the near future, the integrated electricity market will have a significant influence on national energy policies in Europe. Especially in the electricity sector national policies will have to take into account the increased international complexity.

The computations lead to the following conclusions: Over time the opening of national electricity markets in Europe leads to a reallocation of power generation in the various regions and to a change in the fuel mix. As a result of market opening, power generation is especially relocated from Germany and France to Italy and Belgium/Netherlands. A relocation of power generation to countries with a high share of nuclear power or access to natural gas can be found. GTCC power plants will gain importance due to their comparatively low capital cost. In evaluating these simulations it must be noted that the precise numerical results depend, of course, on the assumptions made (especially with respect to cost convergence).

The import shares arising from a scenario of unrestricted electricity trade stay well below the limits implied by the European Commission’s Internal Market directive. They do not necessarily increase over time, because competitive pressures present in the Internal Market lead to a partial convergence of costs, thus reducing the incentives for trade.

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Appendix[1]

1. Power Generation by Fuel Type [TWh]:

A 1 Germany:

	1994 (act)	2000	2005	2010	2015	2020
Hard Coal	108	131	135	103	105	64
Lignite	124	138	146	151	138	164
Oil	4	3	3	0	0	0
Gas	20	12	19	58	83	110
Nuclear	142	147	147	145	140	147
Hydro	20	21	22	23	24	25
All	418	453	472	480	490	510

A 2 France:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	21	21	77	73	68	74
Oil	4	4	4	5	0	0
Gas	3	3	1	3	27	15
Nuclear	342	342	406	435	459	484
Hydro	81	81	74	74	76	77
All	450	450	562	590	630	649

A 3 Great Britain:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	158	116	132	168	199	203
Oil	12	6	5	4	2	3
Gas	46	137	147	126	116	133
Nuclear	80	93	93	98	98	98
Hydro	6	6	6	7	7	7
All	302	358	384	402	421	443

A 4 Italy:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	18	79	84	80	79	108
Oil	109	16	16	13	5	5
Gas	38	27	73	125	162	162
Nuclear	0	0	0	0	0	0
Hydro	47	51	51	52	54	55
All	213	173	223	270	300	330

[1] All number refer to the internal market szenario.

A 5 Benelux:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	41	68	57	55	53	44
Oil	1	1	1	1	1	1
Gas	52	36	61	75	92	111
Nuclear	43	45	45	49	49	49
Hydro	2	2	2	2	2	2
All	139	153	166	183	197	207

A 6 Alp-Region:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	3	6	5	1	1	2
Lignite	1	2	2	0	1	2
Oil	2	1	1	1	1	1
Gas	8	7	1	1	5	15
Nuclear	23	22	22	20	22	22
Hydro	76	79	79	83	86	89
All	113	116	110	105	116	131

A 7 Iberian Peninsula:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	57	65	66	58	74	82
Lignite	11	13	13	11	17	18
Oil	6	7	6	3	2	4
Gas	0	9	40	68	80	100
Nuclear	53	53	53	59	59	58
Hydro	38	46	46	46	47	47
All	165	194	225	246	280	309

2. Installed Capacity [MW]:

A 8 Germany:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	24743	21711	22861	18618	15146	8929
Lignite	20305	19204	22084	23684	18540	22039
Oil	8404	5100	3060	1881	1647	1622
Gas	13823	9655	9370	15216	25050	29960
Nuclear	22563	21218	21218	20878	20219	21218
Hydro	8319	8607	8817	9171	9524	9878
All	98158	85495	87410	89447	90126	93646

A 9 France:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	10855	13000	11800	10600	10600	9490
Oil	8500	6750	5400	3445	3289	3335
Gas	1780	1189	1415	10319	14305	16705
Nuclear	58515	64290	68900	72800	76700	79300
Hydro	25355	24636	24636	25010	25384	25758
All	105005	109865	112151	122174	130278	134588

A 10 Great Britain:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	33189	30400	26800	23200	27546	28065
Oil	7438	7200	5760	4022	1728	3309
Gas	10722	25569	25484	30400	32200	34085
Nuclear	12019	12365	12365	13000	13000	13000
Hydro	4220	4342	4342	4526	4710	4895
All	67588	79876	74751	75148	79184	83354

A 11 Italy:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	8132	12540	12640	11840	11040	15059
Oil	21559	18150	17786	14786	7248	5678
Gas	13992	7534	14226	25186	35596	37570
Nuclear	0	0	0	0	0	0
Hydro	19745	19700	19700	20178	20656	21133
All	63428	57924	64352	71990	74540	79440

A 12 Benelux:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	7328	10255	8467	8275	7408	6161
Oil	1538	750	750	750	750	750
Gas	14892	13376	16622	21318	25868	28783
Nuclear	6033	6034	6034	6500	6500	6500
Hydro	2564	2505	2505	2505	2505	2505
All	32355	32920	34378	39348	43031	44699

A 13 Alp-Region:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	2043	2800	1600	1420	936	936
Lignite	560	343	343	343	322	315
Oil	1466	669	669	669	638	593
Gas	2193	2425	2690	2890	5511	8850
Nuclear	2944	2944	2944	2600	2990	2990
Hydro	22998	24116	24629	25337	26045	26753
All	32204	33297	32875	33259	36442	40437

A 14 Iberian Peninsula:

	1994 (act.)	2000	2005	2010	2015	2020
Hard Coal	9740	10589	11476	10718	10396	11456
Lignite	1800	1800	1800	1480	2310	2380
Oil	7928	8250	6885	3960	2808	4036
Gas	1241	3129	7329	12933	18588	21315
Nuclear	7000	7099	7099	7800	7800	7800
Hydro	20724	20937	20937	21277	21617	21958
All	48433	51804	55526	58168	63519	68945