Electrical Engineering 83 (2001) 265–270 © Springer-Verlag 2001

An integrated simulation model for European electricity and natural gas supply

C. C. von Weizsäcker, J. Perner

Contents This paper describes an empirical long-run simulation model for the European electricity and natural gas market. In a first step, electricity and gas markets are modelled separately by dynamic linear programming. In a second step, the models are linked by iteration. The model results show significant interrelationships between gas consumption in power generation and supply conditions on the gas market.

Key words Electricity and natural gas market model, Natural gas trading, Electric energy trading, Natural gas supply, Gas price forecast

Introduction

The deregulation of the European electricity and natural gas industry and the introduction of competition lead to rising interrelations between electricity and natural gas markets. The expected substantial construction of new gas-fired power plants in the coming years will induce a significant rise of natural gas consumption in western Europe. The European Commission [1] estimates that natural gas use in electricity generation will increase from 82.9 Mtoe in 1995 to 192 Mtoe in 2020 (+130%). On the other hand, rising gas demand should have an impact on gas prices. Gas prices directly influence the profitability of new power plant projects. As a consequence, the increasing scarcity of natural gas and the necessity to build new gas production and transport facilities could slow down the extension of gas-fired power generation.

The integrated simulation model for the European electricity and natural gas industry highlights the interrelations between gas usage in power generation, on one hand, and the supply conditions for natural gas in western Europe, on the other. The solution of the integrated model provides time paths until the year 2025 for natural gas prices and gas volumes consumed by the electricity supply industry. The electricity and gas markets are modelled by dynamic linear programming.

One of the first dynamic linear programming models of the electricity industry was developed by Rogers and Rowse [2] in 1988. The model simulates power generation, investments in power plants and the interregional electricity trade in Canada from 1990 to 2020. Hoster [3–5] took the concept of Rogers and Rowse and worked out a similar model for the European electricity market. For the gas industry, a first non-dynamic linear optimisation model was developed by Beltramo [6] et al. in 1984. The model simulates interregional gas flows and gas trade in the United States. On this basis, Boucher and Smeers [7] developed a corresponding model for Europe. A first dynamic model of European gas supply was introduced by Blitzer [8] in 1986. The model simulates interregional gas flows and simple investment decisions.

The models mentioned above and succeeding models either focus on the electricity or the natural gas industry. The link between electricity and gas markets has not been modelled before.

Mathematical structure of the model

In a first step, the European electricity and natural gas markets are modelled separately. In a second step, the models are integrated by iteration. For electricity the interregional, dynamic, linear programming model of the western European electricity market developed by Hoster [3, 4] in 1996 (EIREM) is used. A detailed description can be found in Hoster [3, 4]. For natural gas, a new sophisticated model of the European market is worked out.

The European Gas Supply Model (EUGAS) optimises natural gas production in the main producing regions in and around Europe, the transports from the production regions to Europe and inside the European gas grid, and gas supplies to end users. The model is dynamic since investments in production and transport infrastructure are endogenously optimised and facilities built in one time period can be used in following periods. Further on, the time path of natural gas extraction from the different gas reservoirs has to be optimised since resources are limited.

The model maximises total profits (TP) of all gas producers. Total profits are defined as the sum of discounted revenues (REV) over all time periods minus the aggregated and discounted capital costs (CC) and operating costs (OC) of natural gas production and transportation.

Objective (EUGAS)

$$\underset{\max}{TP} = \sum_{rtp} REV_{rtp} * \frac{1}{(1+ir)^{rtp}} - \sum_{dtp} CC_{dtp} * \frac{1}{(1+ir)^{dtp}} - \sum_{rtp} OC_{rtp} * \frac{1}{(1+ir)^{rtp}} \qquad (1)$$

Model time periods (rtp, dtp) are defined as periods of 5 years each. In order to avoid the end effect of the optimisation process [2] and to generate an accurate forecast

Received: 30 April 2001 / Accepted: 7 June 2001

C. C. von Weizsäcker, J. Perner (✉)
Energiewirtschaftliches Institut,
Universität Köln, Albertus-Magnus-Platz,
50923 Cologne, Germany

until 2025 (years 2025–2029), the optimisation period is extended until 2060.

Total profits are maximised subject to the following constraints (equations simplified in parts, indices partly skipped).

Balance equation
Demand (D) in the European consumption regions (c) and of the different market segments (m) equals aggregated gas supplies (S) of natural gas producers (sc):

$$D_{c,m,rtp} = \sum_{sc} S_{sc,c,m,rtp} \tag{2}$$

Supply constraints
Aggregated supplies of producers plus transportation losses (transports T multiplied with loss factor tl) from grid node i to j have to be lower than marketable gas production. Gas production (PM) in the main production regions (pr) is modelled in detail. Resource extraction and costs are specified on the basis of the vintage class or age of the used production facilities (atp) and the exploited reservoir class (r). Production losses are taken into account by loss factors (pl). Gas production in satellite regions (PS) enters the model without detailed resource and facility specifications:

$$\begin{aligned}\sum_{c,m} S_{sc,c,m,rtp} + \sum_{i,j}\left(T_{sc,i,j,rtp} * tl_{i,j}\right) &\le \sum_{pr\in pr(sc),r,atp\le rtp} PM_{pr,r,atp,rtp} * \left(1 - pl_{pr,r}\right)\\ &\quad + \sum_{pr\in pr(sc)} PS_{pr,rtp}\end{aligned} \tag{3}$$

Production capacity constraints (main production regions)
Production in main regions (PM) has to be lower than installed production capacities per reservoir class and region. Available production capacity is the sum of capacity installations (CAP) in the past minus decommissioned capacities (CDP). Past capacity installations include facilities built before the first optimisation period (exogenous capacities). Because of decreasing pressure in natural gas reservoirs, initial production capacities decline over time subject to specific decline rates expressed by cp:

$$PM_{pr,r,atp,rtp} \le \left(CAP_{pr,r,atp} - \sum_{rtp^*\le rtp} CDP_{pr,r,atp,rtp^*}\right) * cp_{pr,r,atp,rtp} \tag{4}$$

where as

$$\sum_{rtp} CDP_{pr,r,atp,rtp} \le CAP_{pr,r,atp}$$

Production constraints
Production in satellite regions is restricted by simple maximum quantities ($prcap$). Additionally, the aggregated annual production in main regions is bounded due to technical and political constraints:

$$PS_{pr,rtp} \le prcap_{pr,rtp} \tag{5}$$

$$\sum_{r,atp\le rtp} PM_{pr,r,atp,rtp} \le prcap_{pr,rtp} \tag{6}$$

Resource constraints
Production from reservoir class r is bounded by recoverable resources (RES):

$$\sum_{atp,rtp^*\le rtp} PM_{pr,r,atp,rtp^*} \le RES_{pr,r,rtp} \tag{7}$$

Capacity constraints in transport system
Transports from network node i to j are restricted by available transport capacity. Capacities can be used for gas flows in both directions. Available capacity is the sum of capacity additions in the past (CAT) minus decommissioned capacity (CDT). Capacity additions in the past include facilities built before the first optimisation period (exogenous capacities). Optionally, the construction of selected pipelines can be modelled as 0–1 decision (Mixed Integer Program):

$$\begin{aligned}\sum_{sc} T_{sc,i,j,rtp} &\le \sum_{atp\le rtp}\left(CAT_{i,j,atp} - \sum_{rtp^*\le rtp} CDT_{i,j,atp,rtp^*}\right)\\ &\quad + \sum_{atp\le rtp}\left(CAT_{j,i,atp} - \sum_{rtp^*\le rtp} CDT_{j,i,atp,rtp^*}\right)\end{aligned} \tag{8}$$

where as

$$\sum_{rtp} CDT_{i,j,atp,rtp} \le CAT_{i,j,atp}$$

Input-output constraints at transport nodes
Aggregated gas flows from grid node i to other nodes plus gas volumes distributed to end users in demand region c (DI) have to be lower than aggregated gas flows to the node plus marketable natural gas production at that node:

$$\begin{aligned}\sum_{j} T_{sc,i,j,rtp} + \sum_{c} DI_{sc,i,c,rtp} &\le \sum_{j^*}\left(T_{sc,j^*,i,rtp} * \left(1 - tl_{j^*,i}\right)\right) + \sum_{pr\in pr(sc),pr=i} PS_{pr,rtp}\\ &\quad + \sum_{pr\in pr(sc),pr=i}\ \sum_{\substack{r\\ atp\le rtp}} \left(PM_{pr,r,atp,rtp} * \left(1 - pl_{pr,r}\right)\right)\end{aligned} \tag{9}$$

where as

$$\sum_{m} S_{sc,c,m,rtp} \le \sum_{i} DI_{sc,i,c,rtp}$$

Long-term contract constraints (optional)
Gas volumes contracted in long term import contracts between producers and European import companies can

optionally be introduced to the model. Contracted gas volumes (*topmin*) enter the model as minimum supplies from producers to customer regions:

$$topmin_{sc,c,rtp} \leq \sum_m S_{sc,c,m,rtp} \tag{10}$$

Political constraints (optional)

Politics can implement thresholds on the purchase of natural gas from certain producers or production regions. In this case, producers' supplies are restricted by maximum market shares (*maxsup*). The constraint can optionally be introduced into the model:

$$\frac{\sum_m S_{sc,c,m,rtp}}{\sum_m D_{c,m,rtp}} * 100 \leq maxsup_{sc,c,rtp} \tag{11}$$

Decision variables of the linear program are volumes of natural gas production (*PM*, *PS*), capacity additions to production (*CAP*) and transport facilities (*CAT*), decommissioning of production (*CDP*) and transport (*CDT*) capacities, gas flows (*T*) and supply to European markets' respective market segments (*S*). (The variable *DI* is not relevant for the result of the optimisation and can therefore be skipped.) All other variables are state variables and depend on the decision variables.

The electricity market model EIREM is structured analogous to the natural gas supply model (EUGAS). The linear programming model optimises the construction and decommissioning of public power plants in western Europe as well as electricity generation in the installed capacities. Additionally, transmission capacities and power flows between the regions are optimised. The model generates forecasts until 2020, but the optimisation period is extended until 2050 in order to avoid the end effect. Simulation results are produced for periods of 5 years each.

Electricity generation is based on ten different types of plants. Annual electricity demand is subdivided into 12 load periods. The costs of the different generation technologies in combination with the load profiles are the main drivers for the decision which types of plants are extended.

The model minimises the aggregated and discounted costs of power generation and transmission over time in all regions of the model. Total costs comprise discounted operating costs (*TOC*), labour costs (*TLC*), maintenance and repair costs (*TMRC*), capacity costs (*TCC*), transmission costs (TTC), costs for power imports from satellite regions outside the core regions of western Europe (TIMC), and optionally environmental taxes (TAX).

Objective (EIREM)

$$\begin{aligned} \underset{\min}{TDC} = \sum_{t,reg} \Bigg(\frac{1}{(1+i)^t} * [&TOC_{t,reg} + TLC_{t,reg} + TMRC_{t,reg} \\ &+ TCC_{t,reg} + TIMC_{t,reg} + TAX_{t,reg}] \Bigg) \\ + \sum_t \Bigg(&\frac{1}{(1+i)^t} * TTC_t \Bigg) \end{aligned} \tag{12}$$

Total costs are minimised subject to the following constraints (for mathematical details see [3–5]).

Demand constraints

Exogenous demand has to be satisfied in all load periods.

Generation capacity constraints

Power generation is restricted by installed capacities.

Power production constraints

The availability of some fuels such as lignite or hydro power is restricted. Bounds can be due to technical or political reasons.

Transmission capacity constraints

Power transmission between the regions is bounded by installed and available transmission capacities.

The electricity model (EIREM) and the European gas supply model (EUGAS) are linked by iteration. In one step, the gas volumes used for power generation as a result of the EIREM run are included in the gas supply model as demand parameters. In the next step, natural gas prices calculated on the basis of the optimisation results of EUGAS are introduced in EIREM as fuel prices etc. (Fig. 1) With reasonable parameter assumptions, stable time paths for gas volumes used in power generation and natural gas prices can be achieved after 10–15 steps of iteration.

Empirical structure of the model and data entry

The gas supply model EUGAS comprises five main producing countries (Algeria, the Netherlands, Norway, Russia, UK) and six satellite production regions (Caspian, Egypt, Iran, Libya, Nigeria, Other Middle East, South America). Indigenous production in European countries not mentioned above enters the model as exogenous data. The main producing countries currently provide some 80% of the natural gas supplies to Europe. Main producing countries are subdivided into up to four sub-regions. The satellite production regions cover petroleum countries with increasing gas supply potential for Europe.

Gas resources, production facilities and costs of the main production regions are differentiated on the basis of the following criteria:

- Field size (three classes)
- Deposit depth (onshore: seven classes, offshore: two classes)

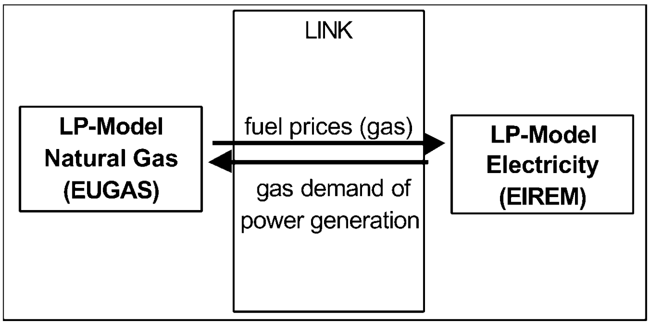

Fig. 1. Link between EUGAS and EIREM

– Water depth – offshore (three classes)
– Gas flow per well (three classes)

Production capacities built in the past are exogenously introduced to the model. Climatic conditions of the different production regions are taken into account in the calculation of production costs. Costs include investments, operating expenditures and optionally taxes and royalties. Public available information on resource classifications, installed production capacities and costs is rare, and therefore a wide range of data estimates is unavoidable.

Production costs in satellite regions are modelled as average costs. Produced volumes and costs are not differentiated within the regions.

The model distinguishes between ten European demand regions: Benelux, Germany, France, Iberian Peninsula, Italy/Switzerland, Central Europe, Poland, Southeastern Europe, Turkey. Production and demand regions are linked by pipeline or LNG connections. The transport network is modelled as a nodal system with hubs and spokes (Fig. 2). Transport capacities built in the past are taken into consideration.

The regional natural gas demand is attributed to consumption sectors: Households and other small consumption, industry, power generation. Total natural gas consumption will increase significantly during the next years. The rise in consumption in western Europe will mainly be due to a significant demand increase of gas-fired power generation.

The electricity market model EIREM consists of seven core and two satellite regions (Fig. 3). Electricity generation and power plants of the core regions are modelled in detail. Transmission and production capacities built in the past enter the model exogenously, capacity additions and decommissioning of the future are optimised endogenously. The satellite regions have an impact on electricity trade in Europe but are less important than core regions. Power transfers from core to satellite regions are exogenously given, imports to the core regions from the satellite regions are optimised on the basis of average production and transmission costs.

Exogenous electricity dmand is differentiated by core regions, time and load periods. Since the optimisation only covers electricity generation in public and centralised plants, power production in decentralised (e.g. CHP) or privately owned plants is subtracted from total demand (see the example of Germany in Table 2).

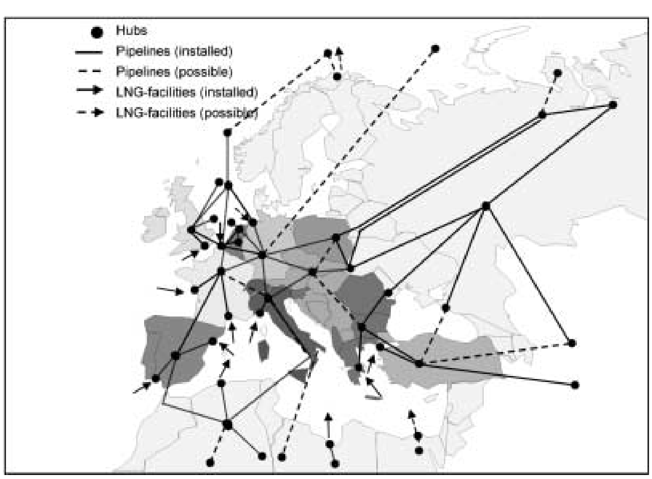

Fig. 2. Natural gas transport system in Europe

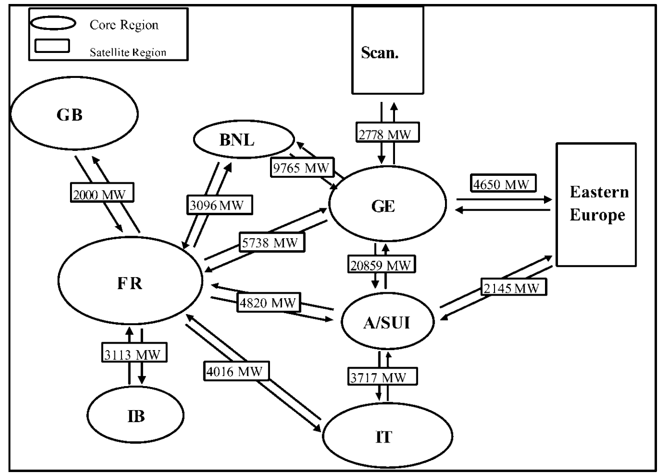

Fig. 3. European regions and transmission capacities in EIREM

Table 1. Natural gas demand in Europe

(Bill. m^3/year)	2000	2005	2010	2015	2020	2025
Benelux	57	68	61	62	64	64
Iberian Peninsula	21	31	37	42	48	48
France	39	48	53	60	67	67
United Kingdom	86	92	94	98	102	102
Germany	83	89	97	103	114	115
Italy/Switzerland	65	75	87	88	89	89
Central Europe	37	44	49	52	55	55
Poland	13	19	24	29	34	34
Southeastern Europe	25	32	38	43	49	49
Turkey	15	29	35	43	52	52

EIREM comprises ten types of plants. Fuel prices are regionally differentiated. The price of natural gas is replaced by prices generated by the gas model (EUGAS) during the iteration process. The price of lignite does not include sunk costs of the mines, and therefore prices are low enough to enable existing lignite power plants to produce electricity economically. Nuclear power will be phased out in Germany after the economic lifetime of installed capacities (Table 3).

Exemplary model results

The model is solved on PC. The used computer software is GAMS 2.25 [9]. The model results for the natural gas

Table 2. Electricity demand in Germany

Germany (TWh per year)	1995	2000	2005	2010	2015	2020
Total electricity demand	501	522	541	561	573	580
Decentralised/private power gen.	99	111	130	152	170	191
Electricity demand of the model	403	412	411	409	403	389

Table 3. Fuel prices in Germany

Germany (DM per GJ)	1995	2000	2005	2010	2015	2020
Hard coal	2.94	2.94	2.94	2.97	2.97	3.00
Lignite	2.06	2.06	2.06	2.08	2.08	2.10
Oil	4.06	4.06	4.06	4.06	4.06	4.31
Natural gas*	5.44	5.44	5.44	5.75	6.42	6.42
Nuclear	0.94	0.94	0.81	0.69	0.69	0.69

*replaced by iteration

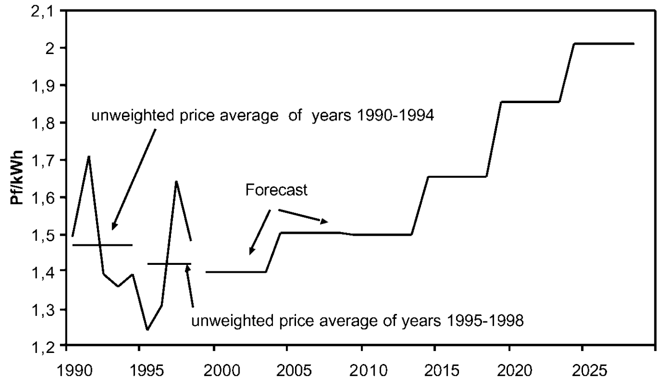

Fig. 4. Gas import prices in Germany: values in the past and forecast

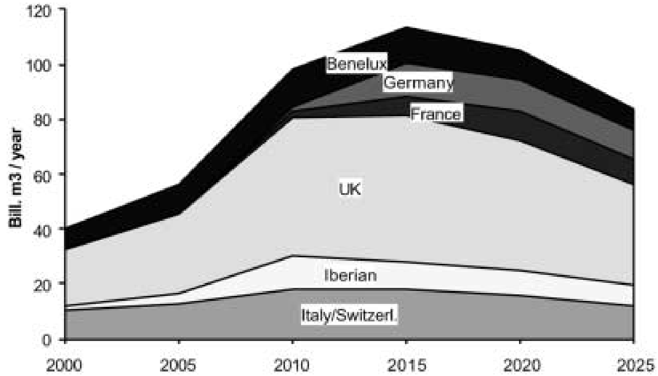

Fig. 5. Natural gas consumption of power generation in western Europe

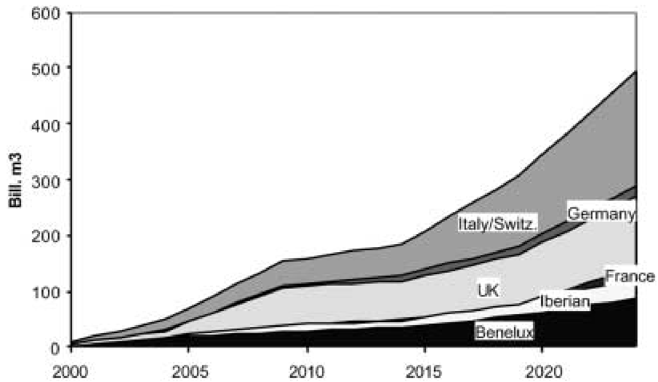

Fig. 6. Additional gas demand of power generation in low-cost scenario

industry are: gas production, transport flows, construction and decommissioning of production and transport infrastructure, gas supplies; for electricity industry: power generation, power transmission, construction and decommissioning of generation and transmission facilities.

Concerning the interrelation between European natural gas and electricity markets, natural gas prices for power generation are of special interest. Gas prices have an impact on the competitive position of gas-fired power generation in relation to other fuel types and therefore have an impact on the construction of new gas-fired power plants. Natural gas prices of the model are calculated on the basis of long-term marginal costs of natural gas supply to Europe. The pricing concept assumes that the current practice of net-back-pricing is abolished and cost-based pricing is introduced because of increasing competition between producers.

In the base-run, gas resources of the producing countries and the costs of gas production and transport are estimated on the basis of public available data. Assumed cost reductions induced by technological progress are very low (lower than 1% per year). The model results show a moderate hike in natural gas prices between 2005 and 2014 and steadily increasing prices after 2015 (Fig. 4). The prices until 2014 are in the range of the prices in the past (before 1998). The model results lead to the conclusion that supply volumes from low-cost natural gas sources are sufficient until the middle of the next decade, and thereafter more cost-intensive sources have to be developed.

The western European natural gas consumption of power generation extracted from the simulation results of the electricity market model increases significantly over the forecast periods (Fig. 5).

Natural gas flows in Europe also increase during the forecast period (Fig. 5). Nevertheless, gas deliveries estimated on the basis of existing gas import contracts are higher than physical flows of the model. The difference between supply volumes in import contracts and physical gas flows are in parts due to gas swaps: Gas suppliers from different regions can exchange gas volumes in order to minimise transport flows and costs. In economic terms, the supplier with the supply contract delivers the gas to the importer, in physical terms the importer is supplied by the source with minimal transport costs.

The long-term feedback between natural gas and electricity markets can be studied, for example, when reducing assumed costs for natural gas production and transportation. A reduction of 20% of the assumed costs in the natural gas business compared to the base-run lead to a rise in cumulated natural gas consumption in power generation until 2025 in the range of ca. 24% (Fig. 6). Gas prices are only between 2% and 18% lower than in the base-run. It can be concluded that the balance between gas supply and consumption is achieved more by shifts in volumes than in prices: The heavily increasing gas demand of the power sector induces rising gas prices being similar to prices in the base-run in some periods.

References

1. European Commission (1999) European energy outlook to 2020. European Communities, Brussels
2. **Rogers JS**, **Rowse JG** (1989) Canadian interregional electricity trade. Energy Economics April: 105–118
3. **Hoster F** (1996) Auswirkungen des europäischen Binnenmarktes für Energie auf die deutsche Elektrizitätswirtschaft, Schriften des Energiewirtschaftlichen Instituts, vol 51. Oldenbourg, Vienna
4. **Hoster F** (1996) Auswirkungen des europäischen Binnenmarktes für Energie auf Stromhandel und Erzeugungsstruktur – Resultate eines Simulationsmodells des europäischen Kraftwerksparks. ZfE 4/96: 303–318
5. **Hoster F**, **Welsch H**, **Böhringer C** (1997) CO_2 Abatement and Economic structural change in the European internal market. Springer, Berlin Heidelberg New York
6. **Beltramo MA**, **Manne JP**, **Weyant JP** (1986) A North American gas trade model (GTM). Energy Journal 7: 3: 15–32
7. **Boucher J**, **Smeers Y** (1985) Gas trade in the European Community during the 1970s. Energy Economics April: 102–116
8. **Blitzer CR** (1986) Western European natural gas trade model, MIT EL 86-010. Western Europe Natural Gas Trade, Final Report, pp 5-1-5-34
9. **Brooke A**, **Kendrick D**, **Meeraus A** (1992) GAMS, release 2.25, a user's guide. Scientific, San Francisco