INTERFUEL SUBSTITUTION IN OECD-EUROPEAN ELECTRICITY PRODUCTION

BY ERLING MOXNES
CENTRE FOR PETROLEUM ECONOMICS
CHR.MICHELSEN INSTITUTE
FANTOFTVN.38 - N-5036 FANTOFT - NORWAY

ABSTRACT

A DYNAMIC SIMULATION MODEL OF INTERFUEL SUBSTITUTION IN OECD-EUROPEAN ELECTRICITY PRODUCTION IS PRESENTED. A COMBINATION OF A PRIORI INFORMATION AND A CALIBRATION OF THE MODEL TO HICTORICAL DEVELOPMENT PRODUCES SEVERAL IMPORTANT RESULTS. ADJUSTMENT TIMES ARE MUCH LONGER THAN USUALLY ASSUMED, AND PRICE ELASTICITIES ARE MUCH HIGHER. BOTH THE SIMULATION MODEL AND ECONOMETRIC ESTIMATES INDICATE THAT THE LOGIT MODEL IS A BETTER REPRESENTATION OF FUEL CHOICE IN THE SECTOR THAN A CONSTANT ELASTICITY FUNCTION. THE LOGIT MODEL EXPLAINS WHY ESTIMATES OF PRICE ELASTICITIES TEND TO VARY OVER TIME. IT ALSO INDICATES THAT A FUEL CAN PRICE ITSELF COMPLETELY OUT OF THE MARKET. FINALLY, THE RESULTS INDICATE THAT COAL IS PROTECTED EQUIVALENT TO A PRICE SUBSIDY OF ABOUT 36 PERCENT.

1_INTRODUCTION

The potential for interfuel substitution in electricity production is clearly very large since electricity can be produced by any of the primary fuels oil, gas and coal. (We disregard hydro electric and nuclear power in this paper). Which of these three fuels electricity producers will choose, depends on the relative costs of the alternatives. Since different producers in different countries face different costs, there is a certain probability that all fuels will be chosen to varying extents. One purpose of this paper is to investigate how much of the different fuels are chosen for different underlying costs.

The short-term potential for substitution is limited by long life-times of power plants and high costs of converting a plant from using one fuel to using another. On the other hand, econometric estimates of the adjustment times are typically surprisingly short. Thus, a second purpose of this paper is to investigate whether the adjustment times are dominated by life-times of about 30 years or whether they are in line with the econometric estimates of about 8 years.

For both purposes, a simulation model of interfuel substitution is developed. Using a priori data about the costs of the different fuel options, variations in these costs among different power plants, life-times of equipment, and the extent of short-term flexibility in electricity production, the simulation model replicates historical development in OECD-Europe since 1960 amazingly well. However, to get a good fit, it is necessary to assume that the use of coal in power plants is subsidized or encouraged by other means.

Our model indicates that in the long-term all fuels can be substituted by each other. Considerable differences in average costs of the different options are needed to rule out a fuel completely. The model also indicates that the adjustment process is dominated by the long life-times of plants. Probably less 30 percent of production is flexible in the short run.

The econometric estimates seem to be erronously dominated by the short-term dynamics of the flexible capacity. An estimate on synthetic time-series produced by the simulation model gives approximately the same short adjustment times as the estimates on the real historical data. Thus, the controversy between dominating life-times in the simulation model and short adjustment-times in econometric estimates seems to be explained by estimation biases in the latter.

In section 2 the simulation model is explained. In section 3 data for electricity generation in OECD-Europe is presented. Section 4 shows model simulations over the historical period. In section 5 econometric estimates are reported, and section 6 contains the conclusions. All prices are in 1983 USD.

2 A SIMULATION MODEL OF INTERFUEL SUBSTITUTION

Our model of interfuel substitution involves the following five steps:

- determining fuel shares in power plant investments
- keeping track of vintages of power plants
- determining total investments in power plants
- determining capacity utilization of power plants
- determining the utilization of flexible capacity

The purpose of this section is to present these five steps.

2.1 Determining Fuel Shares in Power Plant Investments

Figure 1 illustrates how the share of gas in new power plants depends on the total costs of the gas option. For the individual plant the choice is typically one or another of the options. The model assumes that the individual producer chooses the cheapest alternative. This is illustrated by the straight lines in figure 1. When the total costs for gas are below the costs of the alternatives, gas is chosen. When the total costs of gas are not the lowest, another fuel is chosen.

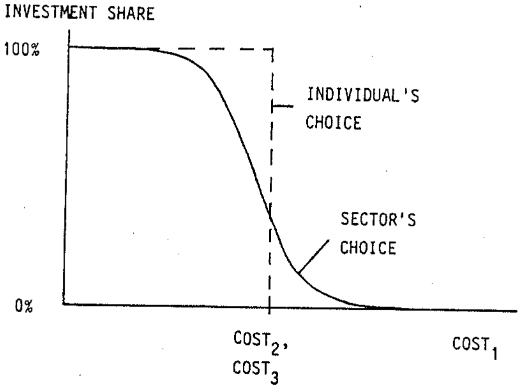

Figure 1: Illustration of the share of gas in new power plants as a function of the costs of using gas.

Total costs, C_i, of a fuel option is given by the formulae:

$$C_i = CC_i/PBT + OO_i + FP_i/E_i - P_i \tag{2.1}$$

CC_i is capital costs, PBT, is required payback time, OO_i, is other operating costs than fuel costs, FP_i, is the fuel price, E_i, is the burner efficiency, and, P_i, is a positive or negative premium. This premium reflects properties like domestic employment opportunities, cleanliness, flexibility and availability. In case P_i is calibrated to make the model fit historical behaviour, P_i will also reflect statistical errors in other parameters and deficiencies of the model.

All cost elements in equation 2.1 vary from plant to plant. Capital costs vary due to different requirements at different sites, and because a multitude of equipment suppliers offer different prices. Burner efficiencies, other operating costs, payback time requirements and premiums vary similarly. Fuel prices vary between fuel qualities and between countries. Different tax regimes and regulations explain much of the latter variation.

The fact that different users face different total costs, implies that the sum of users behave differently than the individual user. All users will not suddenly shift from one particular fuel to another when the average total costs of one fuel increases slightly above the costs of another. Some of the users will still find the first fuel to be the cheapest alternative. The smooth and curved line in figure 1 shows how the market share is gradually lost as the average total cost of gas increases. This is a less rigid view of the substitution process than the often voiced assertion that a fuel is either competitive or not competitive.

The following equation is assumed to determine the planned fuel shares, PS_i:

$$PS_i = e^{-aC_i} / \sum_j e^{-aC_j} \qquad (2.2)$$

As before, C_i is the average total costs of each fuel, and, a, is a constant reflecting the variation in costs between the individual users. The model in equation 2.2. is a so-called logit model, see for example McFadden(1976). It gives a shift in market shares as shown in figure 1, and it has the nice property that the sum of market shares always add up to 1. Since the sector for electricity generation produces only one product, electricity, the sector is homogenous and ideal for the use of logit function.

$$\dot{S}_i = (PS_i - S_i) / CT \qquad (2.3)$$

The actual fuel share in new plants is given as a lagged version the planned fuel share, see Equation 2.3. The average delay time, CT, reflects the construction time of new power stations. This means that we assume that the fuel choice cannot be changed after construction has started.

Total investments, I_i, in power plants using fuel, i, are given by the product of fuel share, S_i, and total investments, I.

$$I_i = S_i * I \tag{2.4}$$

2.2 Keeping Track of Vintages of Power Plants

When users have invested in new power plants, these will usually burn the same type of fuel for their whole lifetime. This is because rebuilding or premature replacement is costly and cumbersome. For example, Chessire&Robson(1983,figure 9) show that no premature replacements of gas or oil fired boilers with coal fired boilers in industry have a payback time of less than four years. This is for a price differential of 9 pence/Therm between oil/gas and coal, which is about the difference between heavy fuel oil and coal in 1981 (figure 7). We suspect that the payback times are somewhat lower for large power plant boilers than for industrial boilers. For higher price differentials, and for flexible power plants that are designed to use several fuel inputs (dual or multi-firing capacity), a shift between fuels can occur during the lifetime of the plant. This should be kept in mind when using the model with extreme price assumptions. We return to the question of multi-firing capacity later.

With the above simplifying assumptions, the dynamics of the model become fairly simple. Two vintages of capital, new power plants, KN_i, and old power plants, KO_i, are kept track of. Investments, I_i, increase the stock of new power plants; aging of new power plants, DN_i, redefine new into old power plants after half the lifetime of the power plants, T_i. DO_i, is the scrapping of old power plants. Note that capital is defined in units of capacity to burn fuels (Mtoe/year).

$$\dot{KN}_i = I_i - DN_i \tag{2.5}$$

$$\dot{KO}_i = DN_i - DO_i \tag{2.6}$$

$$DN_i = KN_i/(T_i/2) \tag{2.7}$$

$$DO_i = KO_i/(T_i/2) \tag{2.8}$$

Aging of new and old power plants is proportional to the number of power plants in each category. This means that a fairly wide distribution of lifetimes is implicit. Using two vintages ensures that no power plants are depreciated immediately after investment. Lack of more precise data about the lag structure is not terribly important since the behaviour of the model is relatively insensitive to the number of vintages.

2.3 Determining Total Investments in Power Plants

Since we have no data on investments in new capacity, capacity additions have been estimated from total energy demand in the sector. A simple way to do this is to let total yearly investments be equal to scrapping of old plants plus the difference between historical demand and simulated capacity in each year. However, this formulae has a weakness if demand drops rapidly, because investments might then become negative. In reality, rapid demand reductions are accomodated by reductions in capacity utilization or by premature scrapping. Investments will always be greater than zero, because some utilities will need to expand capacity even though the rest may have zero investments. This non-linearity is taken care of by the below expression for total investments in non-flexible capacity, I.

$$I = DO * f(\ (ED(1-FF)-K)/(TI*DO)\ ) \qquad (2.9)$$

ED is historical demand. FF, denotes the fraction of total demand that is met by flexible capacity, which is not considered by equation 2.9. K, is total simulated power plant capacity. The time to adjust investments, TI, determines how fast investments should adjust simulated capacity towards exogenous demand. DO is total scrapping of old power plants.

Figure 2 shows the exact shape of f(). When capacity equals demand, no adjustments are needed and investments equal scrapping of old plants, DO; f(0)=1. If demand falls below capacity, investments do not fall to zero. There will always be some new investments or replacements of old equipment going on. When demand is larger than capacity, the relationship allows for full adjustment of the power plant stock.

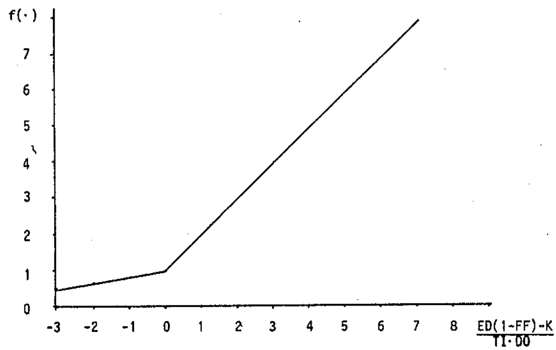

Figure 2: Form of the non-linearity in equation 2.9.

2.4 Determining Capactity Utilization of Power Plants

In order for the model to track exogenous energy demand in cases when demand drops more quickly than natural scrapping, the notion of capacity utilization is introduced. Capacity utilization for the non-flexible plants, U, is simply calculated as:

$$U = ED\ (1-FF)\ /\ K \tag{2.10}$$

If exogenous demand for non-flexible capacity, ED(1-FF), drops below simulated total non-flexible power plant capacity, K, utilization drops accordingly; capacity is not forced down. Thus, the model aims at maintaining a capacity that is sufficient to meet all peaks in demand. This is a much used method for estimating production capacity from production data.

Capacity utilization is assumed to be the same for all types of fuels in each sector. A possible relationship between capacity utilizaiton and the fraction of total energy demand that is flexible is not captured by the model.

Equation 2.11 shows the calculation of the demand for each fuel D_i.

$$D_i = K_i * U \tag{2.11}$$

2.5 Determining Utilization of Flexible Capacity

A certain percentage of all energy consuming equipment can use more than one fuel; the equipment has dual or multi-firing capacity. In addition some utilities or regions have several power plants using different fuels. These utilities can increase the load factor of the power plants with the cheapest fuels to the extent that the total power plant stock is under-utilized. This effect is called "power-wheeling". At off-peak hours, electricity is produced at the power stations with the lowest operating costs. Some of the flexibility can be utilized in a few minutes while other types of flexibility depend on rebuilding of equipment and expansions or reductions of inventories.

Fuel demand from flexible capacity, DF_i, is given by the total demand from flexible capacity, ED*FF, times the market share for each fuel, SF_i, as shown in Equation 2.12. ED, is total demand like in equation 2.9 and FF is the fraction of total demand that is met by flexible capacity.

$$DF_i = SF_i * ED * FF \tag{2.12}$$

The average adjustment time is taken care of by a lag formulation. The actual market share is given by the indicated market share, ISF_i, and the average adjustment time, TAF, as shown in Equation 2.13.

$$\dot{SF}_i = (ISF_i - SF_i)/TAF \tag{2.13}$$

Equation 2.14 shows how the indicated market share, ISF_i, is determined from the operating costs, O_i. Like for the investment share, a logit model is used to allocate total demand from flexible installations on the different fuels. The distribution, which is determined by a coefficient, b, is not as wide as for investment shares. This is because operating costs should be expected to vary less than operating costs plus capital costs.

$$ISF_i = (e^{-bO_i} / \sum_j e^{-bO_j}) \qquad (2.14)$$

The operating costs are determined by equation 2.15. The first term is fuel costs and the second term other operating costs like in equation 2.1. The third term, PF_i, denotes possible premiums attached to the different fuels.

$$O_i = FP_i/E_i + OO_i - PF_i \qquad (2.15)$$

3 DATA FOR ELECTRICITY GENERATION IN OECD-EUROPE

There are three main types of data used in the model for interfuel substitution. The main input is fuel prices. Then there are a number of other factors that influence market shares for the fuels. Finally, initial conditions are important for the early development of the model.

Figure 3 shows how fuel prices to the electricity generating sector have developed from 1960 to 1983. The OECD-European prices shown in the figure are calculate as an average of prices in France, Germany, Italy and the United Kingdom. These four countries made up 64 % of total OECD-European electricity consumption in 1980.

Price development can be divided into three phases. First is a period when oil and coal were equally expensive while gas was about twice as expensive. In the second period from 1968 to 1973 oil and gas had the same price while coal was about 50 percent more expensive. The third period is charachterized by quadrupling oil prices, more than tripling gas prices and a 50 percent increas in coal prices.

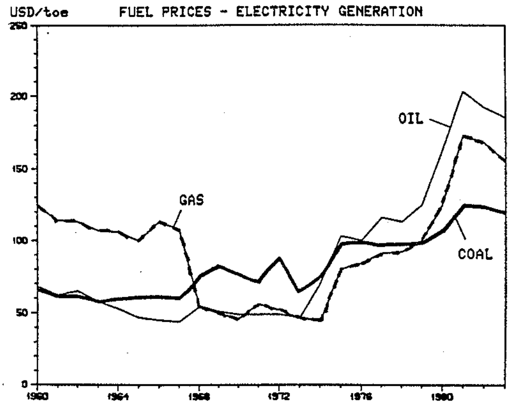

Figure 3: Real fuel prices for the electricity generating sector.
Source: Figure 3.3 in Moxnes(1985)

Table 1 summarizes the assumptions about costs, efficiencies, lifetimes and required payback periods made for the electricity generation sector.

Table 1: Costs, Efficiencies, Lifetimes and Payback Periods. Units are in USD/(toe electricity) unless otherwise stated.

	Year	Coal	Oil	Gas
Operating costs	1960	272	237	418
	1970	307	166	176
	1980	417	543	421
	1983	458	614	518
Fuel prices (USD/toe)	1960	66	68	124
	1970	76	46	49
	1980	108	163	125
	1983	120	185	155
Efficiencies (% electricity)	all	29	31	31
Other operating costs	all	45	18	18
Annualized capital costs	all	152	76	76
Capital costs(USD/(toe el.per year))	all	1520	760	760
Payback time(year)	all	10	10	10
Total costs	1960	425	313	494
	1970	459	242	252
	1980	570	620	497
	1983	611	690	594
Lifetime of plants,T (year)	all	30	30	30
Parameter for distribution,a (toe el./USD)	all	0.01	0.01	0.01
Parameter for distribution,b (toe el./USD)	all	0.015	0.015	0.015
Time to adjust total investments,TI (year)	all	3	3	3
Constr.time,CT (year)	all	6	6	6
Time to adjust flexible capacity,TAF(year)	all	2	2	2

Sources are mentioned in the text.

Operating costs are the sum of fuel costs (fuel prices divided by efficiencies) and other operating costs. Fuel prices come from Moxnes (1985) p.13. The fuel prices are defined according to IEA(1984). In this publication coal prices in Germany and in France only reflect prices of domestic coal. Since import prices are lower than domestic prices, the coal prices used are over-estimated. In Germany the prices are about 5 percent too high, in France about 17 percent too high, in 1982/1983. This means that the coal price for the entire OECD-Europe in 1982/1983 is about 3 percent too high when we know that Germany consumed about 30 percent of all coal in OECD-Europe and France about 6.3 percent.

Operating costs, capital costs and conversion efficiencies for coal have been taken from NEA(1983). Operating costs come from table 1 in the publication. The following conversion factors are used: 11700 kWh/toe, 0.924 USD/ECU (table 10), 1.23 1983 FF/1981 FF, 1.08 1983 DM/1981 DM, 1.33 1983 IL/1981 IL, 1.13 1983 PS/1981 PS. Capital costs also come from the same publication. Capital costs have been converted to USD/(toe electric per year) by the above conversion factors and by a payback time of 12.5 years, corresponding to a lifetime of 30 years and a discount rate of 5 percent. Both operating costs and capital costs reflect averages for the four major OECD-European countries. Fuel costs and conversion efficiency for coal are found by a combination of tables 1 and 6.

Lifetimes of coal fired stations vary between 25 and 40 years. Discount rates vary between 4 and 9 percent per year, see table 7 in NEA(1983). These numbers are used to set lifetimes and payback periods in the model. The construction time of coal fired stations is between 4 and 9 years, see table 7.

Table 2: Capital and operating costs of oil-fired power stations relative to corresponding costs of coal-fired stations.

Source	Capital costs (%)	Operating costs excl. fuel costs (%)
Abbey and Kolstad (fig.2)	40	40
Moxnes & Nesset, p. 34 (large industrial boilers)	50	(38 for gas)
IEA (1985), p. 195	74	84
WEC (1983), p. 185 (hypothesis)	83	95

For oil and gas-fired power stations we rely on sources that give costs relative to the costs of coal-fired power stations, see table 2. The variation of the estimates is quite large. For our purpose, this indicates that variations in capital costs and other operating costs contribute to a wider distribution of fuel choices. As a representative of the average costs we choose the numbers from IEA (1985).

Moxnes&Nesset(1985) show that oil and gas-fired industrial boilers are about 7 percent more efficient than coal fired boilers. We use this information as an indication to set the conversion efficiency correspondingly higher for oil and gas in power plants.

Table 1 shows that in 1983 gas and coal fired power stations had almost the same total costs. Higher fuel costs for gas were balanced by higher capital and other operating costs for coal. Oil was about 15 percent more expensive than gas due to higher fuel costs.

The coefficient for the distribution of investments, a, is set according to rough estimates of the variation in the different cost elements. The average variation in price differences for fossil fuels between the four major countries in OECD-Europe is USD70/toe. This implies a USD230/(toe electricity) variation in total costs because of generation efficiencies of about 30 percent. This is about 38 percent of the total costs of the fossil fuel alternatives in 1983.

Based on fuel price variation alone, a, should be set such that if two of the fuel alternatives have average costs of USD600/(toe electricity), the third alternative would not totally capture the market in all four countries unless the average costs of this alternative fell below USD370/(toe electricity). Because of price variations inside the individual countries, variations in capital costs, other operating costs, efficiencies and preferences, we set the distribution coefficient, a, to give only an 80 percent market share for a fuel with total costs of USD370/(toe electricity) when the two alternatives both cost USD600/(toe electricity).

The distribution of the fuel shares for the flexible part of power plant capacity is given by the coefficient, b. Since it is only operating costs and not operating costs plus capital costs that enter the logit function for flexible consumption, the distribution for flexible demand is more narrow than the distribution for capital dependent demand. The coefficient, b, is set relative to the coefficient, a, by judgement.

The time to adjust investments, TI, is set to maintain relatively smooth investments. The results are not sensitive to the exact choice of this parameter since the purpose of the model is to explain market shares and not total investments.

The fraction of the total fuel consumption that is flexible is set as follows: (The model interpolates between the data points)

	1960	1980	2000
Fraction flexible in electricity generation, FF:	0.2	0.3	0.4

One source we have seen estimates the total dual and multi-fired capacity in electricity generation in IEA-Europe to be about 30 percent of total thermal capacity in 1983. In addition the same source points to the potential for power wheeling, which depends on excess generation capacity and grid capacity. Since most of the flexible capacity is dual, we use a lower percentage for multi-fired capacity than 30 percent, and let power wheeling and possible rebuilding of equipment bring the percentage back up to 30 percent by 1980. Because of improvements in the grid for electricity transmission over time, we assume that the potential for flexibility increases linearly from 20 percent in 1960 to 40 percent in 2000. It seems that nuclear power stations are run at maximum capacity for base load production. Therefore they should not influence our estimates of flexibility.

The adjustment time for the flexible capacity is set equal to two years. This choice is an average of very quick adjustments of capacity utilization, adjustments that depend on depletion of fuel inventories, and adjustments that depend on minor adjustments or rebuilding of burners.

Initial conditions are obtained from time-series data for fuel consumption. Initial capacity to use the different fuels is set equal to consumption in the initial year. The split between new and old equipment, the vintages, is estimated only roughly by extrapolating fuel use trends backwards in time. Table 3 shows the initial capacities of new and old plants.

Table 3: Initial capacities of new and old power plants in 1960. Units are Mtoe/year.

	Coal	Oil	Gas
New plants	51.0(46.9)	9.0(4.3)	2.0(1.8)
Old plants	37.0(32.8)	3.0(-1.7)	0.0(-0.2)

When the model is run with a certain fraction of the power plants being flexible, the initial values of the inflexible power plant capacities in table 3 are reduced somewhat to maintain initial total capacity equal to historic demands. The minus signs are caused by a poor formulation of the equations for the initial conditions. However, the minus signs are of no practical importance; they could have been removed by redefining some new equipment to old.

4 SIMULATED AND HISTORICAL DEVELOPMENT OF FUEL DEMAND

The purpose of this section is to see how well the simulation model explains historical development, to estimate premiums for the individual fuels and to examine the importance of short-term flexibility.

First the simulation model is simulated without premiums ($P_i=0$) and without any short-term flexibility (FF=0). Figure 4 shows simulated and historical demands for coal, oil and gas.

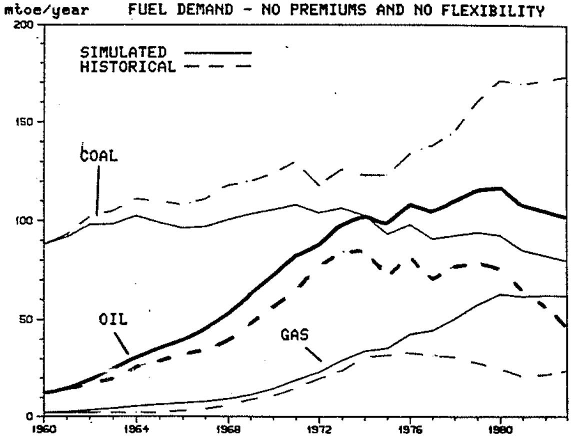

Figure 4: Historical and simulated development of the demand for coal, oil and gas; no premiums and no flexibility. Source for historical data: OECD Energy Balances.

Simulated fuel demand is clearly consistent with the fuel prices shown in figure 3. Oil, which has the lowest fuel, capital and operating costs until 1973, grows quickly during this period. Gas has a prohibitively high fuel price until 1967, and only captures a significant market share when the gas price drops to the oil price level in 1968. The coal option has higher fuel, capital and operating costs than oil until 1976 when the oil price rises more rapidly than the coal price. In spite of the higher costs, coal demand remains nearly constant during most of the period due to a growing demand for electric power and due to a fairly wide spread of fuel choices. Between 1976 and 1980, gas grows most rapidly because of lower fuel prices than oil and lower capital and operating costs than coal. After 1980 demand for all fuels stagnate due to stagnating total demand for electricity produced by fossil fuels.

Simulated behaviour is not well in line with historical development. Coal demand has nearly doubled since 1960, while the model predicts stagnation. Correspondingly, the model overestimates the demand for oil and gas. Assuming that the cost data we have used are fairly close to the historical costs, what could have caused the deviation between simulated and real development? The most likely explanation is an active protection of the European coal industry. Indigenous production of coal in OECD-Europe fell from 334 Mtoe/year in 1960 to 251 Mtoe/year in 1970, and it fell further to 224 Mtoe/year in 1983. Together with productivity improvements in the coal industry this development has meant continuous reductions in the employment of miners. This is clearly an incentive to protect indiginous coal production.

The main policy instrument has probably been a direct influence on the fuel choice in publicly owned power stations. In Germany, for example, the socalled hundertjahrvertrag is an overt protection of the domestic coal industry. The deviation between simulated and actual development indicates that direct and indirect subsidies to coal have been considerable. How large the "subsidies" have been, will be indicated by simulating the model with premiums. Figure 5 shows the simulation results, and table 4 shows the estimated premiums.

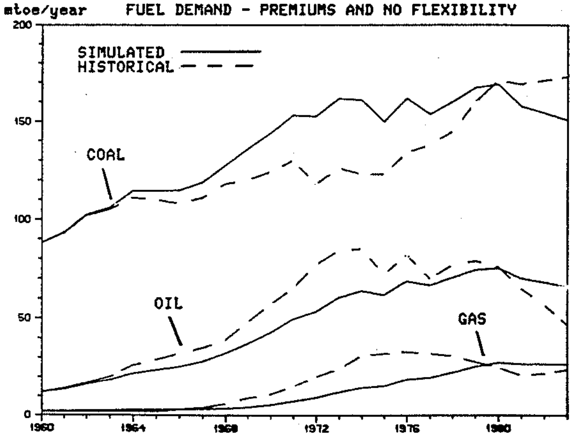

Figure 5: Historical and simulated development of the demand for coal, oil and gas; premiums and no flexibility. Source for historical data: OECD Energy Balances.

Table 4: Fuel premiums estimated by a rough calibration of the simulation model to historical data.

	Coal	Oil	Gas 1960	Gas 1970	Gas 1980
Premiums (USD/toe electricity)	150	0	-100	-50	-50
Corresponding to a percentage fuel price change of (%):	-36	0			+10

Note that since it is cost differences that determine fuel shares in the logit model, it is differences between premiums that are meaningful and not the absolute size of the premiums. We have chosen the premium on oil to be 0.

The premium on coal is considerable; it corresponds to a 36 percent price discount on the fuel price of coal. This is clearly much more than the likely 3 percent over-estimation of the coal price that we mentioned in the data section. The premium on coal reflects effective protection of coal. Since environmental effects should contribute to a negative premium on coal, the effect of protection for employment reasons might be even larger than what the above premium indicate.

The negative premium on gas corresponds to a 10 percent increase in the gas price in 1983. It might seem surprising that gas is discriminated more strongly than oil. An ad hoc explanation relates to the protection of coal. After 1973 the growth of oil stagnated, and oil was possibly viewed as a less dangerous competitor for coal than expanding gas supplies. The negative premium on gas in the 1960's is clearly explained by the lack of proven gas reserves and of an adequate distribution system. Restricted availability means that one of the assumptions underlying the logit model is violated. The premium makes up for this violation.

Although the premiums improve the fit between simulated and historical development, there is still considerable deviation. A further improvement of model behaviour is obtained by assuming that a certain fraction of total power plant capacity is flexible and can switch between the three different fuels. Figure 6 shows model development when this fraction is assumed to increase from 20 to 30 percent from 1960 to 1980. A negative premium on gas used for flexible capacity, is also assumed. The premium is set to -USD100/(toe electricity), corresponding to a price increase of 20 percent. This negative premium reflects the lack of distribution systems for gas. It also reflects that less widespread use of gas in power plants for base load purposes makes it less likely to find dual or multi-firing capacity using gas.

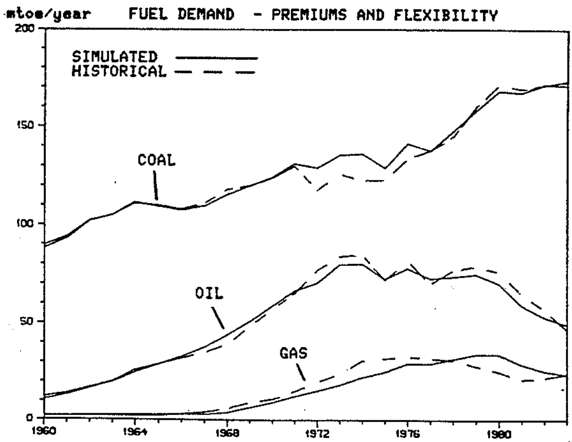

Figure 6: Historical and simulated development of the demand for coal, oil and gas; premiums and flexibility. Source for historical data: OECD Energy Balances.

To see more clearly what happens with respect to the utilization of the flexible capacity, figure 7 shows the flexible demands. The volumes are in direct correspondence with fuel prices in figure 3. The only distorting factors are minor differences between operating costs and power plant efficiencies for coal and for oil/gas and the imposed negative premium on gas.

Oil captures nearly all of the flexible part of the market towards the end of the 1960's. After price drops on gas in the late 1960's, gas becomes just as cheap as oil. However, the negative premium on gas implies a lower market share for gas than for oil. Coal loses the battle with oil in the 1960's and in the early 1970's because of high coal prices. However, after a rapid escalation of oil and gas prices in the late 1970's coal captures almost the whole flexible market.

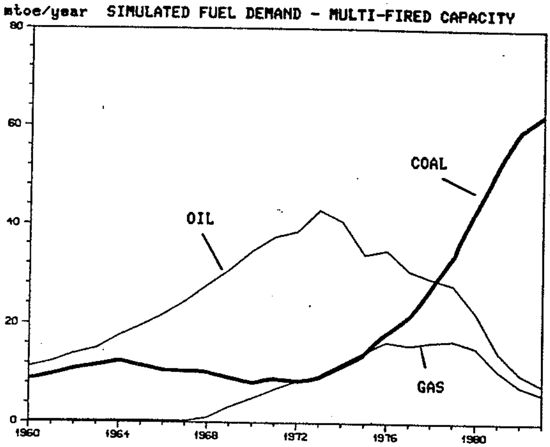

Figure 7: Simulated use of fuels in multi-firing capacity.

The behaviour of the simulation model is clearly consistent with historical behaviour. Thus the proposed model, based on a priori information, is not refuted by historical development. On the other hand, the good fit is not a proof that the model is the correct one. The good fit, together with the a priori information only works to build confidence in the model. Particularly, when it comes to the exact value of the parameters, uncertainty is quite large. Model behaviour is quite insensitive to changes in most of the a priori estimates of the parameters. Typically, calibration of the premiums will bring simulated behaviour quite near the historical development after a parameter change. Thus, the a priori estimates are very important for the overall quality of the model.

The model as it stands, does not allow for many additional explanations of development. For example, expectations about fuel price development does not seem to be needed as an explanatory variable. However, after the simulations have been made, one might wonder if the development of gas demand was influenced by expectations about future gas supplies. Large expansions of gas production were planned and announced years in advance in the early 1970's. Thus, it was possible to have correct expectations about gas availability and to prepare for the introduction of gas, see figure 6. However, this conclusion is probably rather weak; if the premiums are not calibrated to give the best possible fit, the room for additional explanations also increases.

5 ECONOMETRIC ANALYSIS OF FUEL DEMAND

Based on common results in econometric modeling of fuel demand, the results above are surprising in two respects. First, while the simulation model has an average adjustment time of about 20 years, econometric estimates typically yield adjustment times well below 10 years. Secondly, while econometric models most frequently assumes constant elasticities, the simulation model assumes that the price elasticities vary with fuel prices or market shares. The purpose of this section is to investigate this disagreement.

5.1 Adjustment time of fuel demand

We have not found econometric studies of the electricity generating sector in OECD-Europe. Thus, when we refer to low estimates of adjustment times, we think of typical estimates of adjustment times for aggregate energy demand and of fuel substitution; see results reported by Prosser(1985) and Kouris(1983). Therefore, to report econometric estimates of adjustment times in the electricity generating sector, we make our own estimates based on the historical time-series shown in figures 3 and 4. The following equation has been used:

$$D_{i,t} / E_t = A\, P_i^{b(1-k)}\, P_j^{c(1-k)}\, P_k^{d(1-k)}\, (D_{i,t-1} / E_{t-1})^k\, e_t$$

D_{it} denotes demand for fuel i in year t, and E_t denotes total demand for fossil fuels. Thus, the equation explains the market share for each fuel. In this way we do not complicate the estimation by introducing "income" elasticities. The market share depends on the fuel prices, P, elasticities, b, c, and d, the market share in the previous period, t-1, and the lag parameter, k. The Cobb-Douglas model ensures constant elasticities. The lag distribution follows the Koyck scheme. The model is frequently used and according to Kouris(1983), the Koyck spesification produces more plausible results than other dynamic spesifications. To estimate the parameter we use Ordinary Least Square estimation, which is also frequently used although it is likely to give biased estimates. The results are shown in table 5.

Table 5: Long-term price elasticities and lag coefficient estimated from historical data. * means that the parameter is significant at a 5 percent level. Adjustment time is calculated as 1/(1-k).

Demand for:	Effect of: Gas price b	Oil price c	Coal price d	Prev.Demand k	R-square:	Adjust. time:
Gas	-1.32	-2.95	+7.29 *	0.891 *	98.1	9.2
Oil	-0.18	-1.24 *	+1.22	0.852 *	97.4	6.8
Coal	+0.36	+0.68 *	-0.99 *	0.881 *	98.2	8.4

Only half of the long-term price elasticity estimates are significantly different from zero; two of the elasticities have the opposite sign of what should be expect.

The adjustment times vary between 6.8 and 9.2 years. Thus the estimated adjustment times are from two to three times shorter than the average adjustment time in the simulation model. The adjustment time in the simulation model is 20.6 years. This number is an average of the adjustment times for flexible and ordinary demand. Does this mean that the simulation model is not consistant with historical data after all? To investigate this question, we perform the same econometric testing on the output from the simulation model as we did on the historical data.

Table 6 shows that also the estimates made on the synthetic time-series yield adjustment times below 10 years, coal beeing an exception. Thus, it seems to be the econometric estimates that are biased. Several aspects are of importance for the bias.

Typically the sum of squares in the estimation routine is not very sensitive to proportional variations in price elasticities and adjustment times. A model with a high elasticity and a long adjustment time might give the same fit as a model with a low elasticity and a short adjustment time. Both models might fit the data perfectly and show good t-statistics. Therefore, the estimates of the adjustment times and the corresponding elasticities are likely to be strongly influences by random disturbances and spesification errors, see Moxnes1(1986).

Table 6: Long-term price elasticities and lag coefficient estimated from simulated data. * means that the parameter is significant at a 5 percent level. Adjustment time is calculated as 1/(1-k).

Demand for:	Effect of: Gas price	Oil price	Coal price	Prev.Demand	R-square:	Adjust. time:
Gas	-2.4 *	+0.3	+2.7 *	0.864 *	99.7	7.3
Oil	+0.1	-1.1 *	+0.0	0.884 *	99.8	8.6
Coal	+0.5 *	+1.1 *	-0.5	0.956 *	99.8	22.2

In our case spesification errors are the source of the bias since there are no random disturbances in the simulation model. The distribution of the lag structure in the simulation model is given by a first order delay for flexible capacity, an investment delay and two vintages for the ordinary capacity. This lag structure does not comply with the Koyck lag. As shown by Moxnes1(1986) the estimation procedure tends to put too much weight on the short-term dynamics of the real system with the result that the estimated adjustment times become too short. Moxnes1(1986) also shows that the logit formulation leads to estimation biases; however this bias might work both ways. A spesification error is also represented by a slight difference in the lag structure of the Koyck lag and the differential equation used to represent delays in the simulation model. The parameter estimates also depend on the exact development of the exogenous variables; this might explain why the adjustment time for coal is correctly estimated while the other two are much too low.

The above results have important implications for econometric estimates of long-term price elasticities in general. In our case both the estimated adjustment times and the estimated price elasticities should be multiplied by factors of two to three to get the adjustment times in line with the a priori estimates of the adjustment times, assuming that these are fairly well established.

5.2 Logit model instead of a constant elasticity function

The logit model shown in Equation 2.2 implies a price elasticity that is a function of fuel prices and market shares. The following equation gives a formulae for the own price elasticty in the logit model:

$$\text{Elasticity}_{ii} = a\ P_i\ (1 - S_i)$$

As the market share, S_i, approaches one, the elasticity approaches zero independent of the price, P_i. Conversely, when the market share approaches zero, the elasticity becomes very large since at this point the price will be high.

Is this relationship supported by the econometric estimates? According to the significant price elasticities in table 5, gas has the highest elasticities and coal has the lowest elasticities. Over the historic period we have examined, gas has had the lowest market shares and coal has had the highest. Thus, the econometric estimates in fact support the choice of the logit function.

6. CONCLUSION

The purpose of this paper has been to investigate substitution between oil, gas and coal in electricity production in OECD-Europe. To do so we have constructed a structural form model which gives a very good explanation of historical development. Consistency between a priori parameters and historical development serves to validate the model. The model explains why the implicit price elasticities vary over time; thus, what is often referred to as structural changes in the market is endogenous to the model. These features of the model make it well suited to make forecasts of energy demand, and to study policies for various actors in the energy market.

The most important features of the model are: the logit function which explains how the choice of fuel is distributed on oil, gas and coal as a function of costs; long life-times of power-plants; a considerable premium on coal; and the fraction of total capacity that is flexible with respect to short-term fuel choices.

We have estimated the average adjustment time to be about 20 years. This is in contrast to econometric estimates of about 8 years. However, we have found reasons to believe that the econometric estimates are biased downwards. Thus, we conclude that the econometric adjustment times should be multiplied by factors of between two and three; and very important, the corresponding estimates of price elasticities should be multiplied by the same factors. This means that the impacts of an oil price increase will last longer and and be stronger than what econometric estimates indicate.

The logit model gives a very good explanation of the fuel choice in both new power plant investments and in the utilization of flexible capacity. The logit model implies that a fuel can price itself completely out of the market, and that a fuel never can gain more than 100 percent of the market. However, a particular fuel will be chosen over a quite wide cost range since fuel prices and other cost elements vary quite a lot from plant to plant and from region to region. Econometric estimates also indicate that the logit model is a good choice.

Competition between oil, gas and coal is clearly influenced by governmental policies. Protection of coal is found to be equivalent to about a 36 percent price subsidy on coal. This protection is first of all explained by a continous reduction in the employment of miners in OECD-Europe over the last 25 years. The protection of coal in power plants is probably efficient because of public ownership or direct influence over investment decisions. A similar study of industrial fuel demand in OECD-Europe, indicates that there is very little protectión of coal in this sector, where direct influence is much more difficult, Moxnes2(1986).

7 REFERENCES

Abbey,David and Kolstad,Charles: The Structure of International Steam Coal Markets, Natural Resources Journal, Vol.23 Octobre 1983, no 4.

Chessire,John and Robson,Mike: UK Industrial Energy Demand: Economic and Technical Change in the Steam Boiler Stock. SPRU Occational Paper Series no.19. Univ. of Sussex, March 1983.

IEA(1984): Energy, Prices and Taxes, Second Quarter 1984, International Energy Agency, OECD, Paris 1984.

IEA (1985): Electricity in IEA Countries, International Energy Agency, OECD, Paris 1985.

Kouris, George: "Energy Demand Elasticities in Industrialized Countries: A Survey", The Energy Journal, Vol. 4, No.3, 1983.

McFadden,D: "Quantal Choice Analysis: A Survey" Annals of Economic and Social Measurement, 5/4, 1976.

Moxnes,Erling: Price of Oil, Gas, Coal and Electricity in four European Countries 1960-1983. CMI-no 852260-1, August 1985.

Moxnes,Erling and Nesset,Erik: Substitution between Oil, Gas, and Coal in U.K. Industrial Steam raising, CMI-no.842240-4, Bergen, Norway, March 1985.

Moxnes, Erling,1: "Underestimation of Long-Term Price Elasticities of Oil Demand", Proceedings of the 1986 International IAEE conference in Tokyo, or CMI-no.862260-3, June 1986.

Moxnes, Erling,2: "The Dynamics of Interfuel Substitution in the OECD-European Industrial Sector", forthcoming in Golombeck,R; Hoel,M.; Vislie,J.: Natural Gas Markets and Contracts, North Holland, 1986.

NEA,Nuclear Energy Agency: The Costs of Generating Electricity in Nuclear and Coal Fired Power Stations, A Report by an Expert Group, OECD,Paris,1983.

Prosser, Richard D.: "Demand elasticities in OECD, Dynamical aspects", Energy Economics, Jan.1985.

WEC: Oil Substitution, World Energy Conference, Conservation Commission, New Dehli, 1983.