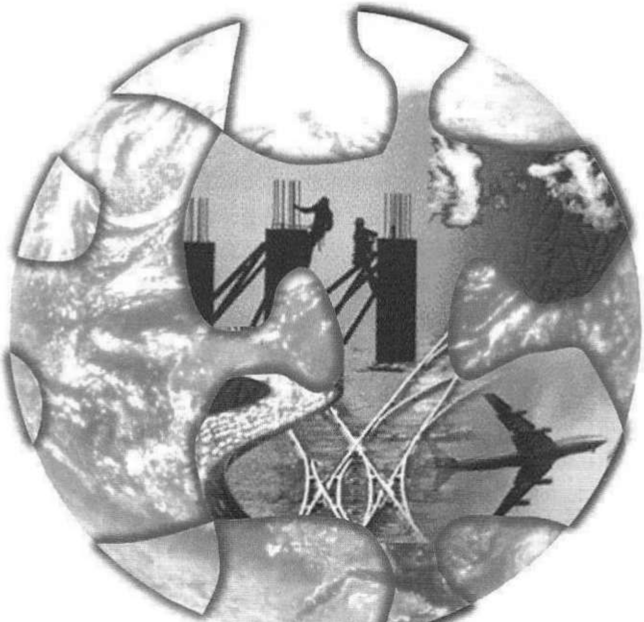
5 The energy submodel: TIME



"Oil has helped to make possible the mastery over the physical world...
Much blood has been spilled in its name."
D. Yergin, The prize (1991)

5 THE ENERGY SUBMODEL: TIME

Bert J.M. de Vries and Marco A. Janssen

This submodel simulates the supply and demand for fuels and electricity, given a certain level of economic activity. It is linked to other submodels, for example through investment flows, population sizes and emissions. The energy model consists of five modules: Energy Demand, Electric Power Generation, and Solid, Liquid and Gaseous Fuel supply. Effects such as those of depletion, conservation, fuel substitution, technological innovation, and energy efficiency are incorporated in an integrated way, with prices as important signals. Renewable sources are included as a non-thermal electricity option and as commercial biofuels.

5.1 Introduction

Modern societies as they have developed over the last two centuries require a continuous flow of processed fuels and materials. Until some 200 years ago energy needs were largely met by renewable fluxes such as water and biomass. Since then energy has increasingly been derived from the fossil fuels coal, oil and gas. To be useful these fuels have to be extracted, processed and converted to heat and chemicals. For all these steps the production factors labour, land, capital, and energy and material inputs, are required. All three steps are also accompanied by waste flows, the largest being the emission of carbon dioxide (CO_2) during combustion. *Figure 5.1* shows the use of fossil fuels in million tonnes of oil equivalents over the period 1800-1990. The graph shows an increase in the use of coal, followed by the penetration of oil and later natural gas. Superimposed on this are the flows of hydropower and nuclear energy, both in the form of electricity. Traditional biomass (not shown) is also an important energy source; its share is estimated in the order of 55 EJ/yr, i.e. about 13% of total world energy use (Hall and House, 1994).

Coal is a relatively abundant resource in comparison with liquid and gaseous carbon fuels. It fuelled the Industrial Revolution to a large extent and as late as 1930 it was still the dominant commercial fuel. In the 1950s the coal industry was still one of the major industries in the world, employing 1.6 million people; almost two-thirds of world output was concentrated in Great Britain, Germany and the USA (Gordon, 1970; Woytinski and Woytinski, 1953). Since then the contribution made by coal in the commercial energy market has been declining and China, with 26% of world output, has become the largest producer, followed by the USA, with 24% (Anderson, 1995a). The main reason for this is the growing availability of cheap and convenient oil and gas.

Crude oil and a variety of fuels derived from oil have provided an increasing

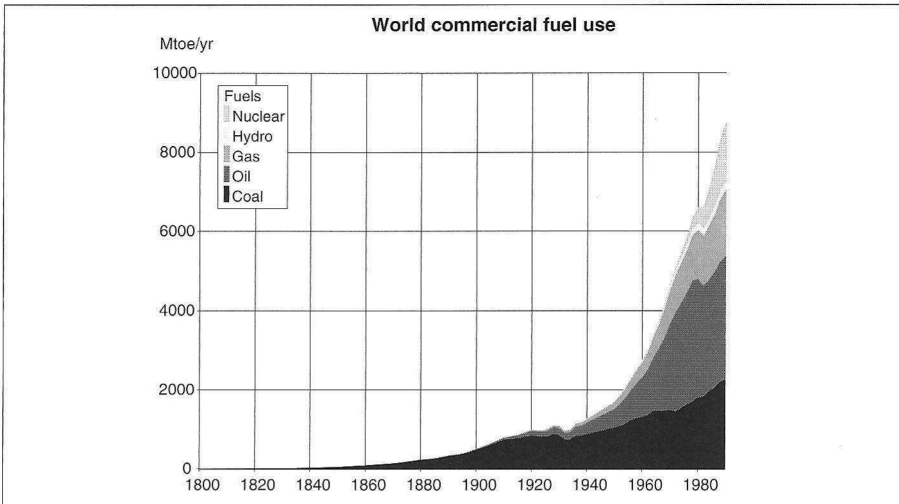


Figure 5.1 Use of fossil fuels and hydro and nuclear power in the world, 1800-1990 (Klein Goldewijk and Battjes, 1995).

proportion of the world's energy needs. Oil products dominate the transport sector: in 1990 transport in the OECD used 37.5 EJ, 99.2% of which was in the form of oil and oil products (Statoil and Energy Studies Programme, 1995). Oil and oil products are among the most widely traded commodities in the world with 80% of all oil produced being traded internationally (Subroto, 1993). Oil exploration, production and processing are to a large extent controlled by multinational oil companies. The involvement of national governments is important because in several countries oil is a significant and in some cases dominant source of government and export income[1]. Since the 1930s natural gas has become a major commercial fuel, first in the USA and later in Europe and Russia. Convenience of use gives it a clear premium value, but transport costs per unit of energy are still much higher than for coal and oil. Flaring of natural gas is becoming less common but still accounts for an estimated 10% of world production. Electric power generation is an important and growing part of the energy-supply system. In the industrialised countries the share of electricity in total final energy use rose from less than 7% around 1950 to more than 17% around 1990 (Nakicenovic, 1989). Construction of power plants and transmission and distribution networks absorb a sizeable proportion of national investments, especially in the early stages of establishing power supplies[2]. Thermal electric power plants require large amounts of fossil fuel, causing major emissions of oxides of carbon, sulphur and nitrogen.

1 This is not only true for OPEC countries like the Arab states, Venezuela, Nigeria, Mexico and Indonesia, but also for oil and gas producers such as Norway, Great Britain and the Netherlands.

2 Annual investments in the electric power sector in the 1990s in the developing countries are estimated at $US 10^{10}, equivalent to 12% of total domestic investments (Nakicenovic and Rogner, 1995).

In recent decades numerous analyses have been published on the future of the global energy system, but the emphasis has shifted from the issue of depletion of accessible oil and gas reserves to analyses of the costs and potential of nuclear and renewable energy options. With the fall in the oil price in the 1980s, the focus shifted to the environmental impacts of continued fossil fuel use, which has revived the need for research and development programmes for renewable energy and safe nuclear reactors. With rising oil imports in some OECD countries, strategic issues are becoming prominent again.

In this chapter we first discuss the major issues in energy policy. Next, the energy submodel is described, first as part of the integrated TARGETS framework and then in terms of the separate modules. The focus is on the links between demand and supply, with prices as an important signal for investment and fuel use decisions. Finally, we discuss the calibration of the model for the world at large and the calibration results for the period 1900-1990.

5.2 Energy issues

The major issues for long-term energy policy are how energy use per unit of activity will develop, the extent to which fossil fuels will be available at what costs, whether fossil fuel combustion will have to be constrained because of environmental impacts from emissions, and if so what alternatives will be available and at what costs. Underlying these issues are questions of technology development and transfer, energy prices, and industrial restructuring and consumption patterns. What has been called the energy transition (Naill, 1977) is primarily seen as the shift from fossil fuels to biomass and other solar-based forms of energy. Here, we briefly indicate four major themes; the controversies surrounding them are discussed in more detail in Chapter 13.

Declining energy intensity

In the last few decades energy – and material – intensities have been declining in the industrialised regions. The major reason is a change in activities, products and processes, in combination with new technologies and materials (Grübler and Nowotny, 1990)[3]. It is as yet unclear whether this trend will persist. On the one hand, it is counteracted by trends which go with rising income, e.g. an increasing number of luxury cars and decreasing household size. It may also be reinforced, for instance, through saturation tendencies, less emphasis on material goods and increasing support for 'green' technologies and investments.

3 The change has been variously described as a transition to a service economy, the information age, the prosumer society and the like. It is also denoted by such concepts as dematerialisation and ecological restructuring.

The less industrialised countries are experiencing an industrialisation process which in some respects is similar to the earlier one in Europe and North America. This has resulted in a rise in energy intensity but to levels well below the ones observed in the past for the present OECD countries. In our model changes in energy intensity due to changing activity patterns, products and processes ('structural change') are distinguished from energy conservation. A further distinction is that the latter is split into autonomous and price-induced parts. Unfortunately, even at the sectoral level it is difficult to separate the structural and the price-related changes in energy intensity from autonomous trends (Schipper and Meyers, 1992).

Depletion of fossil fuel resources

The debate about the quantity and quality of (energy) resources has a long history. In some periods, the general mood was dominated by concern about imminent depletion – as in the report to the Club of Rome, 'Limits to Growth' (Meadows *et al.*, 1972), in which depletion of natural resources may become a major cause of industrial collapse. In other periods, it was a non-issue or the general attitude was that undiscovered resources were vast. What really matters is resource quality (in terms of depth, seam thickness, composition and location). In combination with geological probability and prevailing technology and prices, resource quality determines which part of the resource base is considered to be the technically and economically recoverable reserve. There is general agreement that the coal resource base is large enough to sustain present levels of production throughout the next century without major cost increases (Edmonds and Reilly, 1985). Estimates of long-term supply cost curves for conventional crude oil and natural gas are more controversial (McLaren and Skinner, 1987). Liquefaction and gasification of coal and unconventional oil occurrences like tar sands and oil shales also play a recurrent role in the debate.

Emissions from fuel combustion

Fossil fuel (product) combustion is by far the largest source of anthropogenic emissions of carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrogen oxides (NO_x, N_2O), methane (CH_4) and carbon monoxide (CO). Coal is the major culprit, having a specific CO_2 emission coefficient twice that of natural gas. Emissions of SO_2 and NO_x, which are causing serious air pollution, can technically be reduced but the necessary measures are costly (RIVM, 1991). Reduction of CO_2 emissions is possible by increasing energy efficiency, reducing activity levels or switching to non-carbon fuels; the option of CO_2 removal may become feasible in the future for large-scale combustion processes. Assuming relatively scarce low-cost oil and gas resources, many official forward projections indicate an increase in coal use and in CO_2 emissions (IIASA/WEC, 1995; Leggett *et al.*, 1992). Of course, this hinges to a large extent on the assumptions about energy demand growth and on the role of non-carbon energy sources, as is discussed in more detail in Chapter 13.

Alternatives to fossil fuel

There is a long-term trend in the global energy system towards fuels with a lower carbon to hydrogen ratio: away from coal and towards methane. Major options for a further decarbonisation are nuclear energy and electricity from renewable sources. Whereas expansion of hydropower is less than expected due to the increasing awareness of side-effects of large dams, the prospects for electricity from solar photovoltaic cells and wind turbines are improving as costs are declining. Another option to reduce net anthropogenic CO_2 emissions is the production of liquid and gaseous fuels from biomass. Apart from food and fibre biomass is an important source of both energy and materials. After upgrading, biomass can become a substitute for gasoline as is the case in Brazil and the USA, or can be used in electric power generation. There are still major uncertainties about the rate at which biomass fuels can penetrate the market (Johansson *et al.*, 1993).

Other issues with regard to the energy system are strategic dependence and capital requirements. OECD countries are again becoming more dependent on oil from the Middle-East oil; for the fast growing economies of East Asia oil may also soon become a security issue (Calder, 1996). Expansion of the energy system will require enormous investments, an increasing share of which will be needed in the presently less developed regions (Dunkerley, 1995). Capital shortage and the resulting electricity shortages are already thwarting economic growth aspirations in several countries.

5.3 Position within TARGETS

The Energy submodel has been developed as part of the TARGETS and IMAGE models, hence its acronym TIME (Targets IMage Energy model). It simulates the demand for commercial fuels and electricity, given economic activity levels, and calculates the required investments and land to supply these fuels as well as the costs – which then affect demand. The energy model consists of five modules: Energy Demand (ED), Electric Power Generation (EPG), Solid Fuel (SF), Liquid Fuel (LF) and Gaseous Fuel (GF) supply. Energy demand is calculated from sectoral activity levels, which are calculated in the economic scenario generator. This demand is converted to demand for solid, liquid and gaseous fuels, and for electricity, taking into account autonomous and price-induced changes in the energy intensity and price-induced substitution between fuels. Demand for electricity is supplied from either thermal or non-thermal power plants. Demand for secondary fuels, including that for the generation of electricity, is met by primary energy from the three supply sectors. *Figure 5.2* overviews the five modules. A more detailed model is given in de Vries and van den Wijngaart (1995).

The Energy Demand module is the pressure module within the PSIR framework set forth in Chapter 2. It results in capital stocks which exploit and process fossil

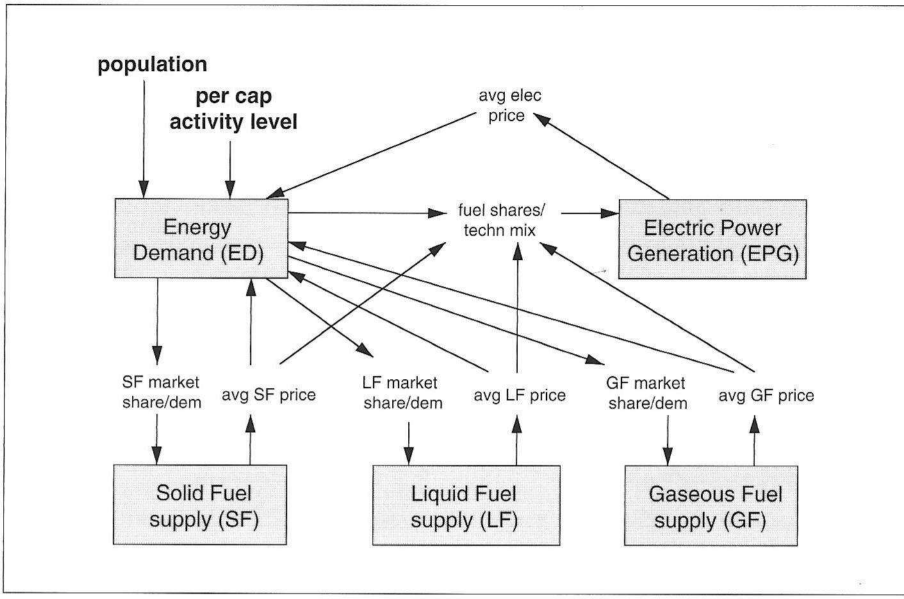


Figure 5.2 The five modules in the Energy submodel.

fuels, generate electricity and increase energy efficiency. Along with the remaining fossil fuel resources, these capital stocks represent the state of the system. Emissions from fossil fuel combustion and use of land for biomass are among the impacts. The response system is endogenous insofar as energy conservation, fuel demand and investment decisions in fossil fuel supply and electricity generation are determined through costs and prices as intermediary variables. There are also exogenous response variables, the most important of which is the levying of fuel taxes and the implementation of demonstration programmes for non-thermal electricity technologies and commercial biofuels.

There are a number of links between the Energy submodel and the other submodels within TARGETS. First, there is interaction between the Energy submodel and the Population and Health submodel: energy demand depends on the exogenous levels of economic activity in absolute terms but also in per capita terms. A second, important link is the one between the Energy model and the CYCLES model. The combustion of fossil fuels generates emissions of CO_2, SO_2, NO_x, N_2O and CH_4, which serve as input for the CYCLES submodel. The land requirements for biofuels are supplied to the TERRA submodel and allocated to grassland and arable land. The expansion of hydropower is linked to the AQUA submodel. The required investments for the energy system are used in the economic scenario generator. *Figure 5.3* indicates the Energy submodel and its interactions with other TARGETS submodels.

During the construction of the various modules we were guided by a few explicit objectives. First, the modules should adequately reproduce the 1900-1990 data on sectoral secondary fuel use, exploration and exploitation in the fuel supply sectors and electricity generation for the world at large. The issue of calibration is dealt with in section 5.7. Secondly, depletion in the form of rising average production costs and technological progress in the form of learning-by-doing have to be incorporated. Thirdly, fuel prices are calculated from capital and labour costs, and should function as signals to direct investment behaviour. Finally, the modules have to allow for at least two non-carbon alternatives, one in the heat market and one in the electricity market. Most modules have also been implemented for the USA and India for 1950-1990 as a basis for validation (van den Berg, 1994). The fossil fuel submodels build on previous energy models, like the Fossil-2 model (AES, 1990; Naill, 1977) and a system dynamics model of the US petroleum sector (Davidsen, 1988). The Energy Demand and Electric Power Generation module build on work from, for example, Baughman (1972), de Vries *et al.* (1991) and Schipper and Meyers (1992).

Evidently, there are deficiencies and omissions in the Energy model, partly a consequence of the very attempt to construct a generic model from regional/local-scale observations and descriptions to be applied at a global scale. Some of these are less relevant because they hardly affect the overall long-term system behaviour. For example, there is the aggregation of various solid fuels into a single one with fixed characteristics. Others may be relevant but more simulation experiments are needed before their consequences can be assessed. For example, the price-driven investment

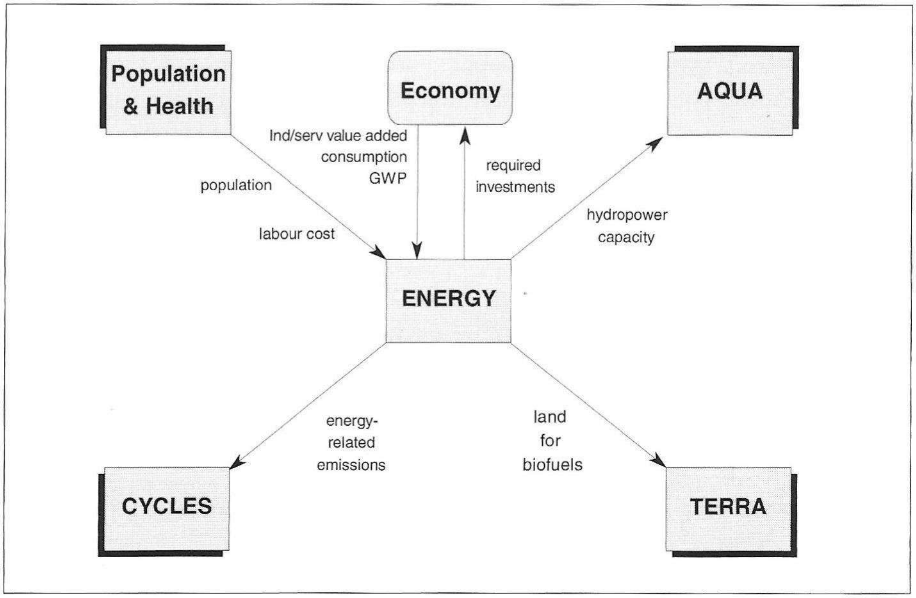


Figure 5.3 The Energy model within the larger TARGETS framework.

behaviour within the oil and coal sectors may be adequate for the USA but fail to capture crucial dynamic factors in regions like China and India. Some elements are not included, which restricts the domain of applicability. Among these are the traditional fuels; the use of fossil fuels and biofuels as feedstocks are not considered either[4]. The options of coal liquefaction/gasification and of Combined Heat and Power are not implemented; capital, labour and land markets are absent; prices and revenues are related to investment decisions but without tracing the corresponding money flows and their macro-economic consequences.

5.4 The energy demand module

End-use energy demand before technology and prices

The main elements of this module were first developed, as part of the ESCAPE and later, as part of the IMAGE2.0 project (Alcamo, 1994; Rotmans *et al.*, 1994). The background for the Energy Demand module is based on the distinction between three determinants of energy intensity: changing activity patterns, products and processes ('structural change'), Autonomous Energy Efficiency Improvements (AEEI, 'technology') and Price-Induced Energy Efficiency Improvements (PIEEI, 'prices'). In the model we first calculate the end-use energy demand which would result without any changes in technology or prices. This, it should be noted, is a non-observable quantity. It is calculated for five different sectors: residential (or consumption), industrial, commercial (or services), transport and others (Toet *et al.*, 1994). Two forms of sectoral end-use energy forms, heat and electricity, are distinguished[5]. Aggregate electricity end-use demand and sectoral heat end-use demand is driven by the product of population and the so-called structural change multiplier, *SCM*. This multiplier, a function of a per capita activity indicator, is calculated for each sector. The multipliers capture the effects of structural change, (i.e. the change in composition of the economic activity) on end-use energy demand. In equation form:

$$SCM_t = \varepsilon_t / \varepsilon_{1900} = [\, \varepsilon_{A \to \infty} + (\beta_1 + \beta_2 A_t)\, e^{-\beta_3 A_t} \,] / \varepsilon_{1900} \tag{5.1}$$

where ε_t is the energy intensity (in GJ per \$) and A_t the sectoral per capita activity indicator in year t. Equation 5.1 shows that the SCM multiplier is normalised to the energy intensity in 1900 and that the energy intensity will drop to some lower limit $\varepsilon_{A \to \infty}$, when the per capita activity reaches very high levels. Depending on the choice

4 Due to their variety of supply and use (crop residues, animal dung, charcoal, fuelwood) and their low status as the 'poor man's fuel', traditional fuels are rarely found in the official statistics and are inadequately measured.

5 Heat is a shorthand way of referring to all non-electric end-use applications of energy for which commercial secondary fuels are used.

of the parameters, the SCM multiplier may decline from 1900 onwards or first rise and then decline.

Autonomous and Price-Induced Energy Efficiency Improvement

The calculated end-use energy demand is multiplied by the Autonomous Energy Efficiency Increase (AEEI) multiplier to account for the historical fact that even with falling energy prices energy intensity has dropped in many sectors. Formalisation of the underlying technology dynamics is beyond the scope of the present submodel. Hence, we have introduced this autonomous increase for each sector as an exogenous factor which declines exponentially to some lower limit and is linked through a delay to the turnover rate of sectoral capital stocks. The expression for the *AEEI* factor is:

$$AEEI = \varepsilon^{*}_{limit} + (1 - \varepsilon^{*}_{limit})\, e^{-c \times (t-1900)} \qquad (5.2)$$

where c is the time-dependent, exogenous annual rate of efficiency increase and ε^{*}_{limit} the lower limit on the reduction that can be achieved through *AEEI*. Although the value of ε^{*}_{limit} is related to the second law of thermodynamics, it is hard or even impossible to base it on physical considerations if output is measured in monetary units.

To incorporate the effect of rising energy costs to consumers, we have opted for an intermediate approach between the bottom-up engineering analyses and the top-down macro-economic approach. It is based on an energy conservation supply cost curve which represents the costs and effectiveness of energy conservation options. This curve is assumed to shift over time; its shape determines, in combination with a

Energy conservation and prices

The sectoral *PIEEI* multiplier is given by:

$$PIEEI = B_{max} - 1 / [\sqrt{(B_{max}^{-2} + UECost \times PBT \times (1 + d)^{t-1975} / \alpha)}] \qquad (5.3)$$

where B_{max} is the ultimate reduction achievable, *UECost* the average end-use energy cost and *PBT* the assumed payback time, which energy users apply within the sector. The time-dependent parameter d reflects the autonomous rate at which energy conservation investments become cheaper. It starts in1975 on the assumption that before 1975 no price-induced changes have occured. The parameter α is a scaling constant which allows gauging the curve to empirical estimates. For example, for $B_{max} = 0.9$, the choice of α / B_{max} indicates the level of the average investment costs per GJ conserved, at which a total reduction in energy intensity of 62% is realised.

The *UECost* is calculated by dividing the fuel costs by an average (fuel-dependent) conversion efficiency and adding a (fuel-dependent) fixed capital cost component. It should be noted that this formulation implies the use of a price elasticity which depends on the degree of conservation, the energy cost and on time. The price elasticity tends to go down when energy prices go up, reflecting the phenomenon that price changes induce fewer conservation investments once the cheapest options are introduced. The empirical basis for equation 5.3 is given with the energy conservation curve, which represents the cumulative investments as a function of the *PIEEI* factor, i.e. the price-induced reduction in energy intensity. A variety of such curves has been published in the literature over the past 5-10 years (Blok *et al.*, 1993; Bollen *et al.*, 1996). Reliable estimates are only available for a few countries.

return-on-investment criterion, how many energy efficiency investments are made. Energy demand after AEEI is multiplied by a factor, 1 – PIEEI. The value of the Price Induced Enery Efficiency Improvement (PIEEI) multiplier is determined by end-use energy costs which in turn depend on prices and market shares of secondary fuels. Key parameters are the gradient of the sectoral conservation investment cost curve and the desired payback time which consumers use in deciding to invest in energy conservation. This mechanism, applied irreversibly and with a delay in the sense that action is only taken if energy end-use costs go up, is extended with another factor which lowers the cost curve over time according to an exogenously set rate. This is a simple way to account for the fact that regulation and mass production will tend to make many energy-efficiency measures cheaper over time.

Secondary fuel demand

Electricity demand after AEEI and PIEEI is met by electric power generation as described in the EPG module (Section 5.6). Heat demand after AEEI and PIEEI is satisfied by a price-determined mixture of solid, liquid and gaseous fuels. The next step is to convert this into a demand for secondary fuels. We distinguish four commercial fuel types in the TIME submodel: solid, liquid and gaseous fuels, with the liquid fuels split into light (LLF: gasoline, kerosene etc.) and heavy (HLF: fuel oil and distillates). Fuel wood in the residential sector and all kinds of agricultural and industrial waste flows used for energy functions are not (yet) included. The market shares of these four commercial fuels are calculated for each sector from their relative prices through a multinomial logit function (Bollen *et al.*, 1995, 1996). In the model, actual market shares follow, with a delay, these economically indicated market shares. The change in market shares affects the end-use costs, which in turn determine the degree to which energy conservation actions are taken in year t+1.

There are two additions to this statement. First, the consumers in the five sectors are faced with different prices because transport and storage costs, and taxes and/or subsidies, differ. Moreover, non-price factors influence the decision to use certain fuels, e.g. strategic and environmental. We have therefore introduced a so-called premium factor to incorporate price components which are not included and to account for differences between perceived and actual market prices. These premium factors have also been used to calibrate secondary fuel use. Secondly, the available user technologies and distribution networks did not always allow an unconstrained choice of one of the three secondary fuels. In some cases it turned out to be logical and necessary to constrain the substitutable part of useful energy demand[6]. This we considered a conceptually more plausible approach than adjusting the premium factor to unrealistically high values.

6 For example, road transport was not an alternative for rail transport at the beginning of the century so we confined the market share of the transport sector, for which coal was a possible substitute, to 90% around 1900 to 10% around 1990.

5.5 The fuel supply modules

The three fuel supply modules (solid, liquid and gaseous) have a few aspects in common which will be discussed briefly. First, for all three resource bases (coal, crude oil and natural gas) the exploitation dynamics are governed by a depletion multiplier and a learning parameter. The former reflects the rising cost of discovering and exploitation of occurrences when cumulated production increases. The latter works to the contrary by assuming that the capital-output ratio will decline with increasing cumulated production due to learning-by-doing in the form of technical progress. These effects are taken into account by multiplying the respective capital-output ratios of coal, oil and gas with a depletion multiplier and a technology multiplier (de Vries and van den Wijngaart, 1995). Conceptually, we follow here the often used assumption that the cheapest resource deposits are exploited first. In the past, this has obviously not been the case at the world level. For example, an obvious violation was the discovery of the giant low-cost oil fields in the Middle East (Yergin, 1991). We have therefore inserted these discoveries as exogenous, zero-cost exploration successes. However, the hypothesis may be increasingly seen to be correct because of trade liberalisation and the downward trend in transport costs. For oil there is already effectively one world market; a world coal market is in rapid development (Ellerman, 1995). For natural gas, this is not yet the case due to high transportation costs. Transporting gas in an onshore pipeline might cost seven times as much as oil; to move gas 5000 miles in a tanker may cost nearly 20 times as much (Jensen, 1994).

A second important element in the liquid and gaseous fuel module is the possibility of a non-carbon based alternative fuel penetrating the market. This alternative is confined at present to a biomass-derived liquid/gaseous fuel alternative, for which land will be an important input. Labour may be an important input, especially in low-labour productivity regions. In fact, biofuels may initially only have a competitive advantage – apart from strategic considerations – because large amounts of cheap labour can be absorbed. More specific conversion routes, e.g. hydrogen from biomass, solar heat or electricity, have not explicitly been modelled in the current version. We will now discuss each of the three modules in more detail.

The Solid Fuel (SF) module

The SF module is represented in *Figure 5.4*. The most important short-term loop is the demand–investment–production–price loop. Given a demand for solid fuels from the ED module, the anticipated demand generates investments into new production capacity. These investments form a fraction of the revenues, depending on the price-to-cost ratio, and are distributed among underground and surface coal mining operations on the basis of the production cost ratio. For underground coal the capital-labour ratio rises according to an exogenous time-path. An important longer term loop is the solid fuel price changing in response to depletion and learning, which in turn affects coal demand calculated in the ED module. Learning is incorporated by

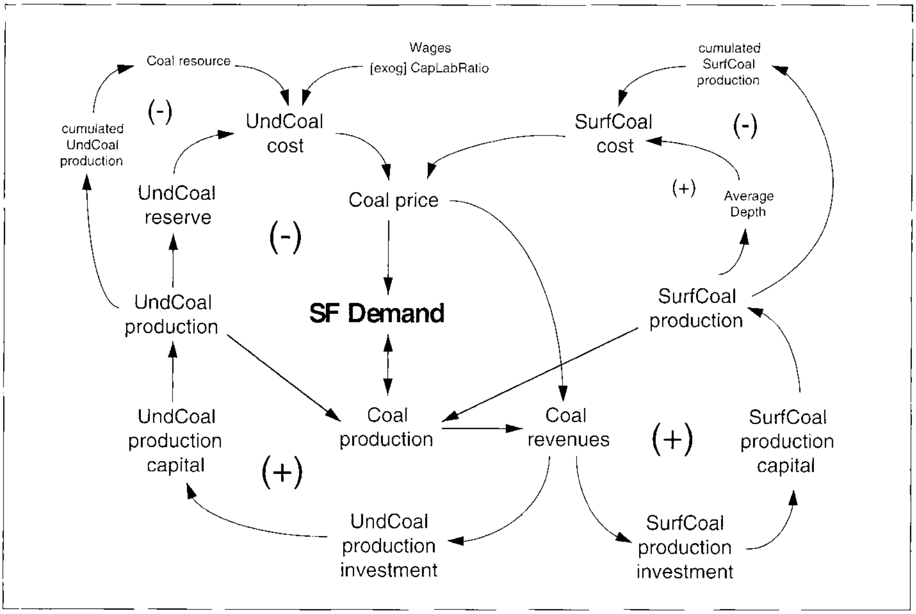


Figure 5.4 The demand-investment-production-price loop in the Solid Fuel (SF) module. The left-hand side represents the demand-driven exploitation loop for Underground Coal (UndCoal) with depletion and capital-labour substitution. The right-hand side is the same for Surface Coal (SurfCoal), along with depletion and learning (COR Capital Output Ratio; CapLabRatio Capital Labour Ratio).

multiplying the capital-output ratio for surface-mined coal by a factor which declines as a linear function of the logarithm of cumulated production. This multiplier is set at one for 1980. The coal price is calculated by adding the capital costs for upgrading and transport. We consider only one generic type of coal, at 29 GJ/tonne, also referred to as 'solid fuel'. The use of coal as feedstock is not accounted for, except in the case of coking coal for pig iron production, where it is part of industrial fuel use.

The life cycle of coal is based on the distinction between the resource base, identified reserves and cumulated production. The resource base is explored and discovered, i.e. converted into identified reserves. An exogenous discovery rate is entered to match trends in past reserve estimates. Coal companies decide to invest in coal producing capacity on the basis of anticipated demand for solid fuel. This anticipated demand represents a trend extrapolation over a time horizon of T years of the form $(1+r)^T$ with r being the annual growth rate in the past 5-10 years. How much is invested in coal production is based on the return on investment value: the larger it is, the higher the fraction of coal revenues re-invested in the industry. The share of this investment flow that goes into underground mining depends on the cost ratio between underground and surface-mined coal in accordance with a multinomial logit function.

The investments add to the coal-producing capital stocks, the output of which is determined by the capital-output ratios, γ_{prod}. These are assumed to depend on three trends which have been observed in the past in various degrees and combinations:

- as exploration proceeds, newly discovered deposits tend to be of lower quality, i.e. deeper, narrower and more distant. This is modelled by dividing γ_{prod} by a depletion-cost multiplier (<1);
- in the labour-intensive underground coal mining, labour productivity increases over time as more capital per labourer is used (Cobb-Douglas form of production function); the capital-labour ratio is exogenous input;
- over time, capital costs to find and produce one unit of coal tend to decline due to technical progress of all forms. For underground mining this is implicit in the capital labour substitution. For surface mining it is modelled by multiplying γ_{prod} by a technology factor (<1), which is a function of cumulated production.

After the calculation of capital stocks, actual coal production equals coal production capacity unless the ratio between coal demand and coal production capacity exceeds 0.9, in which case the coal capital utilisation rate increases to 1.0 for a capacity shortage of 20%.

An important input for the ED module is the coal price. The capital costs of coal are calculated as an annuity factor times the production capital stock, divided by the annual production. For underground mining the labour costs are also included. For surface-coal mining, labour costs are taken to be a fixed and small fraction of the capital costs. The wage rate is assumed to be a time-dependent fraction of average consumption per capita. The average coal cost c_{SF} is a weighed average of the cost of underground and surface coal. The coal price is also influenced by the demand-supply (im)balance through the Supply Demand Multiplier *SDM*. The average mine-mouth price is now given by:

$$p_{SF} = SDM \times a \times c_{SF} / P_{SF} \qquad [\$/GJ] \quad (5.4)$$

with a the annuity factor[10] and P_{SF} the annual Solid Fuel or coal production. If the price changes in response to an excess or shortage of capacity, this decreases or increases revenues, which in turn generates lower and higher investments, respectively with a delay. The last step is to incorporate the capital requirements and resulting add-on costs for transport and upgrading of coal. This is done with a constant factor which also accounts for conversion. It is assumed that 90% of these additional costs are in the form of annuity payments for investments. Energy, mostly Heavy Liquid Fuel, for coal transport is not explicitly included.

10 The annuity factor $a = r/[1-(1+r)^{-EL}]$ with r being the interest rate and EL the economic lifetime of the investment.

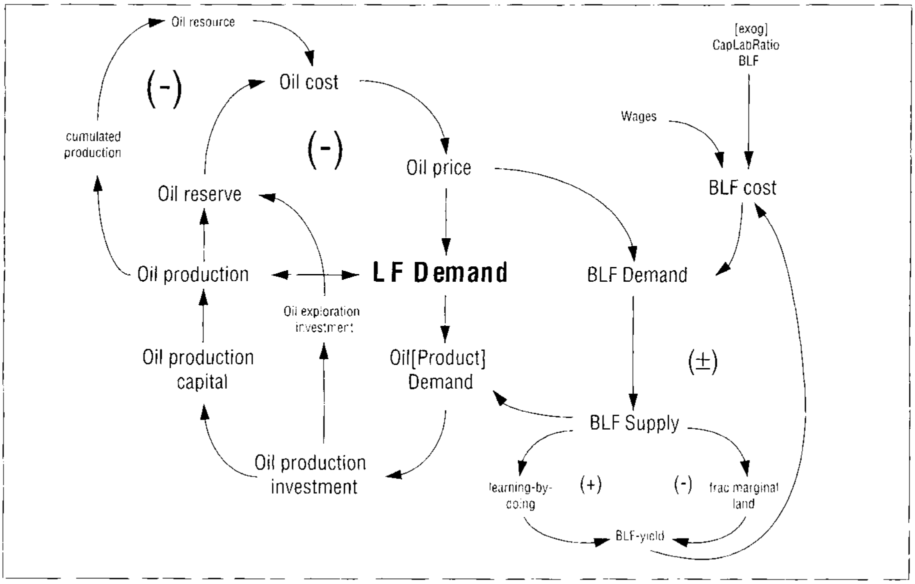


Figure 5.5 The demand-investment-production-price loop in the Liquid Fuel (LF) module. The left-hand side represents the demand-driven oil exploitation loop with price-induced exploration, depletion and learning; the right-hand side represents the penetration, depletion and learning dynamics of BioLiquidFuels (BLF) (COR Capital Output Ratio; CapLabRatio Capital Labour Ratio).

The Liquid Fuel (LF) and Gaseous Fuel (GF) modules

Figure 5.5 shows the LF module as a causal loop diagram. The GF module has an almost identical structure and therefore will be discussed only where it differs from the LF module. Some model elements are similar to the SF module. The most important short-term loop is the demand – investment – production – price loop. The anticipated demand for liquid fuels generates investments into new production capacity. Exploration investments are determined by the desire to keep the reserve-production ratio (RPR) sufficiently high. A certain profit level in terms of revenues over costs is required to sustain exploration investments. In a second loop, the liquid fuel price changes in response to depletion and learning dynamics due to oil production, which in turn affects liquid fuel demand. The underlying mechanisms are a capital-output ratio which rises with declining marginal resource quality and which decreases due to learning-by-doing. Another long-term element is the penetration of biofuels: if biofuels can be produced at competing cost levels, investment will be made in biomass plantations. Costs depend on technology through learning-by-doing and on depletion due to the use of less productive land. There is an impact on food production in the TERRA submodel through land use for plantations.

As with coal, the life cycle of oil and gas is based on the distinction between the resource base, identified reserves and cumulated production. Oil is discovered, i.e. converted from resource into identified reserves, produced and combusted. The ultimately recoverable oil at the technology and price levels throughout the simulation period is itself a function of learning with expert bias (Sterman and Richardson, 1983). The ED module simulates the demand for liquid fuels in two forms: Heavy Liquid Fuels (HLF) and Light Liquid Fuels (LLF)[11]. The fraction of total demand, which is in the form of LLF, is given exogenously. Only a fraction of LLF demand is satisfied by oil products. The remaining market share (μ_{BLF}) is supplied by commercial biofuels (BioLiquidFuel BLF) and depends on the relative cost of LLF and BLF. The required production of crude oil can now be calculated using an overhead factor covering exploitation and refinery energy use and losses. This determines investments in the oil exploitation, and in transport and refining. If the reserve-production ratio (RPR) is below a desired level (RPR_d) and the average market price, $p_{CO,avg}$, is sufficiently high, oil companies will also invest in crude oil exploration[12].

How much to invest in oil production capacity depends on the capital-output ratio, γ_{prod}, of the crude-oil-producing capital stock. New investments are equated to the depreciation of the existing capital stock plus the required additional capacity. The resulting equation is of the form:

$$dC/dt = C_{req} - C/EL \qquad [\$/yr] \quad (5.5)$$

with EL the economic lifetime and C_{req} the additional required capacity, which depends on demand and identified reserves. If the market price is less than the price required to make a profit, investments will be lower than required - as with exploration investments. One assumes it will take some years before investments generate new reserves or lead to oil production. The next step is to calculate the cost of oil products and gas. As with coal, the key factor is the capital-output ratio for production, γ_{prod}, which changes over time, as has been discussed for coal. Capital costs are calculated as an annuity factor times the production capital stock plus the exploration investments divided by the annual oil production. When the ratio between required and potential production approaches or exceeds one, the crude oil price will go up and this will increase exploration and exploitation investments (Supply Demand Multiplier SDM, see equation 5.4). Capital costs for transport and downstream operations (refining) are linked to production capacity and to the LLF fraction to account for be additional cost of 'whitening the barrel'. From this, the costs to deliver HLF and LLF are calculated.

Biofuel penetration is simulated using a production function with capital, labour and land as production factors. A fixed capital-output ratio, g_{BLF}, and an exogenously increasing capital-labour ratio, CLR_{BLF}, reflect the transition towards less labour-intensive techniques. Land requirements are derived from a land-output ratio, β,

11 In the GF model no distinction is made between various types or grades.

12 The dynamics of recovery technology, which allows a larger fraction of the oil-in-place to be produced, is not explicitly taken into account (Davidsen, 1988).

which increases due to technology and decreases when the exogenously set supply potential is reached. The latter represents the assumption that increasingly less productive land is used for biomass plantations. Given some initial estimate of the cost of BLF, the penetration dynamics rests on the assumption that the market share for commercial biofuels is a function of its cost relative to the LLF price. The economically indicated market share as determined from a multinomial logit formula induces either private or public firms to invest into plantations producing biofuels. Calculating the required amount of labour L_{BLF} from the exogenous capital-labour ratio, the cost of biofuel can be expressed as:

$$c_{BLF} = [a\,(C_{BLF} + P_{BLF}/\beta) + (\mu_{BLF} \times D_{LLF} \times g_{BLF}/CLR_{BLF}) \times p_L\,]/P_{BLF} \quad [\$/GJ] \quad (5.6)$$

with P_{BLF} being the actual BLF supply, a the annuity factor and p_L the price of labour. The BLF price – equated to BLF costs plus a fixed profit margin – in relation to the LLF price will determine its future market share.

5.6 The electric power generation module

Figure 5.6 contains causal loop diagram of the major elements in the EPG module. Most important is the demand–investment–price loop. It simulates the planning process in which a future demand is anticipated on the basis of which new capacity is

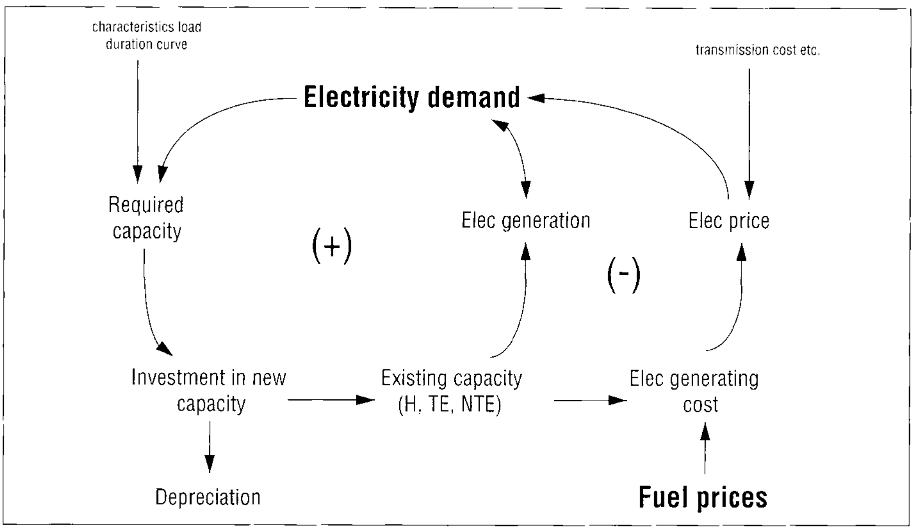


Figure 5.6 The demand – investment – price loop in the Electric Power Generation (EPG) module. Electricity demand leads to investments in new capacity, which determines with the fuel costs the electricity generation costs. The learning dynamics of non-thermal electrical (NTE) power generation is not indicated.

ordered and put into operation if there are no capital or other constraints. In combination with fuel and transmission costs, this determines the electricity price which in turn affects the demand for electricity. We assume that the investor decides on new capacity (in MWe) by anticipating growth in electricity demand in combination with a preferred reserve factor. The three capital stocks represent hydropower, thermal and non-thermal electricity generation[13]. Expansion of hydropower (H) capacity is an exogenous scenario, assuming increasing marginal specific investment. Whether the remaining new capacity ordered is thermal electric (TE) or non-thermal electric (NTE) is based on the difference between the production costs. The characteristics of the three capital stocks, hydropower, thermal and non-thermal electric, change over time. For thermal power plants, conversion efficiency and specific capital costs (in dollars per MWe) are exogenous time paths. For the non-thermal power generating options, cumulated production induces learning, which shows up as decreasing specific investment costs and hence lower total costs. This in turn will accelerate the share of these options in investments. The market share of each of the three fuels (solid, liquid, gaseous) is based on relative fuel prices[14].

Operation of electric power systems is done on the basis of rather sophisticated operational rules (de Vries *et al.*, 1991). A number of simplifications have been introduced. First, the net demand for electricity from the ED module is converted into anticipated gross demand similar to fuel demand and split into two fractions: base load and peak load. The calculation of the required capacity, and hence the required investments, is then derived from the assumption that each generating option has a constant load factor, i.e. fraction of the year that it is operated. From this, the thermal capacity required for base-load operation is calculated[15]. The required peak-load capacity, E_p, is then calculated as:

$$E_p = (1 - BF) \times ED_{gr} / (PLF_{max} \times \beta) \qquad \text{[MWe]} \qquad (5.7)$$

where ED is gross electricity demand, PLF_{max} the maximum load factor for capacity operated in the peak-load periods, $PLF \leq PLF_{max}$, and β the conversion factor from GJ to MWe ($\beta = 8760 \times 3.6$). The total required installed capacity is the sum of required base-load plus peak-load capacity, including a reserve margin to guarantee a desired level of reliability in the load-factor estimates. From this the required investments are calculated.

13 For the world at large, this is not unrealistic; for smaller regions resources like hydro and windpower, with their seasonal variations, cannot be simulated accurately in this way.

14 There is one generic type of thermal power plant. Differences in capital and operating costs, and efficiencies, are assumed to average out and all thermal capacity is, with a delay, assumed to be multifiring.

15 With a large expansion programme for non-thermal and hydro capacity, this may become negative, in which case it is set equal to zero.

If the required production implies $PLF > PLF_{max}$, there is capacity shortage and only the fraction PLF_{max}/PLF of peak demand is produced. Such a situation can result from an unexpectedly fast increase in demand combination with long construction periods or delays, or when the economy cannot or does not sustain the required investment flows. Also the fairly low reliability of power stations and transport systems contribute to capacity shortages and unsatisfied demand, a situation which occurs in various parts of the world. The reverse, overcapacity, shows up as increasing costs which negatively affect demand. If the ratio between the actually installed and the required system's capacity drops below one, the anticipated required electric power capacity is divided by this ratio; this provides an additional signal to install new capacity. If there is no capital constraint, the investments lead to expansion of the three electricity-producing capital stocks. The capital stock for transmission is taken to be proportional to the system's installed capacity.

For thermal electric power generation an important question is which fuels are used. In the EPG module the answer to this question is based, as in the other modules, on relative prices. A premium factor is used to allow for differences between fuel costs and the prices as perceived by utilities[16]. The next step is to calculate electricity prices, since they are input for the ED module. This is done in a way similar to the cost calculations in other modules: capital costs are put on an annuity basis and fuel costs are derived from fuel use times fuel prices. The penetration dynamics of non-thermal electric power technology (e.g. nuclear, solar) is governed, as with biofuels, on the basis of the relative generation costs of the thermal and the non-thermal option. Again, a multinomial logit formulation is used. It implies that the learning coefficient is crucial for the penetration of non-thermal capacity because this largely determines the rate at which specific investment costs decline as a function of cumulated production. This is a positive, reinforcing loop. If the sum of hydropower and non-thermal capacity exceeds the required base-load capacity, non-thermal capacity will also be put into operation for peak load whenever thermal capacity is less than the required peak-load capacity (see equation 5.7)[17]. Hence, its average load factor decreases; this drives up non-thermal generating costs, which in turn will slow down its penetration rate – a negative, stabilising loop.

5.7 Calibration

Procedure and assumptions

Calibration has been done for the period 1900-1990 for the whole world. The

16 For example, for electricity generation in OECD Europe, Moxnes (1989) has found that as of 1983 coal has a premium equivalent to a price discount of 29%, whereas natural gas has been discriminated against at the equivalent of a 12% price increase.

17 It is assumed that hydropower will never exceed the required base-load capacity.

statistical data used for the calibration come from a variety of sources (International Energy Agency IEA, 1990; Klein Goldewijk and Battjes, 1995). First, historical data on commercial fuel use have been collected and used to calibrate the ED module. For this, sectoral activity levels[18] and sectoral fuel prices to drive the model are employed. Important parameters for the calibration are: the end-use energy demand as a function of activity level (Equation 5.1), the rate of autonomous energy efficiency increase (AEEI) and its lower boundary (Equation 5.2), the form of the conservation investment cost curve and its rate of change (Equation 5.3), and the fuel cross-price elasticities and premium factors.

In a second step, each of the four supply submodules has been calibrated, using historical supply and price paths. Supply has been set equal to demand. The most important variables in the calibration are: the resource base estimates; the capital-output ratios and the corresponding depletion multipliers for coal, oil and gas; the substitution coefficients for the various investment allocations; the efficiency of thermal capacity and the premium factors for fuels used for electric power generation. The learning coefficients for surface coal mining, oil and gas exploitation, biofuels and non-thermal electric power generation have also been adjusted. The costs of nuclear-electricity, the dominant NTE option, have increased because of additional safety measures and long construction delays. In the model this has been reproduced by assuming a negative learning rate for the period 1965-1990. The supply-demand multiplier relations (Equation 5.4) are adapted from Naill (1977), Davidsen (1988) and Stoffers (1990)[19]. For a more detailed discussion, see de Vries and van den Wijngaart (1995), de Vries and Janssen (1996) and van den Berg (1994).

To perform the calibration for the integrated submodel, we needed a number of iterations during which a limited set of parameters within the four supply modules had to be adjusted to correct for minor discrepancies between simulated and historical values. It should be noted that model calibration is not an unambiguous procedure. In the ED module, for example, end-use energy demand is a non-observable quantity: it is implicit in the actual observations of secondary fuel use and activity level. Hence, a multiplicity of parameter calibrations is possible. The same holds for the relative importance of technology vs. depletion in the fuel supply modules.

Results

Figures 5.7a-h show a series of simulation results for the world of 1900-1990. Simulated total secondary energy use is compared with historical primary energy use

18 We have chosen the indicators used in IMAGE2.0: value-added in stable (1990) US dollars for industry and commerce, consumption expenditures in stable (1990) US dollars for residential areas, and GWP in stable (1990) US dollars for transport and other (Toet *et al.*, 1994).

19 Two exogenous events were introduced which cannot be expected to be simulated, as the underlying dynamics do not form part of the model formulation: discovery of large oil fields between 1950 and 1970 (Middle East) and a crude oil-price increase of 50%-400% between 1973 and 1987 (oil-price crises).

because there is no data on secondary energy use (*Figure 5.7a*). As can be expected, primary energy use is higher but the trends are correct. Simulated electricity use closely match with historical data. The key assumptions – and hence ambiguities – concern the structural change multiplier and the rate of autonomous efficiency improvements. We had to assume rapidly increasing energy intensity for the transport sector and electricity to represent the emergence of new transport modes and electrical applications. The substitution dynamics from traditional to commercial fuels, especially relevant for the residential and industrial sector, are implicit in the structural change parameter estimates. Only after the rise in fuel prices in the 1970s, do the price-induced energy efficiency improvements cause a slightly faster decline in energy intensity. It turned out that for all sectors premium factors different from unity are required to simulate the substitution among secondary commercial fuels. There is a variety of possible and sometimes plausible explanations, one of them being that we have kept the conversion efficiency (from secondary fuel to useful demand) constant[20] and another one being the differences in quality and convenience.

Electricity was supplied by hydropower, thermal and non-thermal electric power capacity. *Figure 5.7b* shows the emerging dominance of thermal capacity, with coal as the major fuel and the reduced growth in fossil fuel use due to the introduction of nuclear (NTE) capacity. Coal is the major fuel used to generate electricity (*Figure 5.7c*). The rise in oil prices in the 1970s shows up as a declining share of Heavy Liquid Fuel. For coal we had to apply a cost reduction which reflects the lower coal prices for large-scale utility users.

The fuel supply side is shown in *Figure 5.7d-f*. For all commercial fuels, the model generates declining prices until 1970, when exogenous price shocks were applied (*Figure 5.7g*). The jumps in the two first decades are partly caused by the

Prices and technology – their relative importance

To understand the role of energy prices in the model, we did some experiments in which the exogenous oil price crises were left out. It turns out that its impact mean a slow-down in energy use and a smaller market share for oil, as expected. Setting all premium factors to zero causes oil and especially gas to penetrate much faster than has happened historically. Evidently, the premium factors also account for the lack of infrastructure (pipelines, equipment) which significantly delayed the use of natural gas. If the exogenous technological constraints in the model are also removed, the system immediately jumps to the present market shares for oil and gas, which is a price-determined equilibrium. The longer term consequence is that oil and gas are depleted more rapidly and coal is regained earlier and stronger. These simulation experiments point to the importance of non-economic factors in explaining the energy system evolution over the past 90 years. Our simple way of introducing the complex dynamics of technical innovations in the form of exogenous constraints to market penetration turns out to be a decisive factor in calibrating the model.

20 The conversion efficiencies from secondary fuel to end use are the same for all sectors and constant, at 0.65 for coal, 0.75 for liquid fuels and 0.85 for gaseous fuels.

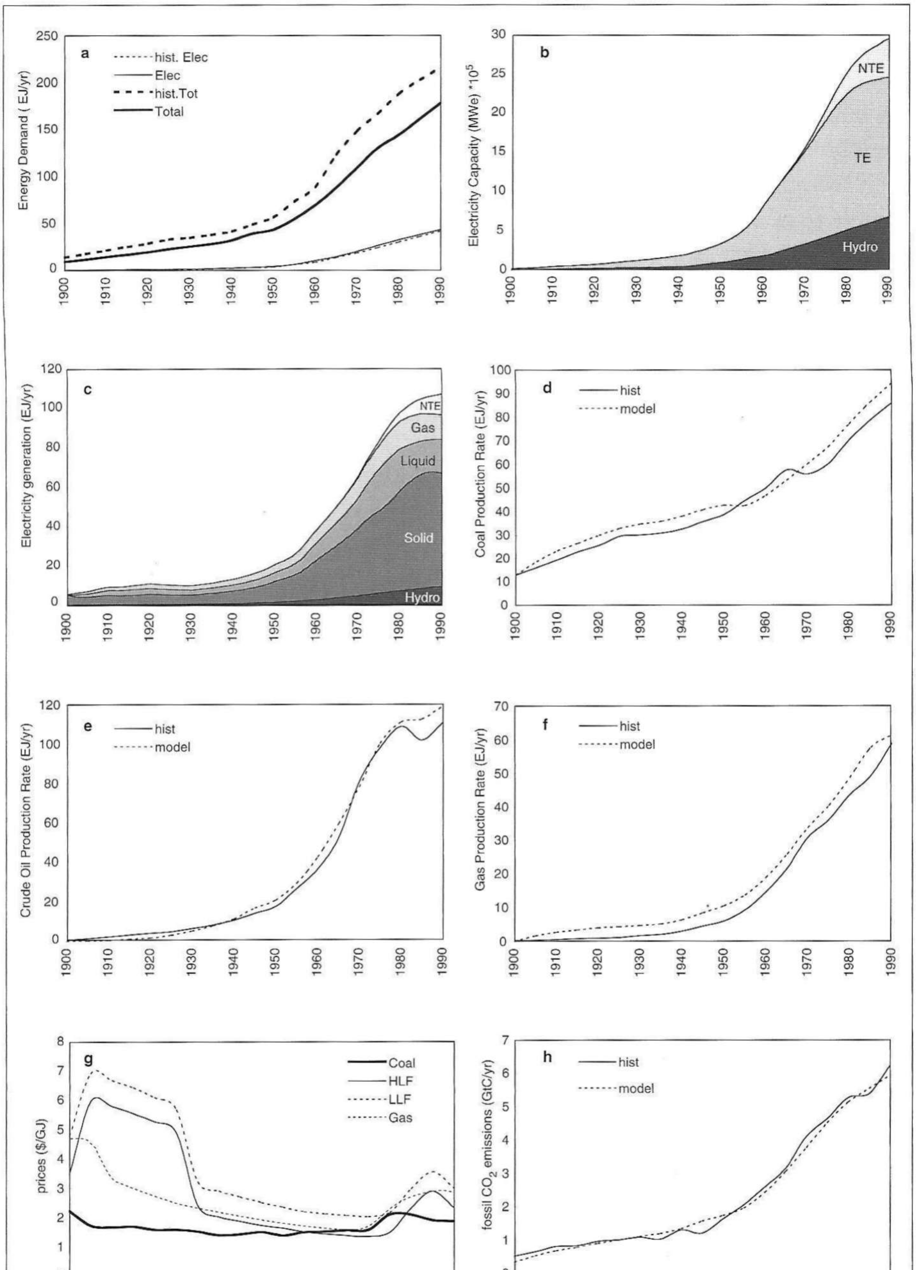


Figure 5.7a-h Simulated primary fuel use and electricity use follow historical trends (a); so do coal, crude oil and gas production (d - f) and CO_2 emissions (h). Prices decline until 1970. Then exogenous price shocks are applied (g).

model initialisation. For thermal electric power generation, costs are also declining but for nuclear power, adjustment of the learning factor causes the historical rise in costs. Rising underground-mined coal costs due to rising labour costs and depletion are mitigated by the penetration of lower-cost surface-mined coal. For oil and gas, the exploration and production costs are low and declining, because between 1900 and 1990 learning-by-doing is assumed to have compensated the increasing scarcity of the reserve base. For natural gas, the actual market price for consumers is initially much higher than what is calculated from supply-side considerations because of a high premium factor. Total primary energy use and their shares can be reproduced fairly well with the simulated demand and prices. The resulting CO_2 emissions from fossil-fuel combustion are within 5% of estimates in the literature (*Figure 5.7h*).

5.8 Conclusions

On the basis of simulation experiments carried out thus far, several conclusions can be drawn which highlight some characteristics of the Energy submodel. A first conclusion is that energy conservation in response to rising secondary fuel and electricity prices can be expected to slow down unless one assumes that standardisation and learning etc. continuously reduce the costs at which such efficiency improvements can be realised. Secondly, substitution between fuels tends to dampen price increases in any one particular fuel, unless secondary fuel prices are linked through markets or government agreements. This effect, however, is rather small and is influenced by the assumption of constant conversion efficiencies from secondary fuels to end-use. Thirdly, autonomous increase in energy efficiency can be expected to be the major determinant of sectoral fuel and electricity use, but the level of useful energy per monetary unit of activity is an equally important factor in the longer term.

With regard to fuel supply, the main conclusion is that the simulations correctly reproduce the historical time paths of reserves, production and costs until 1975. However, this requires a rather intuitive assessment of the relative importance of depletion and technology effects. The oil crisis of the 1970s caused a sequence of events which can only be reproduced by adjusting parameters in such a way that they implicitly account for mechanisms and behaviour which are absent in the model. The absence of an explicit coupling between coal, oil and gas prices is one of the causes of discrepancies between simulation results and historical data. A few topics, among them the formation of secondary fuel prices, the availability and cost of labour, and the quality characteristics of the reserves deserve closer scrutiny. Because the simulation experiments presented here are for a single global aggregate, interactions between regions are absent which, may be highly relevant in the real world. This aspect will be introduced in the next, regionalised version of the model as part of the IMAGE 2 model.