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Energy Sector for the Integrated System Dynamics Model for Analyzing Behaviour of the Social-Economic-Climatic Model

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VERITAS ET UTILITAS

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Abstract

The system dynamics-based energy sector described here adds a representation of energy supply and demand dynamics, and their associated carbon emissions, to a larger society-biosphere-climate model previously described in Davies and Simonovic (2008). The inclusion of an energy sector expands the earlier model considerably, and provides new avenues for its application to policy development.

Five interconnected components constitute the full energy sector: demand, resources, economics, production, and emissions. The energy demand component calculates changes over time in heat-energy and electric-energy demand as a result of economic activity, price-induced efficiency measures, and technological change. Energy resources models changes in the amounts of three non-renewable energy resources -- coal, oil, and natural gas -- as a result of depletion and new discoveries. Energy economics, the largest of the energy sector components, models investment into the maximum production capacities for primary energy and electricity, based on market forces or the prescriptions of policy makers. Energy production represents the supply portion of the energy sector by producing primary (heat) and secondary (electrical) energy to meet energy demands; six electricity production technologies are included, and other options can be added relatively easily. Finally, energy emissions calculates the carbon emissions resulting from the combustion of fossil fuels to meet energy demands, and includes important non-energy processes such as cement production and natural gas flaring.

The body of the report is organized into seven chapters and four appendices. Chapter one serves as an introduction to the document and describes the basic principles and structure of the energy sector. Chapters two through four begin with a brief literature review and description of relevant real-world data, explain the model structure and its development, and end with a summary of preliminary model results. Specifically, chapter two describes the energy supply components of the model (resource extraction and electricity investment and production), chapter three describes the energy demand component, and chapter four describes carbon emissions modelling. Chapter five provides background information on modelling technological change. Chapter six explains the manner in which the energy sector was calibrated to a 1960 start-date and its integration into the larger multi-sectoral model of Davies and Simonovic (2008). Chapter seven describes the integrated model's capabilities and use, limitations, and areas for improvement. The four appendices provide a full listing of all energy sector equations and cross-reference each to the relevant section of the report body (Appendix A), and describe and explain alternative approaches toward the modelling of electricity production capacity (Appendix B), fuel prices (Appendix C), and energy demand (Appendix D).

Key words: integrated assessment model; society-biosphere-climate model; energy; system dynamics; model description; Vensim DSS

The Energy Sector

Description of Structure and Explanation of Modelling Decisions

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Chapter One: Document Description

Most energy-economy models, including the model described in this report, have three components: energy supply and production, energy demand, and the consequences of energy production (emissions).

Energy supply constitutes the output of the *energy sector*, and includes the production of both heat and electrical energy. The supply sector typically divides resource extraction and direct use (as *primary energy*) from electricity production and use (as *secondary energy* sources) because electricity "is a major source of fossil fuel CO2 emissions and potentially one of the most important sectors in any emissions mitigation policy response" (Edmonds et al., 2004: 8). A further rationale for separating electric and non-electric energy is given by de Vries et al. (2001: 51), who explain that "Construction of power plants and transmission and distribution networks absorb a sizeable portion of national investments, especially in the early stages of establishing power supplies. Annual investments in electricity generation in the 1990s in the developing countries [were] estimated to be 12% of total domestic investments."

From a modelling perspective, the supply sector includes the electricity-production capacity and its degree of utilization, and the extraction of natural (fossil fuel, and potentially nuclear) resources, in which the issues of resource depletion and saturation are key.[1] Energy resources represented in the model are the three fossil fuels used for heat-production, and electricity used as a secondary energy source. Electricity is modelled as an aggregate, but comes from six principal sources including coal-, oil-, and natural gas-fired plants, alternative electricity production (as a group), nuclear power, and hydroelectric power. The wide array of current and proposed production technologies, each with different costs and benefits and different greenhouse gas emissions levels, makes electricity production the most complicated element of the supply-side.

Energy demand depends on economic-capital requirements, population, and energy prices. In reality, demand is determined by the energy requirements of production capital in the *economic sector*, and is affected by energy prices, conservation policies, carbon taxes, strategic decisions about electricity technology choices, and economic incentives for alternative power generation. Models can either represent all of these various influences on energy demand, or can use some of the more critical factors – and then calculate the quantity of energy demanded as a function of the chosen factors.

In general, demand sectors can be: a) the five sectors for energy use, industrial, commercial, residential, transportation, and *other*, b) the transportation and non-transportation sectors, in which case the energy requirements in the non-transport sector would then be based on the *embodied energy requirements* of economic capital stocks, while the transport sector would focus on gasoline/diesel consumption, or c) a global aggregate demand, which is broken into primary (coal, oil, and natural gas demands), and secondary (aggregate electricity demand) energy sources.

[1] Resource depletion occurs by production (mining or pumping), while saturation signifies the reduction in available sites for alternative energy production or lack of access to mine mouths and loss of oilfield pressure etc. for non-renewable sources.

Finally, the **consequences** of energy production relate to the production of greenhouse gases, as described in Chapter 4, below. As an example, the main sources of carbon dioxide emissions are shown in Figure 1.

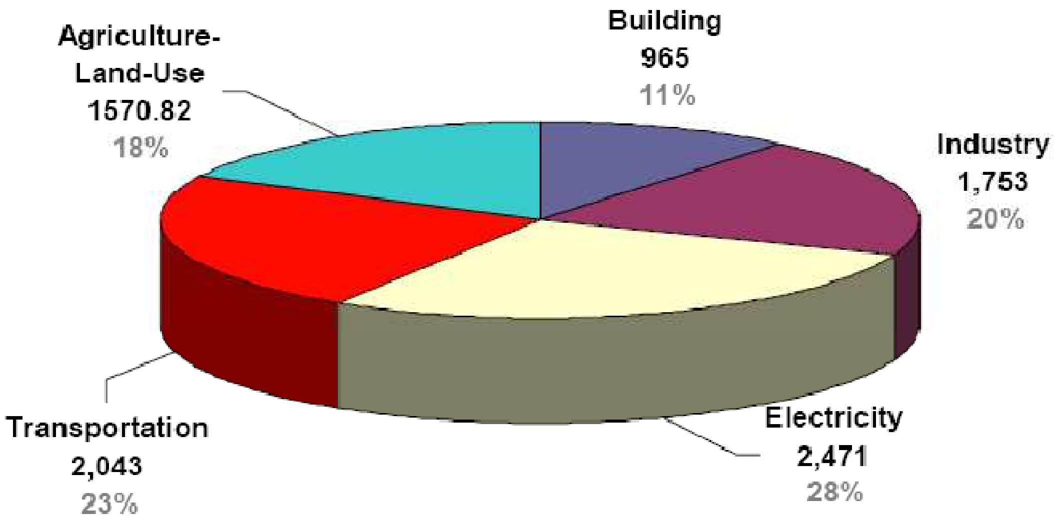


Figure 1: Carbon dioxide emissions by source – probably in Gt yr^{-1} (Figure 3.2 of Edmonds et al., 2004)

1.1 Model Structure

The energy sector has five main components, or "Views" in Vensim's terminology:

1. Energy Demand,
2. Energy Resources,
3. Energy Economics,
4. Energy Production, and,
5. Energy Emissions.

The **Energy Demand** component of the model calculates the net energy demand, which changes over time as a result of economic activity and of price-inspired efficiency measures and technological change. In this component, the net demand is divided into two parts, which represent the heat-energy and electric-energy demands, respectively. Heat-energy demand is further divided in this model component into specific demands for deliveries of quantities of coal, oil, and natural gas resources. Changes in aggregate electricity demand are also modelled here, although electricity production is not divided among competing technologies in this component. Note that historical fossil fuel and electricity production can also be used to drive the energy production of the model, in which case energy demand is treated as an exogenous variable.

Energy Resources contains the non-renewable energy reserves used as primary energy sources and as important inputs to secondary energy production. Remaining amounts of the three fossil fuels represented in the model are tracked in this model component, and can increase through prescribed energy resource *discoveries*, and decrease through production, or *depletion*.

The **Energy Economics** component of the model is perhaps the most complicated of the five. It includes determination of the total investment in the maximum electricity production capacity, which is based both on historical trends and on replacing capacity lost to obsolescence, as well as the division of that total among competing electricity production technologies, which can be based on market forces, in the case of coal-, oil-, and natural gas-fired plants and alternative energy sources, or on the prescriptions of decisions makers, in the case of nuclear and hydroelectric power. Once investment funds are allocated, they flow into an electricity production pipeline, from electricity capacity orders, through construction, and then into installed capacity, which is ultimately removed through retirement. The economics component also includes electricity capital costs and their change over time, fossil fuel production costs and market prices, average energy prices, and electricity production costs and technology market shares.

Energy Production represents the supply portion of the energy sector by producing primary and secondary energy to meet energy demands. Energy is produced from fossil fuel resources both as heat- and electric-energy, and from other electricity production technologies, with electricity production allocated among the competing options according to production costs.

Finally, the **Energy Emissions** component calculates the carbon emissions resulting from the combustion of fossil fuels used to meet energy demands, and from non-energy processes such as cement production and natural gas flaring.

1.1.1 Causal Structure

Because the energy sector is a *system dynamics* model, model structure and the flows of material and information through various feedback loops play key roles in determining simulated behaviour. The two figures below show the causal links in the model that affect its behaviour:

- Figure 2 shows the causal structure of the supply components of the model, while
- Figure 3 displays the basic causal relationships that connect the energy and economic sectors.

All of the causal links depicted in these figures are present in the current version of the energy sector, and their components, underlying assumptions, and associated mathematical expressions are described in detail in this report.

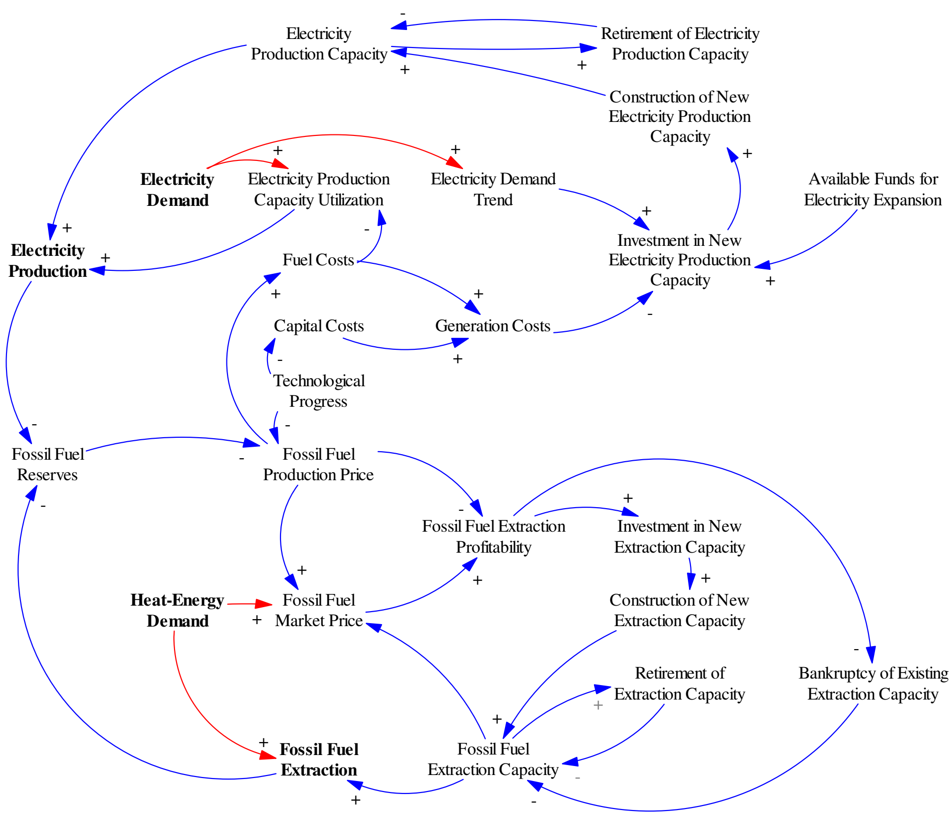


Figure 2: Causal loop diagram for energy production/supply in the model

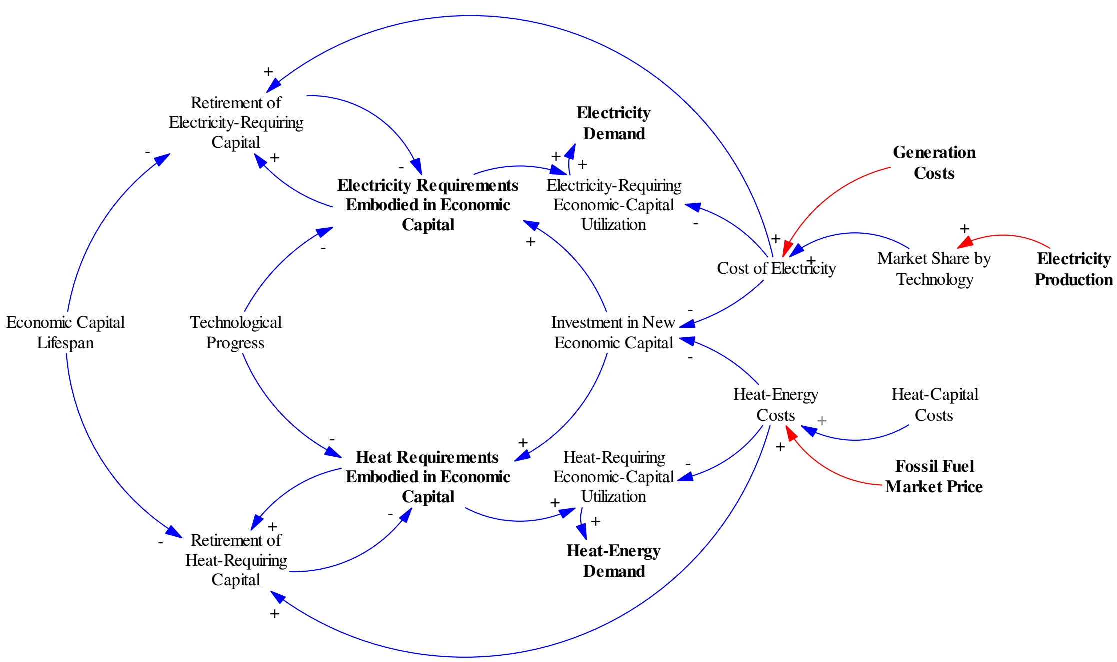


Figure 3: Causal loop diagram of energy supply-demand connections

1.2 Document Order

According to the *energy demand*, *energy supply*, and *energy-use consequences* structure described above, the energy demand "view" takes the role of the *energy demand* component, not surprisingly, while the energy resources and energy production "views" serve as the *energy supply* component. The energy emissions "view" clearly constitutes the *consequences* component, while the energy economics "view" connects energy demand with energy supply.

The first several chapters of this report echo the three-part division described above, with the *energy supply and production* component of the model explained in Chapter 2, the *energy demand* component in Chapter 3, and the *energy-use consequences* component in Chapter 4. Details of the economic structure are distributed throughout the report, with economic variables playing key roles in determining both the energy produced and the quantities of energy demanded. Technological change is currently modelled implicitly, and simply, as explained in Chapter 5; an endogenous approach towards technology change would improve the model.

The initial version of the model (as described in Chapters 2-5) has a start-date of 1980 to match the availability of energy data from the majority of available sources, while the larger society-biosphere-climate model – see Davies (2007) and Davies and Simonovic (2008) – to which the energy sector is coupled uses a start date of 1960. It was therefore necessary to recalibrate the energy sector for a start date of 1960; this recalibration and the integration of the energy sector into the full model are the subjects of Chapter 6.

Finally, Chapter 7 describes the economic limitations of the current energy model, and provides a list of model areas and variables that may benefit from additional attention. Furthermore, Chapter 7 explains the sorts of policies that the model can simulate and the kinds of model changes that may lead to a larger number of alternative-policy representations.

The four appendices provide a full listing of all model equations (Appendix A), describe alternative methods towards modelling electricity production capacity (Appendix B) and fuel prices (Appendix C) based on the FREE model (Fiddaman, 1997), and list and explain the energy demand model from the COAL2 model (Appendix D) developed by Naill (1977).

1.2.1 Files Associated with the Model

Please note that the Vensim model described here is available in three forms:

1. Energy Sector – 1980 Start.mdl
2. Energy Sector – 1960 Start.mdl
3. Modified Danube-DICE with Energy Sector.mdl

The first model is the version described in Chapters 2-5, while the second model is the recalibrated version described in Chapter 6. Finally, the third model is the complete society-biosphere-climate model including the new, recalibrated energy sector, also described in Chapter 6. All three models are programmed in the Vensim *system dynamics* software package, and require Vensim DSS to operate.

Furthermore, several Microsoft Excel files provide data used to set up the model. The report refers to these files where appropriate, but as an additional resource for interested readers, the important files and their contents are,

1. *Emissions Calculations*, which contains calculations that translate non-energy use (through cement production and natural gas flaring) into carbon emissions, based on data from Marland et al. (2008);
2. *Energy-Capital Calculations*, which provides data on existing electricity generation capacity, capital costs, and historical investment into same. It also calculates the regional distribution of existing capacity;
3. *Energy Reserves*, which provides global aggregate energy reserve, production, and discovery data and related calculations, as well as a determination of the energy contents of the three fossil fuels. The file also compares the available IEA and EIA data; and,
4. *Historical Energy Consumption – IEA Values*, which contains information on the total primary energy supply (TPES), as well as coal, oil, natural gas production. Values are listed for both OECD and non-OECD countries, and a calculation of energy use per unit GDP is also given.

Chapter Two: Energy Supply

This chapter describes the energy supply and production components of the model, as well as the underlying economic variables that affect them. The chapter begins with a summary of real-world energy resource, extraction, and electricity production data, which provide a means of validating model performance (1).

The next sections of the chapter review other existing energy-economy models, and then develop and explain the model approach chosen here. Primary energy – energy reserves and extractive processes – is the first topic (2), followed by secondary energy capacity and production (3).

The chapter concludes with preliminary model results (4).

1. Real-World Energy Data

This section serves as a **data source** for the purpose of model cross-checking. It documents energy resource supply, extraction and heat contents (1.1)[2], general energy use and specific electricity production capacity and actual production (1.2). I separate non-electrical from electrical production as do a variety of energy-related publications and models (IEA, 2007d; de Vries and Janssen, 1997; de Vries et al., 1994). The energy sector therefore deals separately with *heat* and *electricity*.

1.1 Energy Resource Supply and Extraction

Energy supply is the basis of energy production, particularly in terms of fossil fuel resources. This section documents remaining energy reserves (1.1.1), cumulative energy extraction (1.1.2) – i.e. the amount of the resource already used – and the heat content of the various fossil fuels, which determines how much resource is required for thermal energy production (1.1.3).

1.1.1 Historical Energy Reserves

Extracted energy sources include coal, oil, natural gas, and uranium. *Reserves* are not *resources*: "*Reserves* are the amount currently technologically and economically recoverable. *Resources* are detected quantities that cannot be profitably recovered with current technology, but might be recoverable in the future, as well as those quantities that are geologically possible but yet to be found" (World Energy Council, 2007: 41). Saturation effects (Fiddaman, 1997) are also important in terms of alternative energy sources, and hydro power in particular.

The total ***volumes/masses of recoverable non-renewable energy sources*** are given below:

- **Coal:**
    - The EIA (2006) provides spreadsheets of energy reserves. The following data is from Table 8.2, "World Estimated Recoverable Coal", under the *coal > reserves* section at

[2] This is the notation that will be used throughout the paper to indicate references to particular sections of the document. Page numbers for each section are listed at the beginning of the paper in the *table of contents*.

http://www.eia.doe.gov/emeu/international/contents.html, accessed July 4, 2008. The data is accurate as of June 2007. Total recoverable anthracite and bituminous coal is 528 772 million short tons[3], total recoverable lignite and sub-bituminous is 468 976 million short tons, and so the total recoverable coal is *997 748 million short tons*.
  - The IEA (2007a), Table I.3, gives a total proved, recoverable resource in 2005-6 of 934 877 Mt. The masses of recoverable hard and soft coal are listed as 727 484 Mt and 207 393 Mt.
  - The World Energy Council (WEC, 2007) has relatively long write-ups on every major energy source of interest. Table 1.1 (WEC, 2007: 11) lists the following masses of *proved, recoverable* coal as of year-end 2005: 430 896 million tonnes of bituminous coal, 266 837 million tonnes of sub-bituminous coal, and 149 755 million tonnes of lignite, for a total proved, recoverable reserve of *847 488 million tonnes*. Because of extensive exploration, coal reserves are believed to be quite well known, although slight revisions of numbers do occur.
  - The German Federal Institute for Geosciences and Natural Resources (BGR) produces an annual energy resources publication, with the 2006 edition available in English (Rempel et al., 2006). According to Table 1 of the report (Pg. 5), total coal *reserves* in 2005 and 2006 were 697 and 726 Gt SKE[4] or 20 408 and 21 286 EJ (Table 2), respectively. *Resources* are considerably higher, at 3917 and 8710 Gt SKE or 114 758 and 255 194 EJ (Table 2), respectively.
- **Oil:**
  - The USGS (2000) conducted a survey of world petroleum reserves, which is cited by the EIA under the title "International Petroleum (Oil) Reserves and Resources". They estimate a global *conventional* reserve volume[5] of 3021 BBOE (billions of barrels of oil-equivalent), of which 710 BBOE has already been produced. Of the total, the *reserve growth* from discovered resources is (a mean of) 688 BBOE, and *undiscovered reserves* may amount to (a mean of) 732 BBOE. In other words, the *proven reserves* are 891 BBOE.
  - The EIA (2006) provides spreadsheets of energy reserves.
    - The following data is from the spreadsheet "World Proved Crude Oil Reserves, January 1, 1980 - January 1, 2008 Estimates" at www.eia.doe.gov/emeu/international/oilreserves.html, accessed July 4, 2008. Note that Canada, in particular, has considerably larger reserves now than in 1980 because of the inclusion of the tar sands in the tally, as of 2003. The top line is the year; the bottom line is the crude oil reserve in billions of barrels (BB).

1980	1985	1990	1995	2000	2005	2006	2007	2008
644.93	699.81	1002.2	999.26	1016.8	1277.2	1292.9	1316.7	1331.7

[3] Conversion factor: one metric ton(ne) is 1.10231136 short tons (EIA, 2006).
[4] I am not sure what SKE denotes. Rempel et al. (2006) state that this is a common unit, but I have not been able to find reference to it elsewhere – it may be the acronym assigned to coal mass in German.
[5] In other words, not including tar sands and the like. The term "conventional" excludes oil from shale, shale, bitumen, and *extra-heavy oil* (World Energy Council, 2007).

        - A second set of data comes from two energy resource journals, *Oil and Gas Journal* and *World Oil*, which are cited by the EIA in Table 8.1, "World Crude Oil and Natural Gas Reserves, January 1, 2006" at http://www.eia.doe.gov/emeu/international/oilreserves.html, accessed July 4, 2008. The two values are, respectively, 1292.9 BB and 1119.6 BB
    - The World Energy Council (WEC, 2007: 54) explains the reserve/resource terminology quite clearly. *Proved, recoverable reserves* at end-2005 are given as 159 644 million tonnes [metric], or 1215.2 billion barrels.
    - The German Federal Institute for Geosciences and Natural Resources (BGR) study (Rempel et al., 2006) gives values for *oil reserves* in Tables 1 and 2 (Pg. 5 and 6) of 162 and 163 Gt or 6792 and 6805 EJ in 2005 and 2006, respectively. *Resource* amounts are given as 82 and 82 Gt or 3430 and 3430 EJ in 2005 and 2006, respectively.
    - The Society of Danish Engineers (2003) published a discussion paper on peak oil in which they quote a series of papers and studies on oil production, use, and reserves. One study cited in the paper is by Jean Laherrere (Pg. 53), who estimates ultimate reserves of conventional crude oil and natural gas liquids amount to 2000 billion barrels of oil, of which a considerable volume has already been extracted. A second study by Colin J. Campbell (Pg. 54) says that past production amounted to 873 billion barrels of oil and that reserves now amount to 884 billion barrels (as of 2002). Campbell estimates that new fields may contain 144 billion barrels.
- **Natural Gas:**
    - The USGS (2000) world petroleum reserve survey also includes natural gas figures. They report a global natural gas *undiscovered conventional resource* volume of 5196.4 trillion cubic feet, *reserve growth (potential)* of 3660 trillion cubic feet, and *remaining reserves* of 4793 trillion cubic feet. *Cumulative production* is given as 1752 trillion cubic feet.
    - The EIA (2006) provides gas reserve figures in two spreadsheets
        - The "World Proved Natural Gas Reserves, January 1, 1980 - January 1, 2008 Estimates" spreadsheet gives the following figures, where the top line is the year, while the bottom line is the natural gas volume in trillions of cubic feet.

1980	1985	1990	1995	2000	2005	2006	2007	2008
2580.2	3401.5	3991.2	4981.7	5149.6	6046.1	6124.0	6189.4	6185.7

        - A second set of data comes from two energy resource journals, *Oil and Gas Journal* and *World Oil*, which are cited by the EIA in Table 8.1, "World Crude Oil and Natural Gas Reserves, January 1, 2006" at http://www.eia.doe.gov/emeu/international/oilreserves.html, accessed July 4, 2008. The two values are, respectively, 6124.0 trillion cubic feet and 6226.6 trillion cubic feet.
    - The World Energy Council (WEC, 2007: 146) states that "proven world natural gas reserves have grown at an annual average of 3.4% since 1980 … due to an impressive string of gas exploration successes and better assessments of existing fields. Hence the volume of proven gas reserves more than doubled over the period…" The *proved, recoverable reserves* of natural gas at end-2005 are 176 462 billion cubic meters, or 6231.7 trillion cubic feet.

- The German Federal Institute for Geosciences and Natural Resources (BGR) study (Rempel et al., 2006) gives values for *natural gas reserves* in Tables 1 and 2 (Pg. 5 and 6) of 180 and 181 trillion m^3 or 6845 and 6891 EJ in 2005 and 2006, respectively. *Resource* amounts are given as 207 and 207 trillion m^3 or 7866 and 7866 EJ in 2005 and 2006, respectively.

- **Uranium:**
  - The World Energy Council (WEC, 2007: 209) lists *recoverable uranium reserves* by uranium prices. Thus, more uranium is recoverable at higher uranium prices. At prices of less than \$40 kg^{-1} of uranium, up to 1947.4 thousand tonnes are recoverable, while at up to \$130 kg^{-1}, 3296.7 thousand tonnes are recoverable. Furthermore, *inferred resources* are 799.0 thousand tonnes at less than \$40 kg^{-1} and 1446.2 thousand tonnes at up to \$130 kg^{-1}, while *undiscovered resources* are 4557.3 thousand tonnes at up to \$130 kg^{-1}, with a total resource (where price is not an issue) of 7535.9 thousand tonnes.
  - The German Federal Institute for Geosciences and Natural Resources (BGR) study (Rempel et al., 2006) gives values for *uranium reserves* in Tables 1 and 2 (Pg. 5 and 6) of 1.95 Mt U or 799 EJ for prices of less than \$40 kg^{-1}, and *uranium resource* amounts of 5.32 Mt U or 2180 EJ for *recoverable resources* in the price range of \$40-130 kg^{-1}plus inferred resources, and finally of 7.54 Mt U or 3091 EJ for *speculative resource* amounts.
  - The EIA (2006) does not offer uranium reserve values.
- **Hydropower:**
  - The World Energy Council (WEC, 2007: 283) lists the gross theoretical capability for hydropower production as 41 202 TWh yr^{-1} or greater, and the technically exploitable capability as 16 494 TWh yr^{-1}.
  - The EIA (2006) does not offer potential hydroelectric development figures.

1.1.2 Historical Energy Reserve Extraction

Annual non-renewable ***energy extraction masses/volumes*** are provided below:

- **Coal:**
  - The EIA (2006) provides coal production figures on the spreadsheet called "World Coal Production, Most Recent Annual Estimates, 1980-2007". The figures are provided in the table below, with the year on the top line and the production value on the bottom line, in million short tons (see footnote 3).

1980	1985	1990	1995	2000	2005	2006	2007	2008
4188.0	4895.5	5353.9	5105.0	4949.5	6492.1	6795.6	7036.3	N/A

  - The IEA (2007a) also provides detailed information about coal production and consumption, dating back to 1973 for both OECD and Non-OECD countries. Data are available all the way back to 1960 on the online version of the resource, at http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=302 (accessed Jan 28, 2009); however, this database is available only to subscribing institutions, and UWO does not subscribe.

- According to the World Energy Council (WEC, 2007: 18), a total of 5901.5 million tonnes of coal was mined in 2005.
- The German Federal Institute for Geosciences and Natural Resources (BGR) (Rempel et al., 2006: 10) states that 141.5 EJ of coal was produced world-wide in 2006.

- **Oil:**
  - The EIA (2006) provides crude oil extraction figures on the spreadsheet called "World Production of Crude Oil, NGPL, and Other Liquids, and Refinery Processing Gain, Most Recent Annual Estimates, 1980-2007" – the title is indicative of the basis of the values. The figures are provided in the table below, with the year on the top line and the production value on the bottom line, in millions of barrels per day.

1980	1985	1990	1995	2000	2005	2006	2007	2008
63.987	59.172	66.425	70.272	77.762	84.631	84.597	84.601	N/A

  - The IEA (2008b) also provides detailed information about oil production and consumption, dating back to 1973 for both OECD and Non-OECD countries. Data are available all the way back to 1960 on the online version of the resource, at http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=301 (accessed Jan 28, 2009); however, this database is available only to subscribing institutions, and UWO does not subscribe.
  - According to the World Energy Council (WEC, 2007: 63), a total of 3579.6 million tonnes of oil was produced in 2005, which works out to 71 745 thousand barrels per day.
  - The German Federal Institute for Geosciences and Natural Resources (BGR) (Rempel et al., 2006: 10) states that 163.7 EJ of crude oil was produced world-wide in 2006.

- **Natural Gas:**
  - The EIA (2006) provides dry natural gas production values in Table 2.4, "World Dry Natural Gas Production, 1980-2005". The figures are provided in the table below, with the year on the top line and the production value on the bottom line, in trillion cubic feet.

1980	1985	1990	1995	2000	2005	2006	2007	2008
53.35	62.39	73.57	77.96	88.30	101.53	N/A	N/A	N/A

    A second EIA (2006) source, Table 4.1, "World Natural Gas Production, 2004" provides figures on re-injection, and venting/flaring for 2004 of 2741 billion cubic feet and 13 602 billion cubic feet, respectively, for a *gross production* of 120 345 billion cubic feet and a *net production* of 98 530 billion cubic feet.
  - The IEA (2007e) also provides detailed information about oil production and consumption, dating back to 1973 for both OECD and Non-OECD countries. Data are available all the way back to 1960 on the online version of the resource, at http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=303 (accessed Jan 28, 2009); however, this database is available only to subscribing institutions, and UWO does not subscribe.

- According to the World Energy Council (WEC, 2007: 166), a total of 3540.7 billion cubic meters of natural gas were produced in 2005, of which 414.9 billion cubic meters were re-injected, 118.1 billion cubic meters were flared, and 173.8 billion cubic meters were lost to 'shrinkage' (due to the extraction of natural gas liquids, etc.), leaving a net production of 2833.9 billion cubic meters, or 100.1 trillion cubic feet.
- The German Federal Institute for Geosciences and Natural Resources (BGR) (Rempel et al., 2006: 10) states that 111.2 EJ of natural gas was produced world-wide in 2006.

- **Uranium:**
  - According to the World Energy Council (WEC, 2007: 215), a total of 41 699 tonnes of uranium were produced in 2005, with a cumulative production to end-2005 of 2 286 729 tonnes.
  - The German Federal Institute for Geosciences and Natural Resources (BGR) (Rempel et al., 2006: 10) states that 16.4 EJ of uranium was produced world-wide in 2006.

For the model, initial reserve volumes/masses for the fossil fuels have been calculated (coal) or assigned (oil and natural gas) in an **MS Excel database** called "Energy Reserves". The values used are in metric units (coal, natural gas) or in common units (oil) and correspond to the year 1980[6]:

- **Coal**: 905141 million metric tonnes
- **Oil**: 644.93 billion barrels of oil
- **Natural Gas**: 73.06 trillion m^3

In the case of coal, the World Energy Council (WEC, 2007) explains that coal reserves are quite well-known after centuries of exploration.[7] The same is not the case for petroleum and natural gas reserves, which have actually grown quite considerably from 1980 onwards. For petroleum, the reserve values are now estimated at 1331.7 BB of oil (2008 figures from EIA, 2006), while proved natural gas reserves in 2008 are 6185.7×10^9 ft^3, or 175.16 trillion m^3 (EIA, 2006).

1.1.3 Conversion of Reserve Units to Heat Units

These reserve values are only really useful if they are converted into energy units, to match them to energy production, and possibly to carbon content units for translation into emissions levels:

- **Coal:**
  - Rempel et al. (2006) says 1 tonne of coal contains 29.308 GJ of energy on average, but the conversion is not explained clearly and is very different from the values obtained from EIA (2006) sources;
  - Conversion factors from the EIA (2006) yield very different energy contents for coal. Coal energy content differs by coal type: anthracite and bituminous coal have higher energy contents than lignite. According to calculations performed in the "Energy Reserves" Excel file, the energy content of *produced* coal has risen slightly over time, from 1980-2005, most likely because of the use of more energy-rich coal resources. The values calculated are provided in the table below, in (GJ/t):

[6] Back-calculations will be necessary when the model is reset to 1960.
[7] However, the BGR (Rempel et al., 2006: 19) states exactly the opposite, because of new data from China and the CIS-countries (Russia). It is therefore not clear which publication is right…

1980	1985	1990	1995	2000	2005
19.981	19.983	20.061	21.070	22.926	23.255

These values are calculated from EIA (2006) coal production figures and from their coal heat content figures.
Calculation method: The average global coal heat content value was calculated from coal production masses for the top seven coal producing nations, which accounted for 75-80% of global production, and their national-average coal heat-content values (thousands of Btu per short ton). The imperial units were then translated into metric units using two conversion factors: 1 tonne = 1.10231136 short tons, and 1 Btu = 1055.056 J. There is some difference between the energy of coal production (EJ) figures given by the EIA (2006) in Table f.5 and calculated using the figures above, but the error is less than 7.5% for all years in the table above, and less than 5% for four of the six periods.

- **Oil:**
  - Rempel et al. (2006) says 1 ton of oil-equivalent is equal to 1.428 tons of coal-equivalent, but, again, the conversion is not explained clearly and is very different from the values obtained from EIA (2006) sources.
  - Conversion factors from the EIA (2006) yield a mixture of metric and imperial units – the volume component is measured in barrels (1 B = 159 L), while the energy component is measured in Joules. The energy content of a barrel of oil is relatively constant compared with the energy content of coal, according to calculations in the "Energy Reserves" Excel file discussed above. The values provided in the table below are in (MJ/barrel):

1980	1985	1990	1995	2000	2005
6227	6201	6205	6195	6199	6205

These values are calculated from EIA (2006) oil production figures and from their oil heat content figures.
Calculation method: The average global oil heat content value was calculated from oil production volumes for the top ten crude oil producing nations, which accounted for 60-75% of global production – oil production is much more diffuse than coal production – and their national-average oil heat-content values (thousands of Btu per barrel). The imperial units were then translated into metric units using the conversion factor 1 Btu = 1055.056 J. There is very little difference between the energy of coal production (EJ) figures given by the EIA (2006) in Table f.2 and calculated using the figures above: the error is less than 0.5% for all years in the table above.

- **Natural gas:**
  - According to calculations in the "Energy Reserves" Excel file discussed above, conversion factors from the EIA (2006) yield the following energy content for a cubic meter of natural gas, in (MJ m^{-3})

1980	1985	1990	1995	2000	2005
38.07	38.29	38.26	38.06	38.36	38.54

These values are calculated from EIA (2006) natural gas production figures and from their natural gas heat content figures. Note that gross production is roughly 20% higher than dry gas production, since some of the gross production is flared, vented, or reinjected (the majority).

Calculation method: The average global natural gas heat content value was calculated from dry natural gas production volumes for the top natural gas producing nations, which accounted for 65-80% of global production – natural gas production is much more diffuse than coal production – and their national-average natural gas heat-content values (Btu per cubic foot). The imperial units were then translated into metric units using the conversion factors 1 m^3 = 35.3146667 ft^3 and 1 Btu = 1055.056 J. There is very little difference between the energy of natural gas production (EJ) figures given by the EIA (2006) in Table f.4 and calculated using the figures above: the error is less than 0.8% for all years in the table above.

1.2 Energy Use and Production

This section describes energy use and production in general (1.2.1), and then provides specific data on electricity production and capacity (1.2.2), and on specific electricity-producing capital characteristics including lifetimes, construction delays, and capital costs (1.2.3).

As an introduction to the topics in this section, Figure 4 (IEA, 2005: I.83) shows the global growth in total energy production and electricity production.

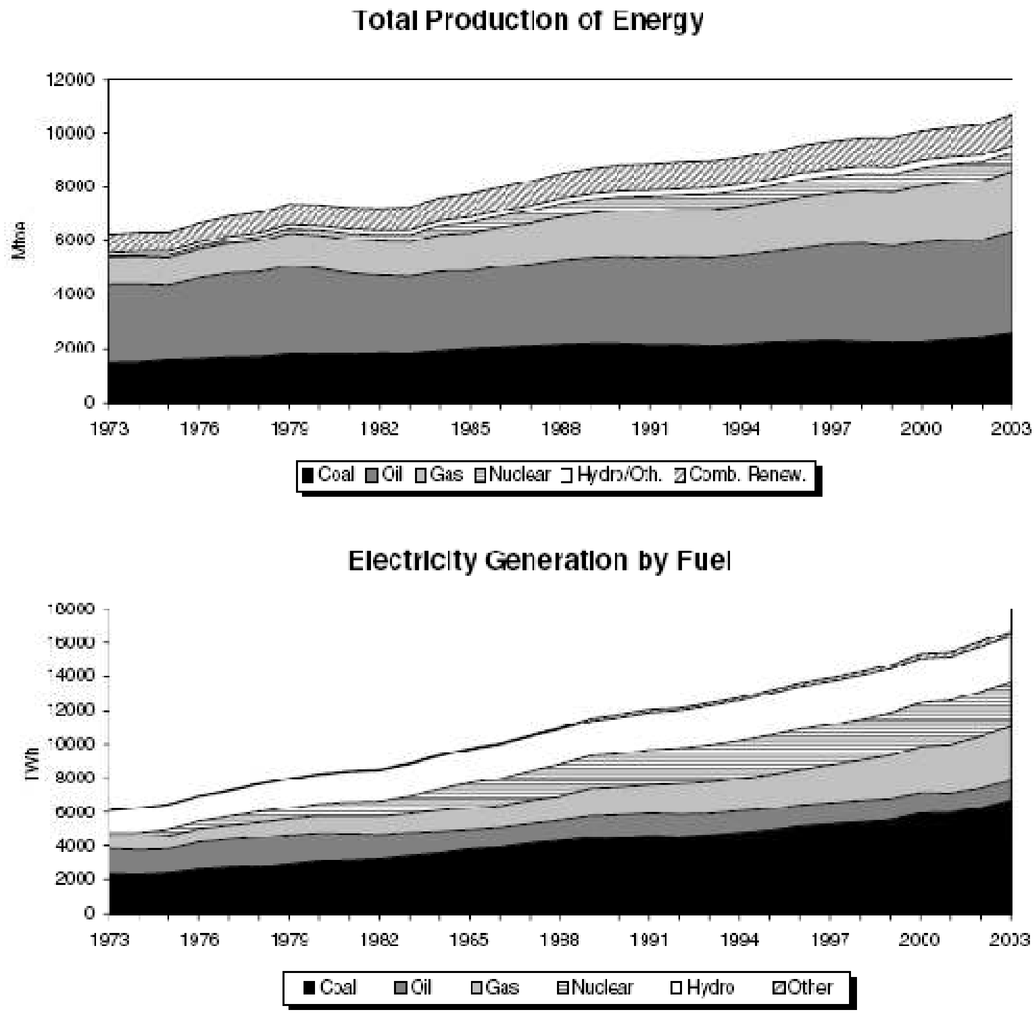


Figure 4: Total global production of energy and electricity production by fuel (from IEA, 2005)

1.2.1 Energy Use Data

Each of five **energy demand** sectors – industrial, residential, commercial, transportation, and other – consume energy for different purposes (IEA, 2008c):

- ***Industry***: 33% of total global energy consumption:
  - Share of **non-electricity**:
    - Share of oil was 13% (2004), down from 15% (1990) (IEA, 2007d: 47);
    - Share of coal 19% (2004), down from 25% (1990) (*ibid.*);
    - Share of natural gas 29% (2004), up from 27% (1990) (*ibid.*); and,
  - Share of **electricity**: 27% (2004), up from 24% (1990) (*ibid.*).
  - Most industrial energy use is for production of raw materials (67% of total). Food production, tobacco, machinery and other industries account for the other 33% (IEA, 2007f: 39);
    - Primary metal production (iron, steel, aluminum, etc.) consumes the largest share of total energy in manufacturing (24%), followed by chemicals (19%), and paper and pulp (17%) (IEA, 2007d: 47);

        - Rough estimates: 15% of total energy demand in industry for feedstock, 20% for process energy at temperatures above 400°C, 15% for motor drive systems, 15% for steam at 100-400°C, 15% for low-temperature heat, and 20% for other uses, such as lighting and transport (IEA, 2007f: 41).
    - Total manufacturing energy use in the IEA19 increased by 3% between 1990 and 2004 (IEA, 2007d: 47);
- ***Residential***: 29% of total global energy consumption:
    - Energy uses: space heating (53%), appliances (21%), water heating (16%), lighting (5%), and cooking (5%) in OECD countries (IEA, 2008c);
    - Between 1990 and 2004, total final energy use rose by 14% in 15 IEA countries (IEA, 2008c);
    - Since 1990, electricity consumption in households increased by 35%; natural gas use rose by 23% in OECD (IEA, 2008c);
- ***Transport***: 26% of total global energy consumption:
    - Between 1990 and 2004, global total final energy use rose by 37%. Road transport accounts for 89% of total, with increase of 41% (IEA, 2008c);
    - In 18 IEA countries, passenger transport: 87% by car, and 99% of energy provided by oil; Freight transport is 82% by truck, and 99% of energy provided by oil (IEA, 2008c);
- ***Commercial***: 9% of total global energy consumption:
    - Commercial activities include trade, finance, real estate, public administration, health, education, and commercial services
    - 73% of total energy use is in OECD countries, but energy use in non-OECD countries is growing fast – more than 50% from 1990 to 2004 (IEA, 2008c);
    - Global increase in services sector energy use is 37% from 1990-2004 (IEA, 2008c);
    - Most of reliance is on electricity (47%) and natural gas, but oil important in some regions (OECD-Pacific). Increase in electricity use is 73% since 1990 (IEA, 2008c);
- ***Other***: 3% of total global energy consumption;

See also IEA (2007b) and (2007c) for historical global and regional energy use statistics.

1.2.2 Electricity Production and Capacity Data

This section provides global data on electricity-production *capacity* (GW; 1.2.2.1), and on actual *production* (GJ yr^{-1} or TWh yr^{-1}; 1.2.2.2) by electricity-production technology.

Electricity production represents 22% of total energy use in the IEA countries, and is the second-most important energy source after oil (natural gas is third) (IEA, 2007d: 25). Globally, electricity production also represents 32% of the total use of *fossil fuels* and is the source of 41% of the energy-related carbon dioxide emissions. Fossil fuels are the source of 66% of public electricity production (IEA, 2008c), while hydro plants provided 16.3%, nuclear plants 15.7%, combustible renewables and waste 1.2%, and geothermal, solar, wind, etc. 0.8% (IEA, 2005).

- In OECD countries, total combustible fuel plants accounted for 62.7% (made up of 61.0% from fossil-fuel-fired plants and 1.7% from combustible renewables and waste plants) of total gross electricity production in 2004, Nuclear plants 22.9%, hydroelectric plants 13.3%, and geothermal, solar and wind plants 1.1% (IEA, 2005: I.3); and,

- In non-OECD countries, 72.9% of the total came from combustible fuels (consisting of 72.4% of fossil fuel generation and 0.5% of combustible renewables and waste generation). Hydro provided 20.7% of production, nuclear plants provided 6.1% of production and geothermal, solar, wind, etc. provided the remainder (IEA, 2005: I.10).

Efficiency of fuel conversion to electricity is also an important factor in energy use; efficiencies have improved over time. According to the IEA (2008c: 71), "The global average efficiencies of electricity production are 34% for coal, 40% for natural gas and 37% for oil. For all fossil fuels, the global average efficiency is 36%. Wide variations are seen in efficiencies amongst countries, with OECD countries typically having the highest efficiencies. The level of efficiency has been slowly improving in recent years in most countries.

1.2.2.1 Electricity Production Capacity

The EIA (2006) provides electricity production capacity statistics for the whole world, by country and region, in Table 6.4, "World Total Electricity Installed Capacity, January 1, 1980 - January 1, 2005". Other sources include:

- Table 6.4t, "World Conventional Thermal Electricity Installed Capacity, January 1, 1980 - January 1, 2005", is for thermal power plants – coal, oil, and natural gas;
- Table 6.4h, "World Hydroelectricity Installed Capacity, January 1, 1980 - January 1, 2005", is for hydroelectric capacity;
- Table 6.4n, "World Nuclear Electricity Installed Capacity, January 1, 1980 - January 1, 2005", is for nuclear capacity;
- Table 6.4g, "World Geothermal, Solar, Wind, and Wood and Waste Electricity Installed Capacity, January 1, 1980 - January 1, 2005", is for the alternative energy capacity.

Table 1, below, combines the data in the EIA tables.

Table 1: Global installed electricity-production capacity (GW)

Year	1980	1985	1990	1995	2000	2001	2002	2003	2004	2005
Global Cap.	1945.6	2315.4	2658.3	2929.3	3279.3	3392.3	3512.3	3638.9	3748.4	3872.0
Thermal Cap.	1347.8	1542.5	1737.6	1929.6	2195.5	2285.9	2387.6	2485.8	2569.9	2652.3
Hydro Cap.	457.2	527.2	575.4	625.0	683.3	695.9	706.8	720.3	739.0	761.9
Nuclear Cap.	135.5	236.8	323.1	346.9	358.3	361.4	361.6	368.5	368.2	374.2
Alt. E. Cap.	5.0	8.9	22.1	27.8	42.3	49.1	56.3	64.3	71.2	83.6

Global nuclear capacities and construction starts are reported from 1954 onward in IAEA (2008).

OECD countries reported a total *installed electricity capacity* in 2003 of 2352 GW: 1574 GW of plants fired by fossil and other combustible fuels, 313 GW nuclear power, 421 GW hydroelectric power (including pumped storage capacity) and 43 GW of solar, wind, geothermal and tide/wave/ocean capacity (IEA, 2005: I.5).

Table 11 (Pg. I.55) of the same IEA publication provides the OECD-nations' growth in net maximum electricity capacity values (in GW) since 1974 for each fuel type, including their associated production technologies. Table 11 has been reproduced below as Table 2:

Table 2: Maximum electricity-production capacity for OECD nations (GW)

	1974	1985	1990	2000	2002	2003	Average annual percent change 74-90	90-03
Total(1)	**993.32**	**1530.87**	**1700.04 e**	**2057.28 e**	**2269.93 e**	**2351.58 e**	**3.4**	**2.5**
Nuclear	52.92	205.05	265.03	302.09	314.09	313.14	10.6	1.3
Hydro	178.80	341.30	369.18 e	420.25 e	421.04 e	421.32 e	4.6	1.0
of which: Pumped Storage	*..*	*32.43*	*44.04*	*84.93 e*	*83.45*	*82.42 e*	*..*	*4.9*
Geothermal	0.64	2.86	4.46	5.39	5.72 e	5.88	12.9	2.1
Solar	-	0.02	0.35	0.81	0.87 e	1.04 e	-	8.8
Tide, Wave, Ocean	0.24	0.26	0.26	0.26 e	0.26	0.26	0.5	-
Wind	-	0.06	2.39	15.42	28.39	35.44 e	-	23.1
Other (e.g. Fuel cells)	-	-	-	0.30	0.25	0.37 e	-	-
Combustible Fuels	760.72	981.32	1058.36	1312.76	1499.31 e	1574.13 e	2.1	3.1
of which:								
Single fuel fired:								
Coal and Coal Products	316.00	396.12	436.75	508.17 e	471.38 e	487.84 e	2.0	0.9
Liquid Fuels	226.49	217.41	194.46	163.55 e	147.80 e	148.49 e	-0.9	-2.1
Natural Gas	74.58	43.46	76.01	219.50 e	322.63 e	376.27 e	0.1	13.1
Comb. Renew. & Waste	0.16	2.89	10.07	17.38 e	17.37 e	21.85 e	29.5	6.1
Multi-fired:								
Solid / Liquid	43.31	86.73	85.94	73.96 e	62.62 e	62.31 e	4.4	-2.4
Solid / Natural Gas	17.96	30.98	34.49	9.72 e	4.26 e	4.35 e	4.2	-14.7
Liquid / Natural Gas	68.16	186.77	175.84	217.79 e	239.89 e	262.12 e	6.1	3.1
Solid / Liquid / Gas	9.29	16.96	17.87	18.31 e	11.63 e	11.63 e	4.2	-3.3

Source: IEA/OECD Electricity Statistics.

For the IEA countries[8], Table 16 (Pg. I.60) – reproduced here as Table 3 – provides the totals for each fuel type:

Table 3: Installed electricity-production capacity for IEA nations (GW)

Year	1974	1990	2000	2003
Electricity from Coal	368.7	547.9	579.1	530.9
Electricity from Oil	225.0	180.1	151.5	137.7
Electricity from Natural Gas	142.7	248.4	423.3	614.8
Electricity from Combined Renewables and Waste	0.16	10.07	17.37	21.82
Hydroelectricity	174.5	359.3	406.0	406.9
Nuclear Power Generation	52.9	264.4	298.1	309.1
Geothermal/Solar/Wind, others	0.81	6.76	21.31	41.97
Total	964.8	1643.8	1978.8	2262.4

[8] The IEA and OECD are closely related, but the OECD has more member countries (and hence more installed electrical capacity).

1.2.2.2 Annual Electricity Production

An IEA report called *Electricity Information* (IEA, 2005) contains detailed figures on electricity production within OECD countries and the IEA. However, the majority of global figures it provides are given in brief descriptions, such as in this statement,

> Between 1973 and 2003, world electricity production has increased from 6124 TWh to 16742 TWh. The average annual growth rate during that time span is 3.4%. In 1973, 72.9% of electricity production was in countries that are currently members of the OECD. In 2003, 59.4% of electricity production was in OECD countries (IEA, 2005: I.3).

Basic electricity statistics (in TWh) are provided in Table 2 of IEA (2005: I.32) and are duplicated below as Table 4 – note particularly the losses and their types.

Table 4: Basic electricity statistics for OECD and non-OECD nations (TWh)

	Gross Produc-tion (1)	Imports	Exports	Own Use	Other Use (2)	Supply	Transm. Losses(3)	Energy Sector (4)	Final Consu-mption
OECD Total	9938.3	371.9	353.5	458.7	101.8	9396.2	669.8	253.4	8472.9
Non-OECD Total	6803.6	172.9	194.9	433.6	11.6	6336.4	845.0	299.7	5191.7
World	**16741.9**	**544.8**	**548.4**	**892.3**	**113.4**	**15732.6**	**1514.8**	**553.1**	**13664.6**

The U.S. EIA (2006) provides similar global total electricity production figures (TWh) in Table 6.3, "World Total Net[9] Electricity Generation, 1980-2005", which are reproduced in Table 5 below. Other sources for the table below include:

- Table 6.1, "World Net Conventional Thermal Electricity Generation, 1980-2005", for thermal energy sources;
- Table 2.6, "World Net Hydroelectric Power Generation, 1980-2005"
- Table 2.7, "World Net Nuclear Electric Power Generation, 1980-2005"
- Table 2.8, "World Net Geothermal, Solar, Wind, and Wood and Waste Electric Power Generation, 1980-2005"

Table 5: Global electricity production figures by energy source (TWh)

Year	1980	1985	1990	1995	2000	2001	2002	2003	2004	2005
Global Prod.	8026.9	9477.1	11323	12625	14619	14825	15376	15918	16650	17351
Thermal	5588.5	6041.1	7137.9	7785.1	9281.3	9504.3	9949.6	10476	10935	11455
Hydro Prod.	1722.9	1954.9	2148.9	2457.3	2645.4	2550.7	2596.8	2616.0	2759.2	2900.0
Nuclear Prod	684.4	1425.4	1908.8	2210.0	2449.9	2516.7	2545.3	2517.8	2615.0	2625.6
Alt. E. Prod.	31.1	55.5	127.1	172.2	242.6	253.0	284.5	308.2	341.5	369.7

Total electricity production figures (in TWh) for OECD countries are given by country and fuel in Table 3. Non-OECD figures on gross electricity production are imperfect, but are provided in the same format in Table 6. World gross electricity production totals (in TWh) for *combustible fuels*, 2003, are given in Table 7 of IEA (2005: I.43)[10], part of which is included as Table 6 below.

[9] Net production = Gross production – Own use by power plants

[10] Table 8 of IEA (2005) has heat production figures, but note that the figures are only for *heat sold to third parties* and do not include heat production in industry for *own-use*.

Table 6: Electricity production figures for OCED and non-OECD nations, by energy source (TWh)

	Coal				Oil	Gas	Solid	Indust.	Municip.	Biomass
	Hard	Brown	Peat	Gases			Biomass	Waste	Waste	Gases
OECD Total	3170.38	571.94	9.51	90.75	561.24	1728.14	93.28	15.95	42.13	18.10
Non-OECD Total	2622.65	187.56	0.89	22.56	590.49	1496.56	26.78	1.78	2.64	0.05
World	**5793.03**	**759.50**	**10.40**	**113.31**	**1151.73**	**3224.70**	**120.06**	**17.73**	**44.77**	**18.15**

For all types of fuels in the *OECD* countries, detailed production totals, in TWh, are available in Table 10 (IEA, 2005: I.54), which is reproduced as Table 7 below.

Table 7: Electricity production totals for OECD countries, by energy source (TWh)

	1973	1980	1990	2000	2002	2003	Average annual percent change 73-90	90-03
Nuclear	188.5	620.7	1724.8	2244.4	2276.0	2223.4	13.9	2.0
Hydro	925.6	1100.4	1213.0	1386.9	1335.1	1317.3	1.6	0.6
of which:								
Pumped Storage Production	*13.2*	*15.7*	*42.8*	*68.5*	*70.2*	*75.5*	*7.2*	*4.5*
Geothermal	6.6	11.1	28.7	33.0	32.9	34.3	9.0	1.4
Solar	-	-	0.7	0.7	0.9	1.1	-	3.7
Tide, Wave, Ocean	0.6	0.5	0.6	0.6	0.6	0.6	0.4	-0.3
Wind	-	0.0	3.8	28.5	48.3	58.3	-	23.3
Other (e.g. Fuel cells)	-	0.0	0.1	1.8	1.9	1.9	-	23.4
Combustible Fuels	3346.0	3927.1	4635.5	5961.6	6133.6	6301.4	1.9	2.4
Coal	*1693.5*	*2317.0*	*3059.8*	*3710.9*	*3714.1*	*3842.6*	*3.5*	*1.8*
Oil	*1125.2*	*978.7*	*692.7*	*579.0*	*555.9*	*561.2*	*-2.8*	*-1.6*
Gas	*520.2*	*617.7*	*764.6*	*1524.4*	*1702.8*	*1728.1*	*2.3*	*6.5*
Comb. Renew. & Waste	*7.2*	*13.7*	*118.4*	*147.4*	*160.8*	*160.5*	*18.0*	*2.9*
Gross Production	**4467.3**	**5659.8**	**7607.3**	**9657.5**	**9829.3**	**9938.3**	**3.2**	**2.1**
Own Use by Power Plant	219.2	293.9	405.3	488.0	452.3	458.7	3.7	1.0
Net Production(1)	**4248.1**	**5365.9**	**7201.9**	**9169.5**	**9377.1**	**9479.6**	**3.2**	**2.1**
Used for Heat Pumps	-	-	0.4	3.0	2.2	2.2	-	13.5
Used for Electric Boilers	-	-	0.8	3.8	3.1	2.0	-	7.2
Used for Pumped Storage	19.1	25.5	65.7	92.4	90.7	97.6	7.5	3.1
Imports	87.7	140.3	255.3	342.7	359.9	371.9	6.5	2.9
Exports	81.4	124.6	231.9	339.6	340.3	353.5	6.3	3.3
Electrical Energy Supplied(2)	**4235.2**	**5356.1**	**7158.4**	**9073.5**	**9292.7**	**9396.2**	**3.1**	**2.1**
Transmission & Dist'n Losses	349.1	437.7	580.8	613.8	679.4	669.8	3.0	1.1
Energy Sector Consumption(3)	128.7	179.1	211.3	232.0	245.5	253.4	3.0	1.4
Final Consumption(4)	**3757.5**	**4739.4**	**6366.3**	**8227.0**	**8367.0**	**8472.9**	**3.2**	**2.2**
Other commonly reported data series:								
Electricity Generated(5)	4454.0	5644.1	7564.5	9589.0	9759.1	9862.8	3.2	2.1
Electricity Requirements(6)	4473.6	5675.5	7630.7	9660.6	9848.9	9956.7	3.2	2.1
Electricity Consumed(7)	3886.2	4918.4	6577.6	8459.7	8613.3	8726.4	3.1	2.2

Source: IEA/OECD *Energy Statistics of OECD Countries.*

(1) Net Production = Gross Production - Own Use by Power Plants.

(2) Electrical Energy Supplied = Net Production - Used for Heat Pumps, Electric Boilers and Pumped Storage + Imports - Exports.

Note: This includes electricity generation from *main activity producer* power plants and *autoproducers.*

(3) Energy Sector Consumption = electricity consumed by transformation industries for heating, traction and lighting purposes; excludes Own Use by Power Plant, Used for Heat Pumps, Electric Boilers and Pumped Storage.

(4) Final Consumption = Electrical Energy Supplied - Transmission and Distribution Losses - Energy Sector Consumption.

(5) Electricity Generated = Gross Production - Amount of electricity produced in Pumped Storage Plants.

(6) Electricity Requirements = Gross Production – Imports - Exports.

(7) Electricity Consumed = Electrical Energy Supplied - Transmission and Distribution Losses.
= Final Consumption + Energy Sector Consumption.

1.2.3 Real-World Electricity Capital Stock

This section deals with the **available data** on global electricity-producing capital stock, and **produces figures** that are useful as inputs to the model and as values for cross-checking model behaviour. Its subsections provide data on capital construction times and capital lifetimes (1.2.3.1), and on basic costs for the various electricity production technologies currently available (1.2.3.2). Then, using these cost data, it calculates the global historical and currently installed electricity-production capital by production-technology (1.2.3.3).

Electricity is generated by electric plants, which are referred to as the *electricity-producing capital stock*. This capital stock has certain characteristics like lifetime and efficiency, energy requirements per unit electricity produced, and required time to complete construction. Some of these characteristics – life- and construction times – are documented (1.2.3.1).

Electricity capital stock is represented in terms of the energy sources it uses (coal, oil, natural gas, hydro, nuclear, and alternative)[11, 12]. Useful sources for the **electrical plant costs** (1.2.3.2) include Breeze (2005)[13] and Shaalan (2001)[14], and the World Energy Council (WEC, 2007) also contains some basic price information on a few energy sources. Given these prices, the next step is to translate those individual costs first into global electricity **production capacity** (in GW yr^{-1}), and then to use the cost figures to determine actual global investments (1.2.3.3). A significant problem in modelling energy and electricity capital is that the actual value of economic capital, particularly in 1960, is not easily found, and energy capital stocks are even more difficult to find – for electricity production, the IEA (2005) only has figures from 1974 onward, for example, which are available only for IEA and OECD countries and not the entire world, while the more comprehensive EIA (2006) figures are available only from 1980 onwards. Furthermore, in many cases, values are not provided for individual thermal electricity-production technologies, but are instead lumped into one generic *thermal* source, so assumptions are required in disaggregating these figures.

1.2.3.1 Electricity Capital Construction Delays and Capital Lifetimes

Significant delays exist between the initiation of planning and construction, and the subsequent connection of new electricity plants to the grid, as shown in Table 8.[15]

[11] Electrical energy is disaggregated by energy source because each produces very different amounts of greenhouse gases, and electric energy production is highly regulated and controllable by government policy.

[12] Of course, the heat-generating (non-electric) capital stock uses energy sources in different amounts, but is not disaggregated in the same way – it uses coal, oil, and natural gas, and possibly biomass. See section **Error! Reference source not found.**, below.

[13] Figures from Breeze (2005: 40) assume that NO_x, sulfur dioxide, and particulates are being controlled to meet US regulation levels. Capital costs can be reduced without these requirements.

[14] It is not clear whether the figures in Shaalan (2001) are only for the U.S. or whether they apply more broadly. Furthermore, figures in Shaalan (2001) are provided only for a small group of plant types.

[15] These differences in construction times have not yet been included to any real degree in the model. Assumed construction times are currently set to 8, 8, 8, 4, 10, and 10, for coal, oil, natural gas, alternatives, nuclear, and hydro, respectively.

Table 8: Time required to construct and license power plants in the U.S.[1]

Plant Type	Years
Nuclear	8-14
Fossil Fuel-fired Steam	6-10
Combined-cycle Units	4-8
Combustion Turbine	3-5

[1] Table 8.12 in Shaalan (2001)

Once constructed, electricity production capital has a certain lifetime. Fiddaman (1997) sets the lifetimes of energy producers by fuel type to 20 years (coal), 20 (oil/gas), 40 (nuclear/hydro), 30 (alternatives), while the SGM and EPPA models use 15 and 25 years, respectively, for all electricity producing plants except for hydro, for which SGM uses 70 years.[16]

1.2.3.2 Costs of Electricity-Producing Capital

In terms of capital costs (neglecting annual fuel and variable O&M costs), several different power plant alternatives have the following price characteristics:

- **Coal-fired**[17] plants:
    - Steam cycle: \$450M for 600 MW plant, or annual fixed capital and O&M costs of \$126.25 $kWyr^{-1}$ (Shaalan, 2001);
    - Conventional plant (pulverized coal) with emissions control: 1079-1400 \$ kW^{-1} (capital cost, 16% financing costs omitted?), and \$22.5 kW^{-1} for fixed O&M costs (Breeze, 2005). The WEC (2007: 4) lists costs of \$750 kW^{-1}, and for advanced conventional plants (supercritical plants), the price is about \$1000 kW^{-1};
    - Atmospheric fluidized bed: 1300-1800 \$ kW^{-1} capital cost, and \$22.5 kW^{-1} for fixed O&M costs (Breeze, 2005);
    - Pressurized fluidized bed: 1200-1500 \$/kW capital cost, and \$22.5 kW^{-1} for fixed O&M costs (Breeze, 2005);
    - IGCC: (1200)-1500-1800 \$ kW^{-1} capital cost, and \$24.2 kW^{-1} for fixed O&M costs (Breeze, 2005). According to the WEC (2007: 4), prices are about \$1500 kW^{-1};
- **Oil-fired** plants:
    - Steam cycle: \$360M for 600 MW plant, or annual fixed capital and O&M costs of \$101.50 $kWyr^{-1}$ (Shaalan, 2001);
    - Combined cycle[18]: \$130.5M for 300 MW plant, or annual fixed capital and O&M costs of \$82.55 $kWyr^{-1}$ (Shaalan, 2001);
    - Combustion turbine: \$8.5M for 50 MW plant, or annual fixed capital and O&M costs of \$37.50 $kWyr^{-1}$ (Shaalan, 2001);
    - Breeze (2005) does not discuss oil-fired power;

[16] Again, the treatment of capital lifetimes in the model is currently quite simple. Capital lifetimes are set to 20, 20, 20, 20, 20, and 50, where the longest lifetime applies to hydroelectric capital.

[17] Breeze (2005: 19) writes that modern coal-fired plants with emissions-control systems are more expensive than the older type of plant common before the mid-1980s. Even so, coal remains the cheapest way of generating power in many parts of the globe.

[18] A combined cycle plant uses both steam and gas turbines and can be licensed and built relatively quickly. Combined cycle plants are a relatively recent development.

- **Natural gas-fired**[19] plants:
    - Steam cycle: \$348M for 600 MW plant, or annual fixed capital and O&M costs of \$126.25 $kWyr^{-1}$ (Shaalan, 2001);
    - Combustion turbine: \$8M for 50 MW plant, or annual fixed capital and O&M costs of \$35.25 $kWyr^{-1}$ (Shaalan, 2001);
    - Combined cycle (turbine + steam):
        - \$500-550 kW^{-1} with fixed O&M costs of 15mills kWh^{-1}; 1994 capital cost was \$800 kW^{-1} (Breeze, 2005);
        - \$126M for 300 MW plant, or annual fixed capital and O&M costs of \$79.60 $kWyr^{-1}$ (Shaalan, 2001);
    - Simple cycle gas turbine: \$389 kW^{-1} (Breeze, 2005);
- **Nuclear**[20] plants: Most of the costs are up-front, and can be high, but actual electricity production is quite cheap (Breeze, 2005)
    - \$900M for 900 MW plant, or annual fixed capital and O&M costs of \$165.07 $kWyr^{-1}$ (Shaalan, 2001);
    - Capital costs have risen considerably since the 1970s so that, while unit costs in the early-70s were \$150-300 kW^{-1}, they had risen to \$1500-3000 kW^{-1} by the late 1980s (Breeze, 2005);
- **Hydroelectric**[21] plants: Most of the costs are up-front, and can be high
    - Costs can range from \$700 kW^{-1} to \$3500 kW^{-1}. Medium and large-scale projects typically cost roughly \$740 kW^{-1}, but smaller projects can be more costly (roughly \$800 kW^{-1} to \$1500 kW^{-1}, but can run to \$6000 kW^{-1}), as are projects on remote sites (Breeze, 2005). Electricity costs range from 4-8 cents kWh^{-1} while the loan is repaid, and then typically fall to 1-4 cents kWh^{-1} (Breeze, 2005)
- **Diesel** engine: \$3M for 8 MW plant, or annual fixed capital and O&M costs of \$78.00/kWyr (Shaalan, 2001);
- **Wind**[22] power: Installation costs fell rapidly during the 1980s and 1990s, with a cost-decline of 60-70% between 1985 and 1994. Prices are still falling, but the rate has slowed. Current prices are now €700-1000/kW for onshore developments and roughly €1500 kW^{-1} for offshore installations, although their price could drop to €1000 kW^{-1} by 2010 (Breeze, 2005: 167)
- **Solar**[23] power: Capital costs and electricity costs are relatively high, but have fallen significantly in the last thirty-or-so years.

[19] Breeze (2005: 43) writes that gas turbines have only become popular since the 1990s, although there was some use in the 1970s and 1980s. Gas turbine plants are cheap, but their fuel is expensive.

[20] Breeze (2005) writes that nuclear plant decommissioning, because of radioactivity, is also costly and should be included in the capital costs. Decommissioning can cost roughly 9-15% of the initial capital expenditure.

[21] Breeze (2005: 105) provides technically-exploitable hydropower resources – a global total of 14 400 TWh yr^{-1}; global capacity is currently 692 400 MW, meaning that two-thirds of the global capacity remains unexploited

[22] Breeze (2005: 157) writes that the original wind turbines of the 1970s had a per-turbine energy production of only 30-60 kW, but that that capacity had increased to 300-500 kW per turbine by the 1980s. By 1998, most new wind farms had turbines with individual capacities of 600-750 kW. In the current decade, per-turbine capacity has reached 2-5 MW, and by the end of the decade, the capacity may increase to 6-10 MW for off-shore sites.

[23] Breeze (2005: 185) writes that the total installed capacity of solar generation is tiny: roughly 800 MW in 1995. The total capacity may have reached 3400 MW by 2004.

- Solar thermal plants: Solar troughs have a capital cost of about \$2900 kW^{-1}, solar towers of \$2400-2900 kW^{-1}, and solar dishes of \$2900 kW^{-1}. By 2010, the US DOE predicts that solar towers may be able to generate electricity at a levelized cost of \$0.05 kWh^{-1} (Breeze, 2005);
- Photovoltaic plants: Photovoltaic cells are quite expensive, but have fallen significantly in price from \$4250 kW^{-1} in 1993 to \$3000 kW^{-1} in 2003. Installed AC systems then cost \$12000 kW^{-1} in 1993 and \$6000-8000 kW^{-1} in 2003 (Breeze, 2005).

Where possible, **fixed and variable operation and maintenance costs** are given for the generating technologies listed above. Such figures, however, are difficult to find, and so the relative price-based ranking of electricity-production technologies given in Table 8.3 of Shaalan (2001: 8.4) may prove useful.

1.2.3.3 Calculated Electricity Production Capital

Using the data listed above for global electricity-production capacities and capital costs of electrical plants, I have created an **MS Excel database**. This Excel file is called "Energy-Capital Calculations" and its important calculated outputs are provided here. The file has five worksheets/pages:

- *Capacity*, which calculates the global electrical production capacity from 1974 (rough values), and from 1980-2003 as more certain values;
- *Capital Costs*, which assembles estimates on global capital costs for electricity-production plant installation – the values given are primarily *current* installation costs, but historical costs are provided where possible;
- *Installed Capital*, which uses the result of the previous two pages to determine the value of total installed electricity-production capital;
- *Investment*, which offers rough calculations on the required annual investment in electricity-production to meet the figures in the *installed capital* spreadsheet; and,
- *Regional Distribution*, which provides the global production capacity by economic bloc and geographic region.

In most cases, the values provided by various sources are used directly; however, the data have certain limitations, so that guesses were sometimes necessary – these guessed values are highlighted with *italics*.

In terms of **electricity-production capacity**, the global values in Table 9 were calculated from EIA (2006) and IEA (2005) data:

Table 9: Global installed electricity-generating capacity (GW)

Fuel Type	1974	1980	1990	2000	2003
Thermal	*1163.1*	1347.8	1737.6	2195.5	2485.8
Assigned Coal (%)	*52%*	*53%*	*56%*	*53%*	*47%*
Coal	*610.4*	714.6	976.3	1155.8	1169.5
Assigned Oil (%)	*30%*	*25%*	*20%*	*14%*	*11%*
Oil	*352.7*	339.2	350.9	300.9	272.3
Assigned Natural Gas (%)	*17%*	*22%*	*24%*	*34%*	*42%*
Natural Gas	*200.0*	294.0	410.4	738.9	1044.0
Total	*100%*	*100%*	*100%*	*100%*	*100%*
Hydro	*305.7*	457.2	575.4	683.3	720.3

Nuclear	*52.92*	135.5	323.1	358.3	368.5
Alt E	*2.1*	5	22.1	42.3	64.3
Total	*1523.8*	1945.5	2658.2	3279.4	3638.9

The EIA (2006) provides electrical production values for thermal plants, hydro, nuclear, and alternative energy plants, but not for specific fuel types – coal, oil, and natural gas – during the time period from 1980-2005. The IEA (2005) gives more detailed figures from 1974-2003 for both OECD and IEA countries, but does not give global values. Therefore, in assembling the values in Table 9, above, the fraction of total electricity produced in OECD nations, shown in Table 10, was used to weight the coal, oil, and natural gas fractions of the total thermal production, as well as a set of guesses (see Table 11, below) about these thermal sources in non-OECD nations.[24] Note that Table 11 gives OECD percentages for 2003, while guesses are for 2005.

Table 10: Fraction of global capacity in OECD nations, from EIA (2006) and IEA (2005) data (in GW and %)

Year	1974	1980	1985	1990	2000	2003
Global Total (EIA)	*1502.2*	1945.6	2315.4	2658.3	3279.3	3638.9
OECD Total (IEA)	993.32	*1286.5*	1530.9	1700	2057.3	2351.6
Percentage	*66.1%*	66.1%	66.1%	64.0%	62.7%	64.6%
Global **Thermal** Total (EIA)	*1163.7*	1347.8	1542.5	1737.6	2195.5	2485.8
OECD Thermal Total (IEA)	760.72	*881.05*	981.32	1058.36	1312.76	1574.13
Percentage	*65.4%*	65.4%	63.6%	60.9%	59.8%	63.3%
Global **Hydro** Total (EIA)	*305.7*	457.2	527.2	575.4	683.3	720.3
OECD Hydro Total (IEA)	178.8	*267.4*	341.3	369.18	420.25	421.32
Percentage	*58.5%*	58.5%	64.7%	64.2%	61.5%	58.5%
Global **Nuclear** Total (EIA)	*52.92*	135.5	236.8	323.1	358.3	368.5
OECD Nuclear Total (IEA)	52.92	*135.9*	205.05	265.03	302.09	313.14
Percentage	*100.0%*	100.3%	86.6%	82.0%	84.3%	85.0%
Global **Alternatives** (EIA)	*2.1*	5	8.9	22.1	42.3	64.3
OECD Alternatives (IEA)	0.88	*2.1*	3.2	7.5	22.2	43.0
Percentage	*42.9%*	42.9%	36.0%	33.8%	52.4%	66.9%

Table 11: Thermal electricity-production by fuel type: OECD vs. non-OECD nations (in %)

	1974	1980	1990	2000	2005
OECD Coal	51.0%	53.0%	56.0%	50.0%	42.0%
Non-OECD Coal	*55.0%*	*53.0%*	*56.0%*	*56.0%*	*56.0%*
OECD Oil	30.0%	25.0%	19.0%	14.0%	11.0%
Non-OECD Oil	*31.0%*	*25.0%*	*22.0%*	*14.0%*	*11.0%*
OECD Natural Gas	19.0%	22.0%	25.0%	36.0%	47.0%
Non-OECD Natural Gas	*14.0%*	*22.0%*	*22.0%*	*30.0%*	*33.0%*

[24] These guesses can be altered easily in the spreadsheet to see the effect on global installed capacity (GW) and capital costs ($). The non-OECD values in Table 11 may actually be slightly low, since China and India use primarily thermal (especially coal) generation in electricity generation: thermal power generation accounts for 74% of China's installed capacity (at 290 GW) and 83% of the electricity generation in 2003, while hydro supplied the majority of the remaining generation (China Electric Power Information Center, 2008); in India, electricity generation in 2008-9 will reach 744 BU [unknown unit], of which 631 BU will be thermal generation (Government of India, 2008).

In all, the distribution of electricity production capacity by region, economic group, or country in 2005 was arranged as shown in Figure 5; Figure 6 shows the distribution in OECD and Non-OECD nations by fuel source. Both figures are based on Table 6.4 of EIA (2006).

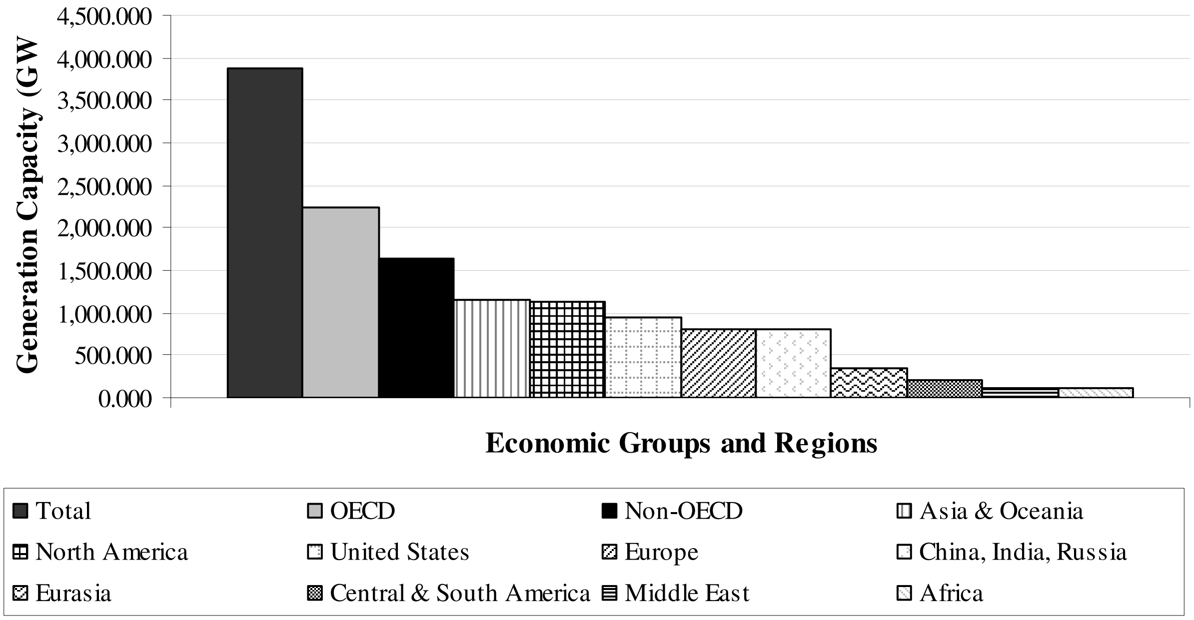


Figure 5: Electricity-production capacity by group and region (GW)

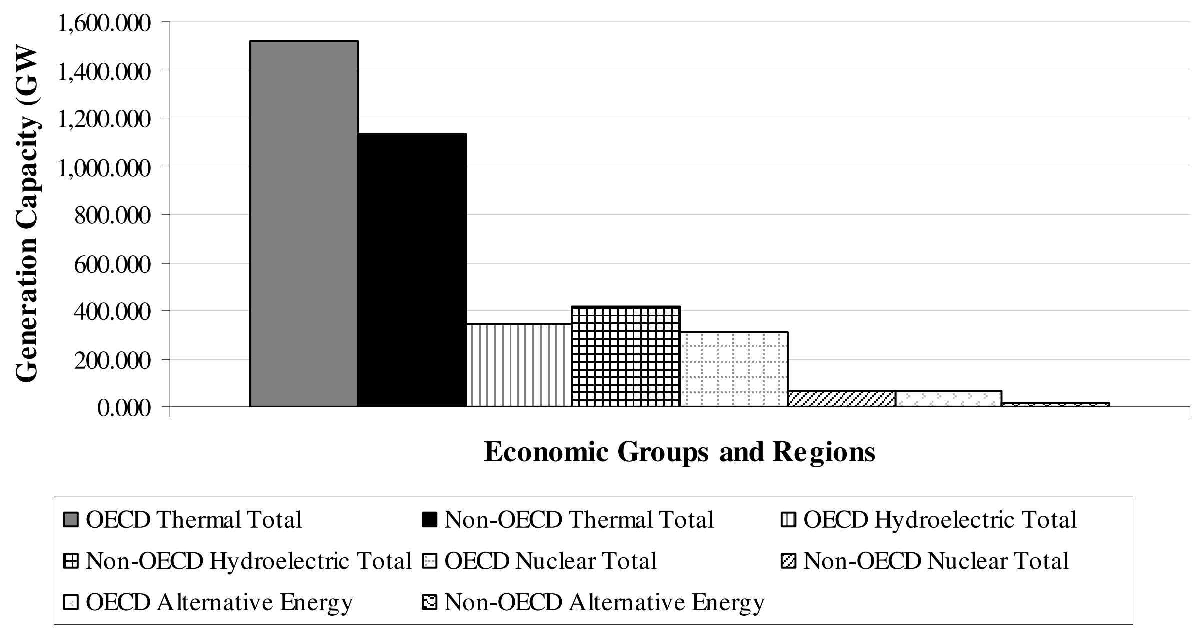


Figure 6: Electricity-production capacity by fuel type (GW)

Note that a significant discrepancy exists between the EIA (2006) and IEA (2005) hydroelectric figures, which has a significant effect on the hydroelectricity columns in the figure above – the reason seems to be that the IEA includes pumped storage for hydro, while the EIA does not.[25]

For **Capital Costs**, the capital installation figures provided above were weighted by fuel source according to guesses about the prevalence of various production technologies. The weightings are listed in Table 12, and can be changed easily in the Excel spreadsheet to give a different value for the installed capital.

Table 12: Assumed prevalence of specific electricity production technologies, by fuel type

Fuel Type	Current Prevalence (%)	Hist. Prevalence (%)
Coal-fired		
Steam cycle, Pulverized coal	58%	
Pulverized coal + emissions control	20%	
Advanced conventional	20%	
Pressurized fluidized bed + em. cont.	1%	
Int. Gasification Combined Cycle (IGCC)	1%	
Oil-fired		
Steam cycle	88%	
Combined cycle	5%	
Combustion turbine	5%	
Diesel	2%	
Natural Gas		(to 1990s)
Steam cycle	60%	0%
Combined cycle	40%	100%[1]
Nuclear		
	N/A	
Hydroelectric		
Medium to large projects	70%	
Smaller projects	30%	
Wind and Solar		
Wind: current price, onshore	75%	Earliest Alt. E. was
Wind: current price, offshore	24%	actually primarily geothermal
Solar tower	1%	

[1] All natural gas plants were more expensive at this time – in the price range of combined-cycle plants – and at least 70% were of this type until relatively recently.

In conjunction with these weightings, the technology-specific capital costs were used to determine weighted-average capital installation costs for each of the fuel types. For example, in the case of the relatively-simple natural gas-fired plant, the steam cycle technology has an average capital cost of \$580 kW^{-1}, while the combined cycle plant has an average cost of \$525 kW^{-1} (after 1994), so that the weighted cost is $0.6*580+0.4*525 = \$558\ kW^{-1}$. Using calculations of this sort yields the capital costs in Table 13:

[25] Pumped storage of 82 GW in IEA figures may account for the difference in hydroelectric capacity: 346 GW (EIA) and 421 GW (IEA).

Table 13: Average cost of electricity-production capital installation (in \$ kW^{-1})

		Cost	
Fuel Source	Current	Historical	Year
Thermal	*726.3*	*815.9*	To 1990s
Coal-fired	916.4		
Oil-fired	554.9		
Natural Gas-fired	558	800	To 1990s
Nuclear	2250	225	In early 1970s
Hydro	863		
Alternative	1423	2276.8	To 1994 (current value + 60%)

Finally, with the capital costs determined, the value of the **Installed Capital** can be determined by multiplying the installed capacity by its average cost, and adjusting for unit scales. The calculation takes this form: *[Capacity] * [Capital Cost] * [Unit adjustment] = [Installed Capacity]*, or by units, $GW * (\$/kW) * 10^6\ kW/GW = \$$. The values of global installed electricity-capital are given in Table 14, and, for the sake of clarity, in Figure 7 too.

Table 14: Global installed electricity-generating capital (in 10^9 \$)

Fuel Type	1974	1980	1990	2000	2003
Thermal	915.1	1078.3	1417.7	1638.3	1805.3
Coal	559.4	654.9	894.6	1059.1	1071.7
Oil	195.7	188.2	194.7	166.9	151.1
Natural Gas	160.0	235.2	328.3	412.3	582.5
Nuclear	11.9	167.7	727.0	806.2	829.1
Hydro	263.8	394.6	496.6	589.7	621.6
Alternative	4.7	11.4	50.3	60.2	91.5
Total Capital	1195.4	1651.9	2691.5	3094.4	3347.6

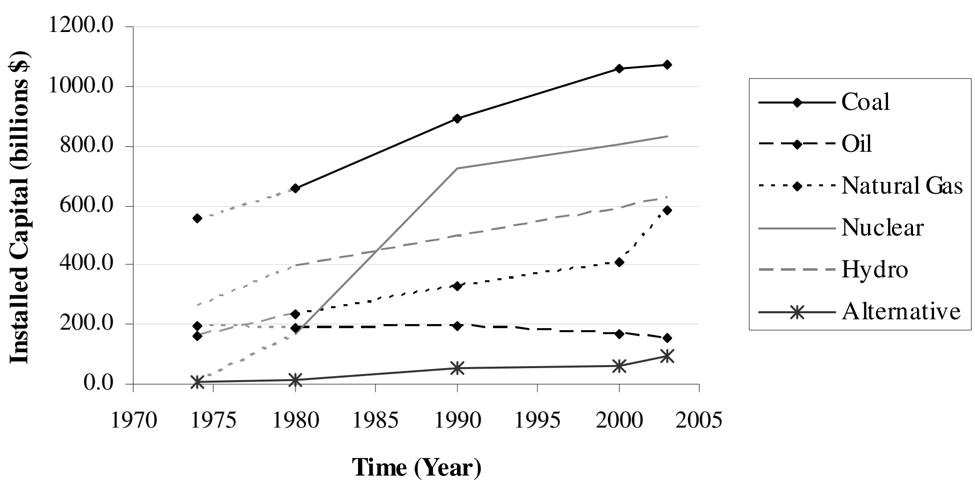


Figure 7: Global installed electricity-generating capital (in 10^9 \$)

To **check the plausibility** of these figures, they are compared in Table 15 with the total global installed capital, as simulated by my current (DICE-based) version of the model, showing that electricity-generating capital is a very small proportion of the total capital.

Table 15: Global installed capital (based on DICE) versus electricity-generating capital (in 10^9 \$)

Year	1974	1980	1990	2000	2003
Simulated Capital	22800	31730	46140	65440	72840
Electricity Capital	1195.4	1651.9	2691.5	3094.4	3347.6
As percentage	5.2%	5.2%	5.8%	4.7%	4.6%

Next, a comparison of electricity investment versus global GDP in Table 16 reveals the same effect – that electricity investment is likewise a small component of the annual GDP. Note that the annual investment is calculated on the *Energy-Capital Calculations* spreadsheet, and that its values both include depreciation of the capital stock and are approximate only. The calculated investment figures are an annual average over each time period, from 1974-1980, 1980-1990, and so on; furthermore, the *1970* figure given is actually the 1974-1980 figure for investment.

Table 16: Global Gross Domestic Product versus investment in electricity-generating capital (in 10^9 \$ yr^{-1})

Year	*1970*	1980	1990	2000
Simulated GDP	10070	15260	20450	26390
Investment	130.3	203.8	90.7	160.1
As percentage	1.3%	1.3%	0.4%	0.6%
WDI Online (2007)	12200	17620	23960	31780
Investment	130.3	203.8	90.7	160.1
As percentage	1.1%	1.2%	0.4%	0.5%

2. Resource Extraction

Non-renewable energy resources supply the larger part of global energy demands: about 78% of the world's energy use takes the form of *heat-energy*; furthermore, of the remaining 22%, which consists of *electrical-energy*, a considerable part requires fossil fuels as well (IEA, 2007d: 25). Non-renewable energy resources are mined (coal and uranium[26]), pumped (oil and natural gas), or collected and burned (biomass[27]). The first part of this section describes energy resource modelling in a series of energy-economy models (2.1), while the second part describes energy reserves, extraction capital and capacity, and their change over time in a Vensim model (2.2).

In reality, there are limits to the rate at which new capacity for resource extraction can be added. In the current version of the model, limitations to capacity expansion are economic: if investment funds – from extraction-activity profits – are unavailable, no expansion occurs (2.2). However, other considerations also exist, and should possibly be included in future model versions: 1) new sites may not be as productive as older sites, because rising demand drives the extraction or utilization of more marginal resources, and 2) saturation effects also arise, because the establishment of new sites or higher extraction rates at existing sites can both introduce bottlenecks into production (Fiddaman, 1997).

2.1 Overview of Energy Resource Modelling

The sections below describe energy resource modelling in several well-known energy-economy or IA models: FREE (2.1.1), COAL2 (2.1.2), TIME(R) (2.1.3), DICE (2.1.4), and SGM (2.1.5).

2.1.1 The FREE Model

In general terms, "the energy sector [in FREE] produces energy to meet orders from the goods producing sector. Energy producing capital is fixed in the short run, and the energy sector varies production by adjusting the rate of variable (goods) inputs to set capacity utilization to the required level. In the long run, the energy sector adjusts its capacity by varying the capital stock in response to production pressure and profit incentives" (Fiddaman, 1997: 96). Coal and other non-renewable fuels are subject to increasing production costs with fuel reserve depletion, and have an upper rate for depletion of the remaining fuel resources.

Energy resource production in FREE is determined through a CES Production function,

[26] Uranium mining is not currently modelled explicitly, because of unusual behaviour in nuclear markets (see Chapter 6 of World Energy Council, 2007). For example, uranium is now used faster than it is mined because over-mining in earlier decades led to the establishment of sizeable stockpiles, which reduced prices and thus discouraged further mining. As awareness of the imbalance has grown, and stockpiles shrunk, markets have responded as expected, with prices rising and new mines opening; however, earlier behaviour would be hard to replicate. Furthermore, nuclear plant establishment is prescribed in the model anyway.

[27] Biomass remains an important fuel source in developing countries, although its use is generally expected to decrease with development. It is most commonly used in the residential sector (de Vries et al., 2001: 71)

$$EP_i = EP_{i,0} \cdot \left(\alpha_{i,r} \left(\frac{R_i}{R_{i,0}} \right)^{\rho_{i,r}} + (1 - \alpha_{i,r}) EII_i^{\rho_{i,r}} \right)^{\left(\frac{1}{\rho_{i,r}}\right)}$$

where EP_i and $EP_{i,0}$ are the current and initial energy productions, R_i and $R_{i,0}$ are the current and initial resources remaining, EII_i is the effective input intensity, $\alpha_{i,r}$ are the resource shares, and $\rho_{i,r}$ are the resource substitution coefficients. The coefficient $\alpha_{i,r}$ represents the upper limit of energy production, which is the minimum time to extract all the remaining resource. The *effective input intensity*, EII_i, has the form of a Cobb-Douglas production function, and represents the relative effort devoted to resource extraction. It depends on the level of technology, capital, and variable (goods) inputs to production, such that,

$$EII_i = TE_i \cdot \left(\frac{KE_i}{KE_{i,0}} \right)^{\beta_{i,kv}} \left(\frac{V_i}{V_{i,0}} \right)^{(1-\beta_{i,kv})}$$

where TE_i is the energy technology, KE_i and $KE_{i,0}$ are the current and initial energy-capital, V_i and $V_{i,0}$ are the current and initial variable (goods) inputs, and $\beta_{i,kv}$ is the capital share.

While the approach and equations are fairly clear here, note that the variable inputs and energy capital – especially in terms of the energy capital order rate, EKO_i – are complicated and are hard to understand in FREE. See Appendix B, on page 159.

2.1.2 The COAL2 Model

COAL2 (Naill, 1977) is a *system dynamics* energy-economy model with three energy supply sectors – coal, oil&gas, and electricity – and one simple demand sector. The model focuses explicitly on the US and simulates a variety of "transition" policies[28] proposed to move the US economy from reliance on oil and gas imports.

From Naill (1977: 158), the following basic assumptions underlie resource supply in COAL2:

1. Domestic production of energy is determined by the output capacity of production facilities, and the utilization of capacity.
2. Production capacity is dependent on the following factors:
   conventional oil and gas — capital, resources
   synthetic oil and gas — capital, R&D, coal availability
   electricity — capital, environmental regulations, fuel availability
   coal — capital, labour, resources, environmental and safety standards

[28] Since the US is running out of domestic oil and gas sources, but has plentiful coal reserves (Naill, 1977), COAL2 investigates policies designed for a transition from imported oil and gas to domestic coal resources. Policies considered include those designed to accelerate nuclear power plant construction, increase reliance on coal reserves, impose oil and gas import quotas, deregulate oil prices, establish rate reform for electric utilities, accelerate synthetic fuels R&D, and/or consume less energy, and so on.

3. The ability of the oil and gas, coal, and electric utility industries to generate new capital investment from internal (retained earnings) and external (debt, equity) sources is limited. Price regulation (in the oil and gas and electric utility industries) tends to reduce investments below the maximum limit.
4. There is a limited stock of recoverable oil, gas, and coal resources in the United States. As resources are depleted, the productivity of the capital stock decreases (the capital/output ratio increases).
5. Unavoidable delays limit the responsiveness of energy supply: for example, 3-to 10-year construction delays, R&D delays (synthetic fuels, stack gas scrubbers), underground coal labour hiring delays, and response delays in the energy financing subsectors.
6. As oil and gas production capacity falls behind demand, the shortfall is made up with oil imports.

Finally, note that the equations for the COAL2 model are written in the DYNAMO language, and are provided in an appendix of Naill (1977). However, a general description of some COAL2 model components may prove useful to the modelling work here.

2.1.2.1 Causal Structure of COAL2

The causal structure of COAL2 is shown in Figure 8 below, with the demand sector at the top of the figure, and the three supply sectors below it. Each of the supply sectors includes a representation of the physical resource and its associated discovery and depletion processes, the current domestic production/extraction capacity, and the financing decisions for allocating available internal (and external) funds to new production capital of different types.

In terms of the fuels and fuel-conversion processes, oil and gas are modelled as a single, composite resource, because they are both increasingly *imported* [to the US] resources; furthermore, oil and gas can be produced domestically (after additional R&D efforts) through the conversion of coal reserves into synthetic fuels. Electricity is modelled as an energy conversion process and includes fossil fuel, nuclear, and hydroelectric sources (but not alternative energy sources). The sector includes both financing and fuel-mix decisions, which are influenced by capital costs, fuel costs, and environmental regulations. Finally, coal modelling is the real focus of the model. Coal production and investment decisions revolve around the resource location – either at the surface or underground[29] – and the associated relative prices.

[29] In COAL2, surface and underground mining are separated because “the resource, capital, labour, and environmental characteristics of each production process are significantly different” (Naill, 1977: 13): while underground mining requires significantly more labour than surface mining does and is subject to different environmental and labour regulations in the US, surface mining is environmentally damaging but requires negligible labour (at least in COAL2). Generally, surface mining is less expensive than underground mining, but underground resources are much more plentiful.

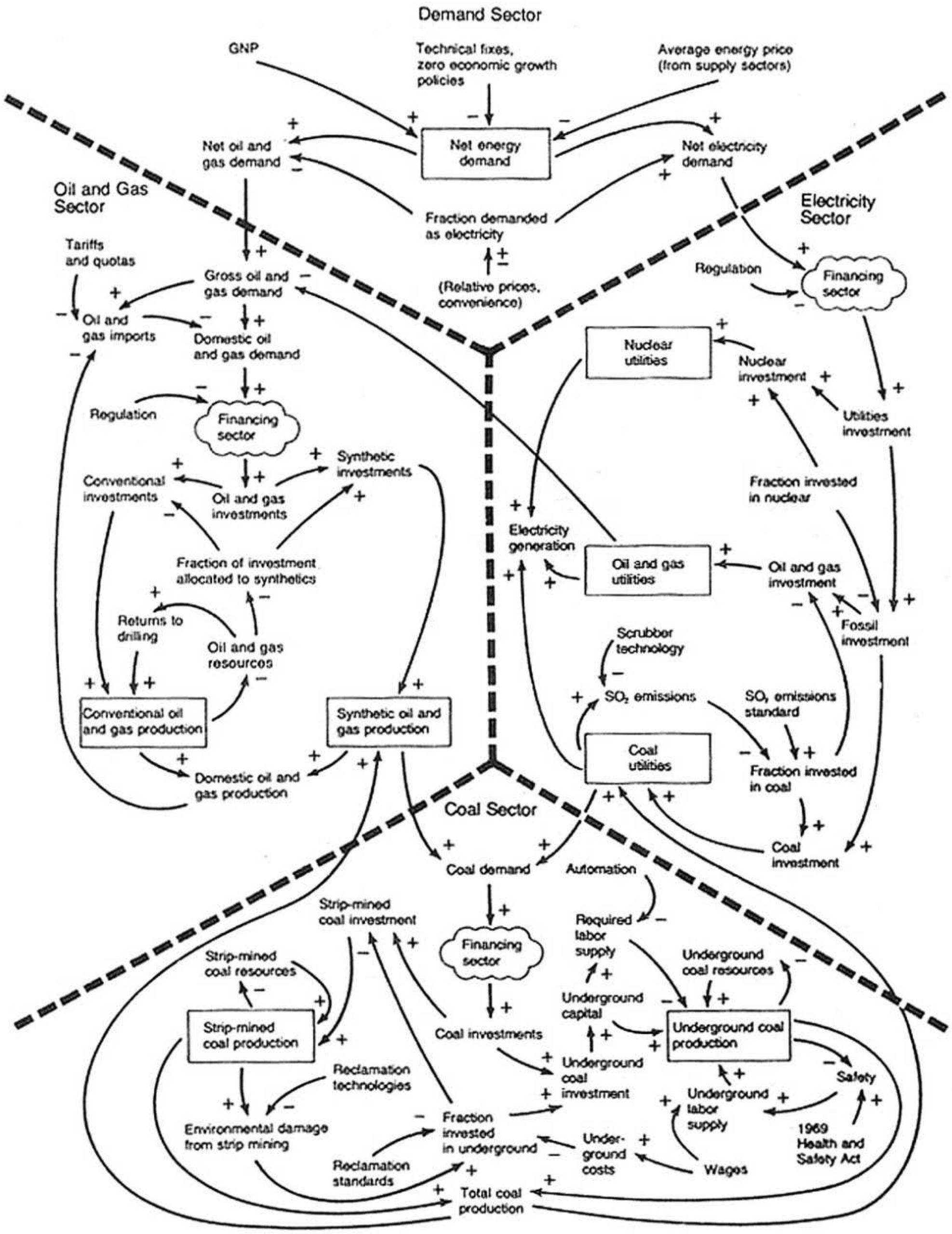


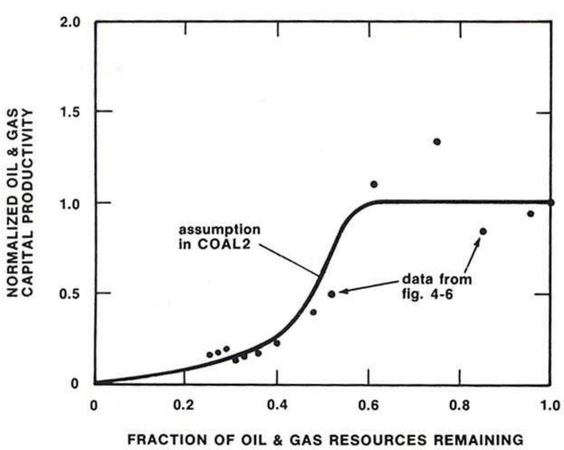
Figure 8: The feedback structure of the COAL2 model

2.1.2.2 Depletion Effects in COAL2

In each resource sector, production both depletes the remaining resource stock (not surprisingly) and reduces the capital productivity (more cleverly). Basically, Naill (1977: 57) models the observation that a decrease in capital productivity (equivalent to a rise in capital costs) occurs as oil and gas production shifts to smaller, less productive pools, or less accessible drilling locations:

Resource depletion constantly increases the marginal cost of production, making it increasingly difficult for producers to meet demand, even if demand remains constant. Producers attempt to offset the effects of resource depletion by investing greater amounts of capital in drill rigs and associated equipment, given the proper investment incentives.

This depletion-productivity connection is depicted in Figure 9, where the fraction of the resource remaining is shown on the horizontal axis and the productivity effect is on the vertical. In the case of coal, both seam thickness and depth clearly play important roles in determining the difficulty and cost associated with coal extraction.



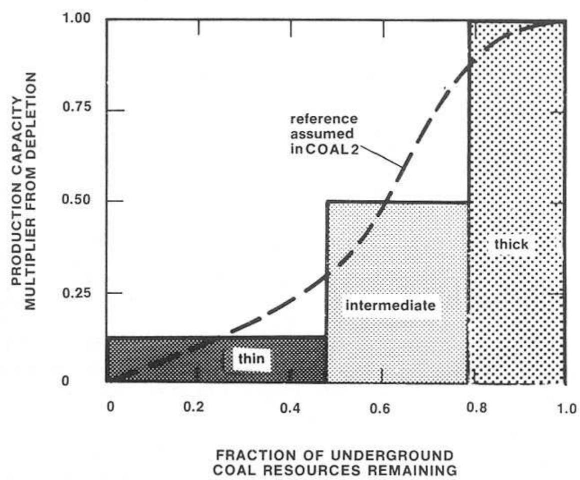


Figure 9: Relationship between resource depletion and productivity in the COAL2 model (Naill, 1977)[30]

Finally, a complicating factor is the *ultimate recoverable resource*. According to Naill (1977), existing mining methods normally permit only 50% of underground coal resources and 90% of surface resources to be recovered – in the case of underground mining, about half of the coal is left in underground mines to support the roof.

2.1.2.3 Resource Production in COAL2

Resource production capacities determine maximum production. Naill (1977) does not provide the production function details for oil & gas, but he does provide information on coal production.

In COAL2, the coal sector employs two production functions: one for surface coal and one for underground coal. These two functions determine the *production capacity* of coal mines, which establishes an upper limit to production. However, producers generally operate their mines well below this maximum level and adjust capacity utilization (days worked per year) to meet demand. In a case of rapidly increasing demand, additional capacity may be required.

Both functions take the form of modified Cobb-Douglas production functions,

[30] The left-hand figure is number 4-11 in Naill (1977), “Derivation of oil and gas capital productivity relationship”, while the right-hand figure is number 6-16, “Relation of underground coal depletion to production”

$X = g \cdot K^a L^b R^c$

where X is the coal output, K is capital[31], L is labour[32], and R is the resource stock[33]. COAL2 does not assign constant values for g (a productivity measure) or for a, b, and c (the input elasticities), but instead uses variable, nonlinear elasticities – the function is a *modified* Cobb-Douglas, after all. The structure of the coal sector therefore focuses on basic mechanisms that control the flows of capital, labour, and resources in the coal industry.

2.1.2.4 Investment in COAL2

Investment ultimately determines the resource production capacity, and its availability depends on,

1. The revenue flow that provides the main *source* of capital funds; and,
2. The average return on investment, which provides the *incentive* to commit available funds to new projects.

Both *internal* and *external* funding sources are included in COAL2, where internal sources are calculated from revenues and include retained earnings, depreciation, and amortization, while external sources come from outside the oil and gas industry. Naill (1977) states that internal funding has historically remained fairly stable, at about *30% of total revenues*; furthermore, it is likely that an equal amount could come from external sources if the industry rate of return were high. Thus, a *maximum of roughly 60% of total revenues* could be invested yearly, given a high incentive to invest. This incentive for investment then comes from the average return on investment – a generally accepted measure of the health of an industry – which then controls both the commitment of internal funds and the ability to attract external funds.

To model the ROI effect in COAL2, a regression was conducted on historical petroleum industry data, which indicated a strong relationship between actual investment and the average return on investment of the industry, as shown in Figure 10. Unfortunately, Naill (1977) does not provide the equations for calculating revenues, changes in fuel prices, and the *return on investment* in symbolic form; instead, to determine the formulations used, it would be necessary to consult the code appendix, which is not straightforward because of the DYNAMO syntax. Furthermore, he does not state whether the same ROI-reinvestment formulation is used for the coal sector.

[31] The total capitalization of the coal mining industry grew substantially from about \$3.9 x 10^9 (1970 dollars) in 1950 to \$5.7 x 10^9 (1970 dollars) in 1970 – most of the capital expansion went towards replacing men with machines, while production has remained relatively constant (Naill, 1977: 123).

[32] Labour is included only in underground mining. Since labour availability is not expected to constrain surface production even under an accelerated growth scenario, it is omitted from the surface mining equation (b = 0).

[33] Most studies leave resources out of their production functions, but COAL2 includes the effects of resource depletion on both surface and underground coal production.

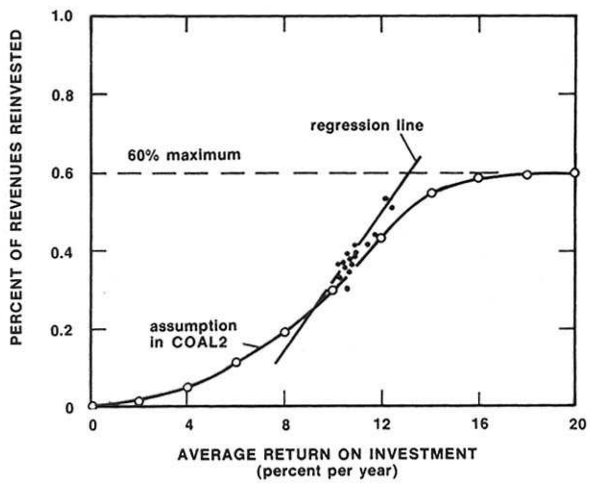


Figure 10: Oil and gas investment as a function of return on investment in Naill (1977, Figure 4-16)

Combining the revenue flow and average rate of investment with other important key variables yields the causal loop representation of the *domestic* oil and gas sector's financial structure shown on the left side of Figure 11 below. In contrast, the right hand side of the figure shows the financial structure in the coal sector.

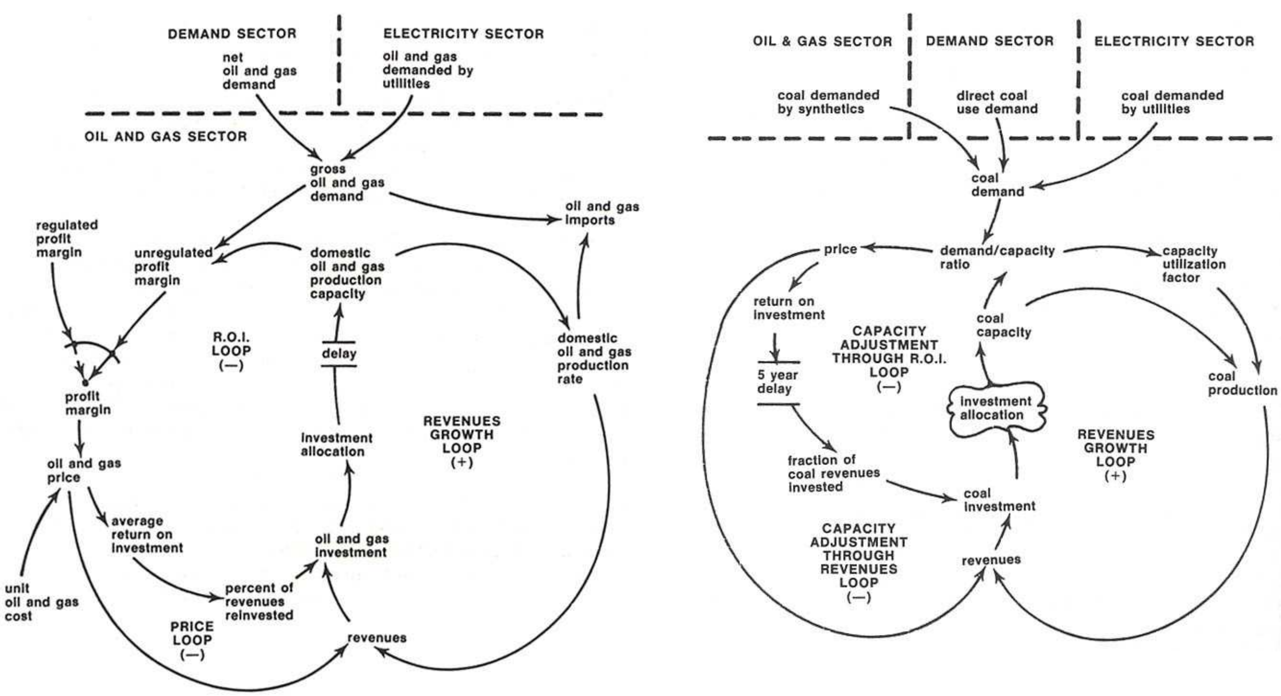


Figure 11: Relationship between resource depletion and productivity in the COAL2 model (Naill, 1977)[34]

For both the oil & gas and coal sectors, increased profits[35] tend to raise both revenues and return on investment, both of which then generate higher investments in oil & gas or coal production facilities.

[34] The left-hand figure is number 4-14 in Naill (1977), "Oil and gas financial structure", while the right-hand figure is number 6-11, "Financial structure of the coal sector"

Following a construction delay, the new facilities become part of the total production capacity. If capacity exceeds demand, resource prices decrease, which reduces investment by decreasing both revenues and the return on investment; eventually, the reduction in investment adjusts coal production capacity to demand. The price response is therefore part of *two negative feedback loops*. In addition to the price adjustment mechanism, changes in resource production amounts also affect investments, in the form of a *positive feedback loop*: increased production generates more revenue, which increases investment (all else being equal) and production capacity in turn.

For the coal sector, there are two delays. Coal investments – the fraction of revenues invested, multiplied by total coal revenues – do not respond immediately to an increase in the rate of return; instead, there is a delay. The reason that Naill (1977) gives is behavioural: investors are reluctant to change their past behaviour, given the uncertainty of future conditions (new environmental regulations, changes in world fuel prices, etc.). A construction delay, as in the oil & gas sector, then results in a 3- to 5-year lead time to open a new mine.

2.1.3 The TIME(R) Model

In the TIME model (de Vries and Janssen, 1997), resource dynamics are governed by two opposing effects: resource depletion and learning. Depletion results in rising costs of discovering and exploiting new resources as cumulative production rises. Technological innovation ("learning-by-doing") provides a countering effect, by lowering the required capital-output ratio. Coal mining is represented as two components – underground and surface mining – since TIME(R) is based loosely on COAL2 (Naill, 1977), while oil and gas are represented as an aggregate source. This section describes coal mining in detail.

The TIMER energy model (de Vries et al., 2001) describes the production of coal from surface and underground reserves[36] in all model regions, through investment based on their relative costs (as affected by labour costs and technological learning effects). On the basis of anticipated demand, "coal companies decide to invest in coal producing capacity. This planning is based on the desired coal production, which equals the domestic coal demand" and the net trade, includes an "overhead factor", and extrapolates over some time horizon according to the annual growth rate in the past 5-10 years (de Vries et al., 2001: 75), so that,

$$CP_{cap} = [(1+\theta) \cdot CP_{demand} + CP_{trade}] \cdot (1+z)^{\tau_H}$$

where CP_{cap} is the coal production capacity (GJ yr^{-1}), θ is the "overhead factor" (set to 0.1), CP_{demand} is the coal demand (GJ yr^{-1}), CP_{trade} is the amount of coal (GJ yr^{-1}) traded to the region in question, z is the annual growth rate, and τ_H is the time horizon (5-10 years).

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[35] Note that, because COAL2 focuses on the domestic US economy, import oil and gas prices provide a *price ceiling* for the potential prices charged for domestic fuels.

[36] According to de Vries et al. (2001: 73), "Coal reserves can be mined in various ways. Traditional ways are underground mining with room-and-pillar methods (50-60% recoverable) and with mechanised long- and shortwall mining (60-90% recoverable). Surface (or opencast) coal mining has become more important due to technological progress, lower labour requirements and economies of scale in surface mining techniques. Recoverability is high (>90%). However, without proper restoration after exploitation, environmental impacts are severe. Between 1970 and 1995, world-wide the share of surface mining increased from 30% to 42%."

The most important short-term loop is the demand-investment-production-price loop: "Given a demand for solid fuels, 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 ratio operations on the basis of the production cost ratio" (de Vries and Janssen, 1997: 95). Depletion and learning affect the fuel price through longer-term loops, and price then affects demand in the longer-term as well. The overall feedback structure for coal production in TARGETS is shown in Figure 12 (copied from Figure 5.4 in de Vries and Janssen, 1997) – "UndCoal" is underground coal, while "SurfCoal" is surface-mined coal; "SF" means "solid fuel", or coal.

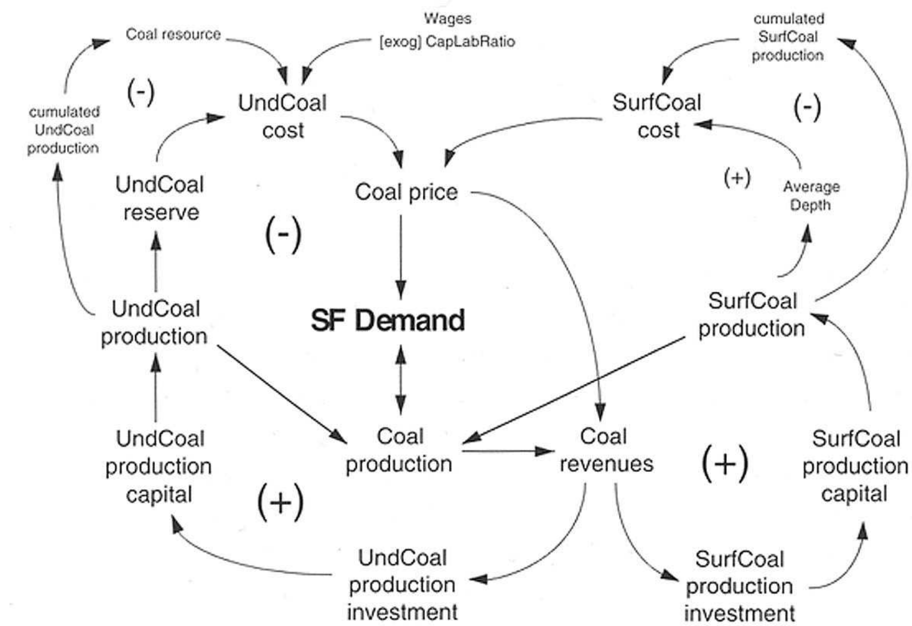

Figure 12: The demand-investment-production-price loop in TIME(R)

In TIMER, investment in additional mining capacity depends on an indicator widely used in the mining industry: the desired Reserve to Production Ratio, RPR_{des}. If RPR_{des} exceeds RPR_{act}, exploration effects are accelerated. Required investment is then allocated to surface or underground mining based on the desired coal production level and on the rate at which existing mining capacity is retired. New mining capacity is first ordered and then constructed with a delay of 3-5 years. Underground mining is determined based on a Cobb-Douglas production function in labour and capital, and includes a depletion-based multiplier term.

Investments add to the coal-producing capital stocks, which produce output on the basis of capital-output ratios, γ_{prod}. These ratios depend on three trends (de Vries and Janssen, 1997: 97):

- "As exploration proceeds, newly discovered deposits tend to be of lower quality (deeper, harder to reach, smaller amounts). To model this effect, γ_{prod} is divided by a depletion-cost multiplier (<1);

- In labour-intensive underground mining, labour productivity increases over time as more capital per labourer is used (Cobb-Douglas); the capital-labour ratio is an exogenous input;
- Over time, the capital costs to find and produce one unit of coal decline because of technological progress. The underground mining sector models this effect through capital-labour substitution. The surface mining sector models the effect by multiplying γ_{prod} by a technology factor (<1), which is a function of cumulative production."

2.1.4 The DICE Model

Earlier versions of DICE (e.g. Nordhaus and Boyer, 2000) did not contain an energy sector, but instead modelled emissions as a function of economic output and of emissions-reduction taxes. A Cobb-Douglas production function likewise represented total economic output.

The newest version of DICE, called *DICE-2007* (Nordhaus, 2008), is different. Apparently, it introduces an explicit representation of energy, and models economic output as a function of capital, labour, and energy.[37] I have been unable to find this explicit energy sector in Nordhaus (2008), and the output and emissions equations remain basically the same as in Nordhaus and Boyer (2000):

$$Q(t) = \Omega(t)[1 - \Lambda(t)]A(t)K(t)^{\gamma}L(t)^{1-\gamma}$$
$$E_{Ind}(t) = \sigma(t)[1 - \mu(t)]A(t)K(t)^{\gamma}L(t)^{1-\gamma}$$

where $\Omega(t)$ is the climate damage term, $\Lambda(t)$ is the abatement costs, $A(t)$ represents technological change, $K(t)$ is global capital, $L(t)$ is the global labour, $\sigma(t)$ is the carbon intensity level, set exogenously, and $\mu(t)$ is the emissions reduction rate.

Unlike earlier versions, DICE-2007 includes energy considerations in two places: as a backstop technology, and through depletion. According to Nordhaus (2008: 42),

> A new feature of the DICE-2007 model is that it explicitly includes a *backstop technology*, which is a technology that can replace all fossil fuels. The backstop technology could be one that removes carbon from the atmosphere or an all-purpose environmentally benign zero-carbon energy technology. It might be solar power, or nuclear-based hydrogen, or some as-yet-undiscovered source. The backstop price is assumed to be initially high and to decline over time with carbon-saving technological change. The backstop technology is introduced into the model

[37] The DICE-2007 model has not been described in either this document or any other documents I have written about energy modelling to this point, so a brief description, which is taken verbatim from Nordhaus (2008), follows. According to Nordhaus (2008: 34), "Output [in DICE-2007] is produced by a Cobb-Douglas production function in capital, labour, and energy. Energy takes the form of either carbon-based fuels (such as coal) or non-carbon-based technologies (such as solar or geothermal energy or nuclear power). Technological change [is exogenous, and] takes two forms: economy-wide technological change and carbon-saving technological change… Carbon fuels are limited in supply. Substitution of non-carbon fuels for carbon fuels takes place over time as carbon-based fuels become more expensive, either because of resource exhaustion or because policies are taken to limit carbon emissions. One of the new features of this round of the DICE model is an explicit inclusion of a backstop technology for non-carbon energy. This technology allows for the complete replacement of all carbon fuels at a price that is relatively high but declines over time."

by setting the time path of the parameters in the abatement-cost equation so that the marginal cost of abatement at a control rate of 100 percent is equal to the backstop price for each year.[38]

In terms of depletion, DICE-2007 imposes a limit on the total available fossil fuel resources through this equation,

$$CCum \leq \sum_{t=0}^{T_{max}} E_{Ind}(t).$$

The total resources of economically available fossil fuels are set to six trillion metric tonnes (Nordhaus, 2008: 57). Furthermore, "the DICE model assumes that incremental extraction costs are zero and that carbon fuels are optimally allocated over time by the market, producing the optimal Hotelling rents" (Nordhaus, 2008: 43). In other words, the Hotelling rents generated by the constraint eventually drive consumption to the backstop technology.

Nordhaus (2008) does not provide particulars on the Hotelling rent or other model calculations, but he does provide the model code free-of-charge (in the GAMS programming language) on his website, http://www.econ.yale.edu/~nordhaus/homepage/DICE2007.htm.

2.1.5 The Second Generation Model (SGM)

The SGM is a computable general equilibrium model designed to analyze issues related to energy, economy, and greenhouse gas emissions. It models energy production and use in considerable detail[39]: "Since CO_2 is the most important greenhouse gas and energy the overwhelming determinant of anthropogenic CO_2 emissions, model design gives special prominence to treatment of the energy production, transformation and use" (Edmonds et al., 2004: 8). A set of production functions determine all *production* in the model, where the output, Y, of the production activity depends on a series of inputs, X_i, so that,

$$Y = F(X_1, X_2, X_3, \dots, X_n)$$

The inputs, X_i, come from all (or a subset) of the 21 economic sectors in the model. The function $F(\,)$ is different for each output, Y, and may be a relatively simple CES production function or a more sophisticated, hierarchical formulation – production functions, vintaged capital, profits from resource and goods production, and depletion mechanisms (very simple) are described in detail in Chapter 6 of Brenkert et al. (2004).

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[38] According to Nordhaus (2008: 52), the calculated cost of the backstop technology starts at roughly \$1200 tonne^{-1} and decreases to about \$950 tonne^{-1} by 2100. The values are based on work by Jae Edmonds and the IPCC; they may appear high, but recall that they represent the cost of removing the *last* tonne of carbon from emissions, not the first – i.e. cheaper options are also available and are exhausted first.

[39] SGM has 21 producing sectors [I count 20], according to Edmonds et al. (2004). In the following list, the energy-supply subset (eight parts) is italicized: *crude oil production*, *natural gas production*, *coal production*, *hydrogen production*, *electricity production*, *oil refining*, *natural gas distribution*, paper and pulp, chemicals, primary metals, food processing, other industry and construction, the service or everything else sector, passenger transport, freight transport, grains and oil crops, animal products, forestry, *biomass production*, and other agriculture.

The Second Generation Model represents energy reserve production explicitly, and determines its change over time through a CES production function. The depletion mechanism for reserves is relatively simple, and is described in Brenkert et al. (2004: 55): resource *depletion* in the current time period is for *consumptive* purposes, and so depletion = consumption.

In terms of calculation, consumption is based on the anticipated energy demand for the next five year period (SGM works on five-year timesteps). A check ensures that this "anticipated consumption" does not exceed the available production; if it does, demand is reduced to match the production capacity. Finally, energy resource levels are decreased to match the amount of energy consumed.

Capital investments are vintaged, which complicates the mathematical expressions in SGM considerably. Investments into energy production capital[40] are given by Brenkert et al. (2004: 72), and the calculations are relatively elaborate; however, the most important two equations are the investment in fossil fuel production (eq. 122),

$$Eqdep_j = xnp_j \cdot \alpha_{0,j,jj,v} \cdot Z_{j,jj,v} \cdot \alpha_{i=26,j,jj,v}^{1/(1-\rho)} \cdot KA_{j,jj,t} \qquad OR$$
$$I_j = \tau_{K_j} \cdot Tech_{j,v} \cdot Z_{j,v} \cdot KA_{j,t}$$

where the top and bottom equations are identical, with the top equation taken from Brenkert et al. (2004: 72), and the bottom a re-expression of the top equation rendered into more familiar terms. The second subscript, *jj*, is eliminated in the bottom equation because fossil fuel production has no subsectors. In terms of symbols, I_j is the total investment in sector *j*, τ_{K_j} is the lifetime of the capital, $Tech_{j,v}$ represents technological change, $KA_{j,t}$ is the capital of vintage v currently installed (a new vintage enters existence at each five-year timestep), and $Z_{j,v}$ "incorporates the participation of the variable factors, [and] is calculated with expected prices in the expected profit equation and implemented with long-run elasticities" (ibid., 2004: 72). The "participation of variable factors" is given by,

$$Z_{j,jj,v} = 1 - \left(\alpha_{0,j,jj,v} \cdot Pe_{j,jj}\right)^{\mu} \cdot \sum_{i=1}^{N-1} \left(\alpha cst_{i,j,jj,v} \cdot {Pie_{i,j,jj}}^{-\mu}\right)$$

where $Pe_{j,jj}$ is the expected commodity price, $Pie_{i,j,jj}$ is the expected price paid, μ is a function of the long-run elasticity, and $\alpha cst_{i,j,jj,v}$ equals $\left({\alpha_{0,j,jj,v}}^{\rho} \cdot \alpha_{i,j,jj,v}\right)^{1/(1-\rho)}$ and represents technical change.

2.2 Energy Reserves and Extraction in the Model

The model currently simulates energy reserves of coal, crude oil, and natural gas, as well as additions through new reserve *discoveries*, and reductions of reserve levels through *extraction* and *fuel use*

[40] Investments into electricity production are discussed earlier in Chapter 8 of Brenkert et al. (2004), and are simpler to represent.

(2.2.1). Based on energy demand, it then adjusts reserve production capital and thus capacity (2.2.2). Finally, the results of the modelling approach are shown in section 4.1, below.

Note that energy demand is currently prescribed from historical figures (EIA, 2006), but will eventually be simulated as part of the economic sector to incorporate feedbacks between energy supply and demand. Therefore, the modelling of energy reserves and extraction is reactive in terms of *demand-supply* rather than feedback-based at present.

2.2.1 Non-renewable Energy Reserves

Fossil fuels provide energy for both heat and electricity production (1.2). This section describes the manner in which I model fossil fuel reserves and their change over time in Vensim. The amounts of fossil fuels extracted depend on heat and electricity production (and thus *demand*), and so this section is linked with energy resource extraction capital and capacity (2.2.2), fuel prices (3.1), and electricity production (3.2).

Figure 13 shows the structure of the energy resources component of the energy sector in the case of *coal*: coal reserves, new discoveries, and depletion (through harvesting), as well as their means of depletion. The structures for oil and natural gas are identical, although names are different, of course.

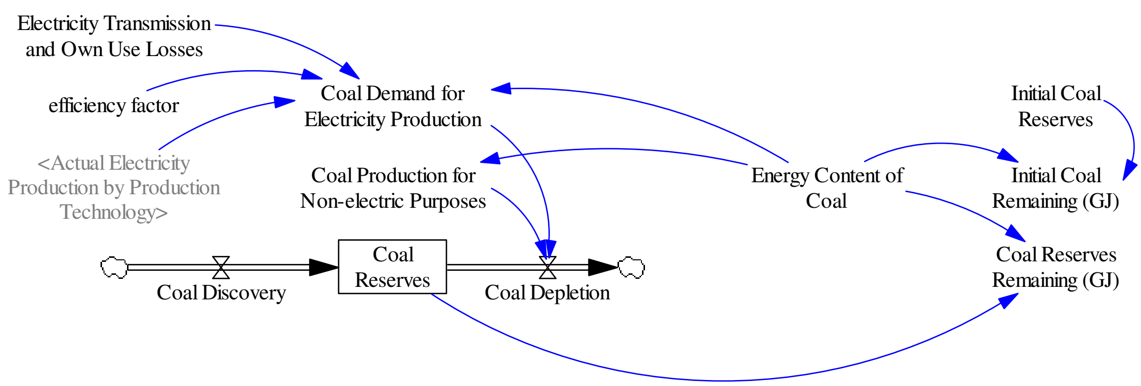

Figure 13: Coal reserves, discovery, and depletion, including the means of that depletion (in Mt)

In terms of equations, the reserves of all fossil fuels are given by,

$$R_i(t) = \int \left(R_{disc_i} - R_{depl_i}\right) dt$$

where $R_i(t)$ is the current energy source reserve, with initial values given in section 1.1.1, R_{disc_i} is the resource discovery rate, and R_{depl_i} is the calculated resource depletion rate. For oil and natural gas, discoveries have increased the reserve amount considerably over the past 25 years, while existing reserves of coal are already well known (WEC, 2007), and so have not increased. In the model, reserve discoveries are prescribed on the basis of historical figures (1980-2005) – the values used are presented in the "Energy Reserves" **MS Excel** database. Values for discoveries beyond 2005 have not been included, but possible *resource* amounts are provided in section 1.1, and simulations could investigate the effects of different assumptions about the extents of real-world resources and their conversion through economic or technological means, or simply through "unanticipated" discoveries.

Calculation of the depletion rate is somewhat more complicated, as is evident from Figure 13, and depends on fossil fuel extraction and use for 1) fossil fuel-fired electricity production (2.2.1.1), and 2) non-electric energy production (2.2.1.2). The total extraction of energy from any fossil fuel source has this form,

$$R_{depl_i} = RE_{elec_i} + RE_{heat_i}$$

where R_{depl_i} is, again, the depletion rate (in Mt yr^{-1}, MB yr^{-1}, or Tm^3 yr^{-1} for coal, oil, and natural gas, respectively), RE_{elec_i} is energy resource extraction for electricity production (same units), and RE_{heat_i} is for non-electric (heat) resource extraction (same units).

2.2.1.1 Resource Extraction for Electricity Production

Several electricity production technologies use fossil fuels. Resource extraction for electricity has the following form,

$$RE_{elec_i} = \left(\frac{1}{\varepsilon_i} + \lambda_i\right) \cdot \frac{ElP_i}{EC_i}$$

where RE_{elec_i} is the resource extraction for electricity production (again, in Mt yr^{-1}, MB yr^{-1}, or Tm^3 yr^{-1} for coal, oil, and natural gas, respectively), ε_i is the efficiency of electricity production (set to 40% for non-renewable sources, and to 100% for renewables[41]), λ_i is the transmission and own-use losses of electricity production, which are significant [roughly 15% in the OECD countries and as much as 25% on average in non-OECD nations, according to Table 4 (taken from IEA, 2005)], ElP_i is the actual production of electricity from resource *i* (in GJ yr^{-1}; see section 3.2), and EC_i is the energy content of resource *i* (in various units, GJ t^{-1}, MJ bbl^{-1}, or MJ m^{-3}, depending on the type of resource). Clearly, some conversion factors are required, depending on units, but these are not complicated.

2.2.1.2 Resource Extraction for Non-electric Energy Production

Fossil fuels are also used for heat production. To meet heat-energy demands, energy extraction occurs according to the following equation,

$$RE_{heat_i} = EP_i / EC_i \cdot \alpha_i$$

where RE_{heat_i} is the resource extraction for heat-energy production (again, in Mt yr^{-1}, MB yr^{-1}, or Tm^3 yr^{-1} for coal, oil, and natural gas, respectively), EP_i is the actual primary energy production, which is the

[41] The efficiency of non-renewable energy production should actually not be set to a constant value, since it has increased over time in the real-world. Changes in efficiency are a result of technological progress, and so are actually endogenous (0). For the sake of simplicity, they are treated as constant values here.

minimum of the fuel-specific primary energy demand (ED_{heat_i})[42] and the energy production capacity (EP_{cap_i}), or,

$$EP_i = MIN\left(ED_{heat_i}, EP_{cap_i}\right)$$

EC_i is the energy content of fuel type *i*, given in GJ t^{-1}, MJ B^{-1}, or MJ m^{-3}, for coal, oil, and natural gas, respectively, and α_i is a unit conversion factor (for ones to millions of units, and so on). In general, the use of a $MIN(\,)$ function does not cause problems because the demand is almost always lower than the supply capacity; however, in some unusual cases, the fuel demand spikes and the production capacity is unable to meet the new, sharply higher level, because capacity increases are purely *reactive* rather than anticipatory. When this situation occurs, the $MIN(\,)$ function ensures that unavailable capacity is not used. In Vensim, energy production is modelled as in Figure 14. Note the overlap between the "*Resource-type* Production for Non-electric Purposes" variables in Figure 14 (the location of the calculation) and the non-electric energy production/extraction term in Figure 13, above (the location of the variable's use).

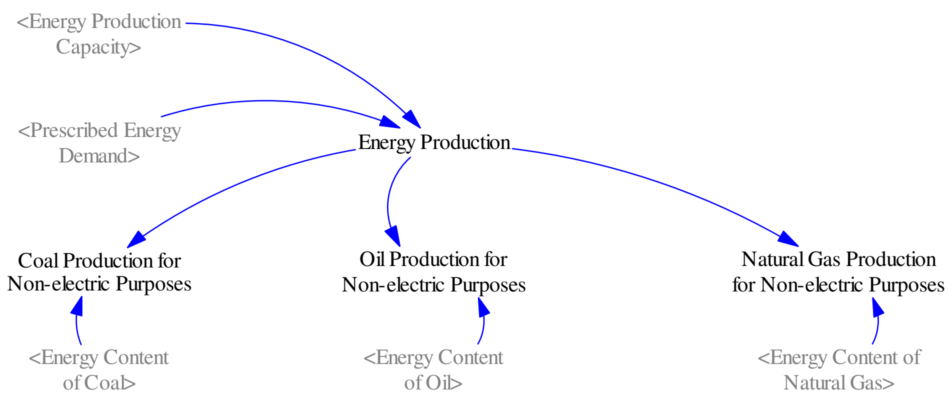

Figure 14: Basic calculation procedure for energy production (GJ yr^{-1}) and conversion to fuel extraction units (Mt yr^{-1}, MB yr^{-1}, and Tm^3 yr^{-1})

2.2.2 Energy Resource Extraction Capital

Energy demand fluctuates over time, as shown by the historical global extraction values for coal, oil, and natural gas from 1980-2005 (EIA, 2006) of Figure 15, below. These fluctuations, and particularly the large and rapid changes evident in the coal demand values, have significant effects on the modelling of energy-extraction capital requirements. A further complication for modelling is the "capital construction pipeline": resource extraction capital must be ordered, built, and installed, which introduces a delay – of 3-5 years in TIMER, for example – into the production process.

[42] Note that, once energy demand is calculated rather than exogenous (at present, I have simply assumed that *historical production = energy demand*), it is important to include an overhead factor, as in de Vries et al. (2001), because not all energy extracted is used to meet demand; instead, some is waste, and some is used to transport the extracted fossil fuels to their destinations.

These demand fluctuations and capital construction delays mean that excess capacity is a necessity. This section describes the capital construction pipeline (2.2.2.1), and a preliminary approach towards determining capital requirements, their connection to resource prices, and investment in new extraction capacity (2.2.2.2). The equations and relationships used are relatively simple, and can be improved if necessary.

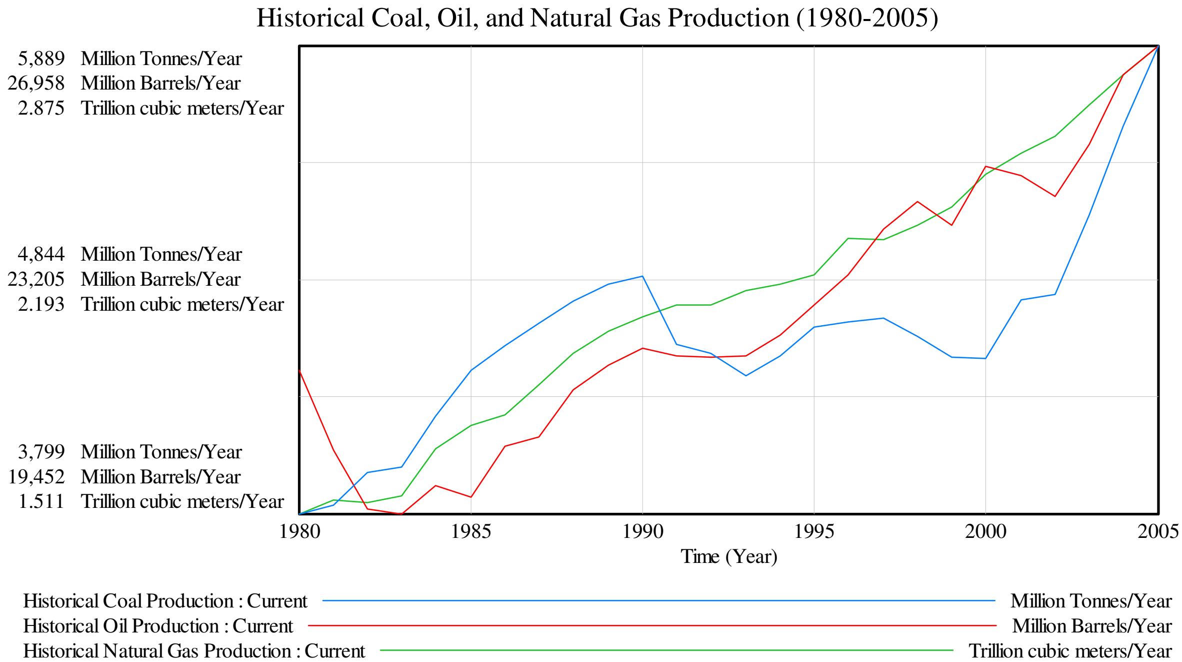

Figure 15: Historical fossil fuel extraction values from EIA (2006)

2.2.2.1 The Construction Pipeline

The representation of the energy-resource extraction-capital stock has two parts in the model, as shown in Figure 16: 1) capital under construction, and 2) production capital. Note the similarity to the electricity production pipeline in Figure 33 (3.3.1).

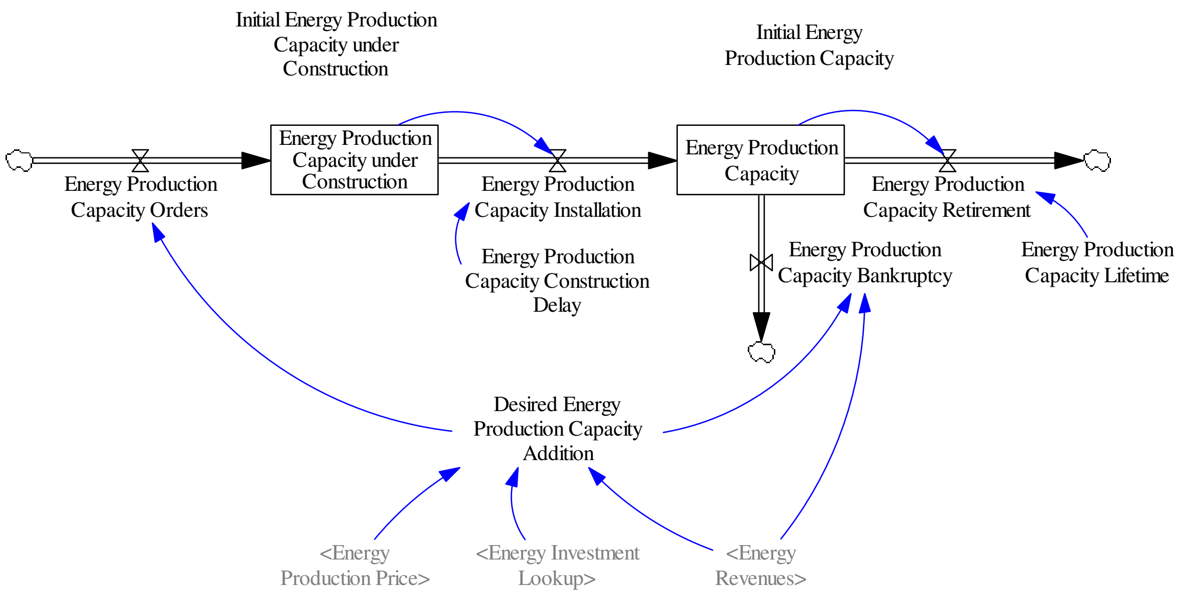

Figure 16: Basic calculation procedure for energy resource extraction capital changes (GJ yr^{-1})

Two of the flows that connect the stocks in Figure 16 are straightforward, and have this form, *flow* = *stock/residence time*, where the residence times are either the construction delay or the capital lifetime. However, two others are more complicated: the *production capacity orders* flow, which determines the amount of capital under construction, and the *energy production capacity bankruptcy* flow, which eliminates unprofitable capacity from production at an earlier date than its age would otherwise retire it.[43]

In terms of the extraction capacity orders, they are set to meet the desired additions to energy extraction capacity, so long as the desired additions are positive,

$$EP_{cap\_orders_i} = MAX\left(EP_{des\_cap_i}, 0\right)$$

where $EP_{cap\_orders_i}$ is the capacity orders (GJ yr^{-1}), and $EP_{des\_cap_i}$ is the desired energy production capacity addition (GJ yr^{-1}). The $MAX(\,)$ function ensures that orders are positive. Calculation of $EP_{des\_cap_i}$ is the culmination of the next section, and the energy extraction capacity bankruptcy calculation is closely related. Both rely, of course, on extraction revenue and its consequent investment in more capacity. The extraction capacity orders accumulate in the stock on the left side of Figure 16, which represents the energy production capacity under construction, $EP_{cap\_constr_i}(t)$, given by,

$$EP_{cap\_constr_i}(t) = \int \left(EP_{cap\_orders_i} - EP_{cap\_install_i}\right) dt$$

[43] The bankruptcy mechanism in the SGM (Brenkert et al., 2004) provided the impetus for including bankruptcy here, although the approach to the elimination of bankrupt capacity is different between the two models.

where $EP_{cap\_install_i}$ is one of the two straightforward flows and represents the energy production installed in the current time step (in GJ yr^{-1}).

The maximum energy production capacity, EP_{cap_i}, is,

$$EP_{cap_i}(t) = \int \left(EP_{cap\_install_i} - EP_{cap\_retire_i} - EP_{cap\_bankrupt_i}\right) dt$$

where $EP_{cap\_retire_i}$ is the other straightforward flow and represents the energy production capacity removed from the production capital stock in the current time period (in GJ yr^{-1}), and $EP_{cap\_bankrupt_i}$ is the energy production capacity lost to bankruptcy, in the case that overcapacity decreases market prices of resource *i* below production costs (in GJ yr^{-1}) – see below for its equation.

2.2.2.2 Investment in Resource Extraction Capacity

Figure 17 shows the basic structure of energy prices, profits, and investment in new energy extraction capacity – note that energy production is repeated here from Figure 15, and the calculation method for the desired energy production capacity addition (see also Figure 16) is also shown. Calculations of these variable values and explanations of their means of interaction are described in this section.

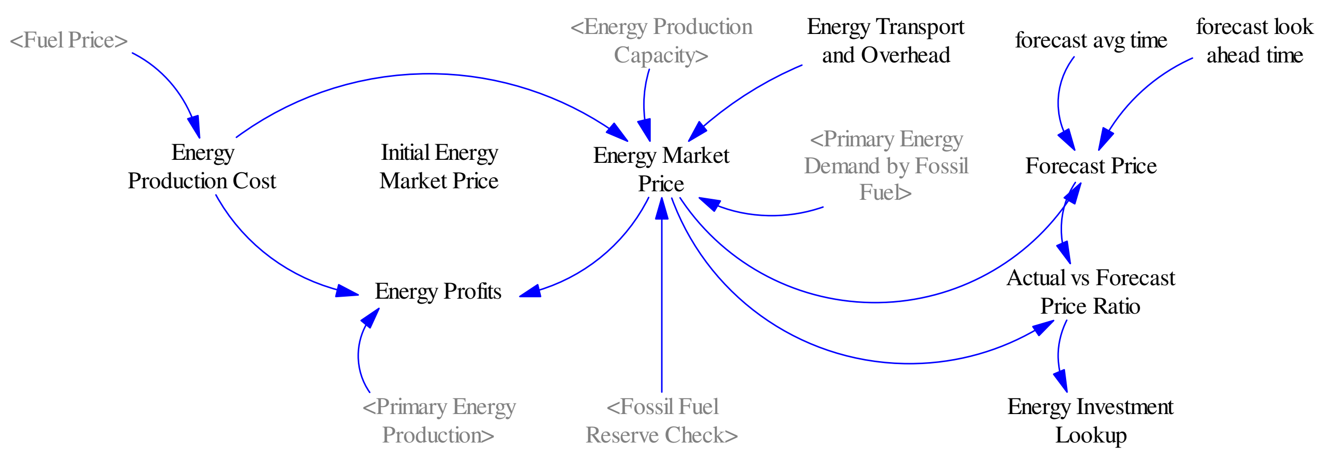

Figure 17: Basic calculation procedure for energy production and market prices, extraction profits, and price forecasting

Investment in new extractive capacity depends on its profitability, which depends in turn on the difference between market prices for energy resources and their production costs, and on the amounts of resources extracted. I assume here that production costs are relatively stable compared with market costs, and that they vary only with technological progress (which lowers production costs), and with resource depletion (which raises costs). ***Production cost*** calculations are described in section 3.1, below.[44]

[44] Use of the same production costs for both heat- and electric-energy requires one important, and probably false, assumption. In the case of heat-energy, fossil fuel costs as calculated in section 3.1 are taken to represent their actual *base production costs*. In the case of electric-energy, the fossil fuel costs represent the majority of the *variable costs* portion of

Market prices are generally at least slightly higher than production costs because of expenses related to transportation and storage, and vary according to the difference between supply capacity and energy demand: high demand and relatively low supply means higher prices, while low demand and high supply capacity means lower prices. These dynamics are captured very simply in the model at present[45], as,

$$MP_i = \mu_i \cdot PC_i \cdot \left(\frac{ED_i}{EP_{cap_i}}\right)$$

where MP_i is the market price for fossil fuel *i* ($ GJ^{-1}), PC_i is its production cost ($ GJ^{-1})[46], μ_i is the transportation and storage adjustment (currently set to 1.2), ED_i is the energy demand (GJ yr^{-1}), and EP_{cap_i} is the maximum energy resource extraction rate (GJ yr^{-1}). See also Figure 17, above.

Idle, unprofitable extraction capital is retired when the market price falls below the production cost, so that, after a delay, the market price corrects to or above the production cost – this retirement of idle capital occurs through the *energy production capacity* ***bankruptcy*** flow (see Figure 16), and has the following equation,

$$EP_{cap\_bankrupt_i} = IF\ THEN\ ELSE\left(EP_{profit_i} < 0, \left|EP_{des\_cap_i}\right|, 0\right)$$

where $EP_{cap\_bankrupt_i}$ is the early retirement of unprofitable energy extraction capital (GJ yr^{-1}), the "$IF\ THEN\ ELSE(\,)$" function is a built-in Vensim operation[47], and the EP_{profit_i} is the annual profit ($ yr^{-1}) for the energy extraction sector as a whole. The equation begins by checking whether energy extraction is profitable in the current year (market price > production cost). If producers are losing money ($EP_{profit_i} < 0$), an amount equal to the absolute value of the desired capacity addition, $EP_{des\_cap_i}$, is retired immediately. Again, the desired capacity addition, $EP_{des\_cap_i}$, is explained below. The effect on energy extraction capacity levels of including bankruptcy is considerable, as shown in

---

annual electricity plant operating costs (total cost = fixed + variable costs). Thus, while the calculated fuel costs represent the *production costs* in one case (*heat-energy*), they represent the *market price* in the other case (*electric energy*). Yet, these prices are different under almost all circumstances.
The solution, of course, is to use the market price calculation described in this section for the electric plant operating costs too, which will probably be the eventual approach. For now, however, I want to determine the adequacy of the market-price calculation described here before applying it sector-wide. Further, it is at least somewhat reasonable to expect the electricity sector to suffer slightly less from volatile prices, because electricity plants buy their fuel on a quarterly cycle (according to Fiddaman, 1997), and may also have long-term contracts that shield them from some volatility.

[45] I also fully expect the formulation of market prices to change; however, this equation is simply the first approach that includes what I believe to be the main factors in determining market prices.

[46] In FREE, *PC* is called *PP*, or the "production price". The *production cost* equation used here is adapted from FREE.

[47] The if-then-else operator can also be written as "IF THEN ELSE(*condition*, *if true*, *if false*)". It works by first checking the *truth* condition in the left-most position, and then using the middle value (usually a *variable* value) if the condition is true, or the right-most value (either a *constant* or another *variable*) if the condition is false.

Figure 18, and ensures that changes in the availability of extraction capacity follow changes in demand more closely.

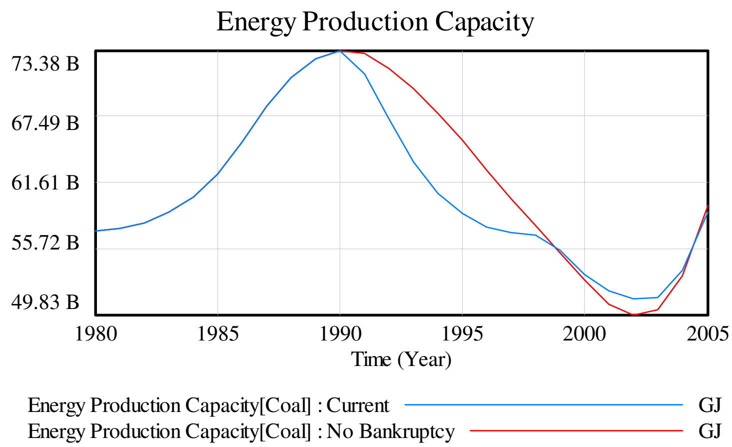

Figure 18: Effects on energy extraction capacity levels of including capital bankruptcy

The ***energy profits*** depend, of course, on the difference between the market price of energy and its production cost. Energy profits are given by,

$$EP_{profit_i} = (MP_i - PC_i) \cdot EP_i$$

where EP_{profit_i} is the annual profit (\$ yr^{-1}) for the extraction of fuel source *i*, $MP_i - PC_i$ is the difference between the market fuel price and its production cost (\$ GJ^{-1}), and EP_i is the actual energy production (GJ yr^{-1}), defined above.

Investments into additional energy resource extraction capacity are made according to the potential profitability of that additional capacity. To determine this future profitability, there are three options:

1. Use the current price as the basis of profitability calculations;
2. Use the trend in market prices over the past *x* years; or,
3. Use the trend in market prices to forecast future market prices *x* years into the future.

Ideally, expected prices would include the effects of anticipated policies, but these feedbacks are not yet included.

In terms of actual modelling, I use the third approach because I believe it more accurately represents real-world decision-making approaches[48]. The following calculations represent a first attempt at capturing some of the behaviour that affects investment into extraction capacity. I explain the reasons for my modelling choices and demonstrate that the results they produce are reasonable; however, *suggestions as to alternative approaches are welcome*.

[48] Although, of course, *expectations* – in the sense of altered behaviour in light of planned events, like an impending imposition of carbon taxes, the announcement of forthcoming subsidies, or the anticipated release of a new technology – are not included.

Vensim offers a simple representation of price forecasting based on past changes in the price,

$$Var = FORECAST\left(Input, \tau_{past}, \tau_{forecast}\right)$$

where Var is the variable being forecast, $Input$ is the variable whose behaviour is used for generating the forecast, τ_{past} is the period (years) used to generate forecast values, and $\tau_{forecast}$ is the number of years into the future to forecast the value of Var. Not surprisingly, forecasting does not work very well at turnarounds, either undershooting or overshooting the actual values, but its failure in this regard is actually desirable, because people do not generally anticipate or understand turnarounds well either. In the case of the model, the market price is forecast into the future, and this forecast value is used for decisions about extraction capacity additions,

$$MP_{forecast_i} = FORECAST(MP_i, 10, 5)$$

where $MP_{forecast_i}$ is the market price of fuel *i* forecast five years into the future based on ten years of market price fluctuations. Changes in the time periods used do not influence model performance greatly, although shorter timeframes for τ_{past} tend to increase model fluctuations, as would be expected.

Investment then occurs on the basis of a comparison between current and forecast market prices: if prices are currently relatively low but are forecast to rise, investment is likely to produce higher returns and is thus desirable; however, if prices are currently good but are expected to decline, investors may wish to hold on to their money. In other words, when $MP_{forecast}/MP > 1$, investment will occur at its maximum, and when $MP_{forecast}/MP < 1$, investment will fall relative to its possible maximum. This possible maximum is the total profit from energy resource extraction. A *lookup table* in Vensim captures the desirable investment relative to its maximum, and consists of the values in Table 17.[49]

Table 17: Lookup table for investment multiplier values

$MP_{forecast}/MP$	0.6	0.9	1.0	1.5	2.5
Multiplier	0.1	0.8	0.9	1	1

The effect of this forecast and investment lookup is relatively small, as shown in Figure 19 for coal extraction capacity. The effects for oil and natural gas extraction are similar, with reduced capacity for the "investment lookup" as compared with the "no investment lookup" case for oil, and with alternating maximum values for natural gas, as in the case of coal.

[49] Again, the values used here are purely conjectural and should be revised, if evidence of real-world investment behaviour is available and suggests other behavioural patterns.

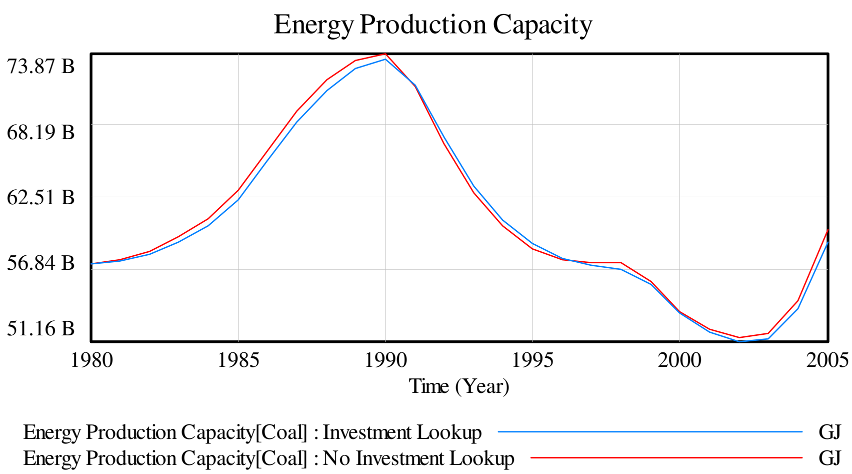

Figure 19: Effects on energy extraction capacity of market price forecasting and investment lookup table

Finally, the ***desired energy extraction capacity addition***, $EP_{des\_cap\ i}$, serves two purposes. It determines both the amount of the extraction profit that should be allocated to new extraction capacity construction, and the amount of capital retired early through bankruptcy, if the market price falls below the production cost. The desired capacity addition is calculated as,

$$EP_{des\_cap_i} = \lambda_{MP\_lookup} \cdot EP_{profit_i}$$

where λ_{MP_lookup} is the lookup of $MP_{forecast}/MP$ values (see Table 17), and EP_{profit_i} is the profit from energy extraction. Clearly, $EP_{des\_cap_i}$ can have either a positive or a negative value, depending on energy extraction profits. When positive, $EP_{des\_cap_i}$ becomes the production capacity orders (GJ yr^{-1}), $EP_{cap\_orders_i}$; when negative, it becomes the amount of extraction capacity lost to bankruptcy.

2.2.3 Possible Inclusions in Next Model Draft

The COAL2 model (Naill, 1977) has several assumptions that may be worth adoption here:

1. The addition of a synthetic fuel as a substitute for oil (and gas); however, its inclusion would complicate the model considerably, and the same effect can be obtained by implementing a backstop technology (although coal reserves would not be depleted as in COAL2 in this case);
2. The inclusion of a productivity-depletion dynamic. In COAL2, productivity drops as remaining resource pools become smaller, so that ever more capital (and expenditure) is required to extract the same amount of resource. However, the fuel prices as calculated already include this effect in a slightly different functional form from COAL2's lookup tables (see Figure 9), where the fuel price is calculated (see 3.1.3) as
$$FC_i = h/yr \cdot \left(fc_i(0) \cdot \left(\frac{R_i}{R_i(0)} \right)^{\rho} \right);$$
3. Investment in resource extraction never uses 100% of profit. Instead, investment is based on the *average rate of return* and on *profits*. In profitable times, 30% of internal revenue may be invested in greater capacity, and very profitable times may draw an additional 30% from

external sources. So my investment multiplier values in Table 17 are wildly optimistic; however, using an approach like Naill's led to underinvestment in the maximum coal production capacity;

4. The entirety of each energy resource may never be extractable. For example, in the case of coal, existing mining methods normally permit only 50% of underground coal resources and 90% of surface resources to be recovered – in the case of underground mining, about half of the coal is left in underground mines to support the roof. Thus, it may be important to differentiate explicitly in the model between energy *resources* and energy *reserves*.

COAL2 also faced the same types of problems as this model has in terms of responding to rapid changes in demand (especially in the coal sector):

1. A *startup problem*: the industry is unable to increase its output fast enough to keep up with accelerating demand;
2. A *depletion problem*: the depletion of [less expensive] surface resources creates an accelerated demand for underground coal that exceeds the expansion capability of the underground coal industry.

3. Electricity Production

This section discusses **electricity production**. Its starting point is the modelling of energy resource extraction and use for electricity production: the primary energy supply (2.2). Data on current electricity production, production capacity, capital costs, and capital lifetimes presented above (1.2.3) reveal changes over time as a result of investment in different electricity-production technologies. Such investment depends on electricity prices (3.1), and consequently changes the mix of electricity production options (3.2), fuels required, efficiency of production (technology), and energy-production costs. Electricity production costs affect, in turn, the capacity utilization by production-technology (3.3) – whether coal-fired, oil-fired, nuclear, or other – and the technological mix in the longer term.

3.1 Electricity Prices

From a simulation perspective, electricity prices are critical for two reasons: they determine the overall growth in electricity-producing capital stock over time, and they determine investment priorities for future power plant construction. In terms of the first point, if electricity is considerably more expensive than other energy sources, its production capacity will not expand. This relative expansion effect will be modelled at the whole energy-sector level. Second, as explained in the investment section (3.2) below, less-expensive electricity production options are generally favoured over more expensive alternatives.

This section describes several alternative approaches to fuel pricing (3.1.1), before developing two alternative approaches for use in the model. The first alternative approach employed by the model is based loosely on Fiddaman's (1997) FREE model (3.1.2), while the second approach uses an adaptation of the *screening-curve* approach typically used in the power plant planning methods of electrical engineering (3.1.3). For the sake of transparency, the model uses the second, screening-curve, approach.

3.1.1 Alternative Approaches to Pricing

The sections below describe energy pricing in FREE (Fiddaman, 1997), TIME (de Vries and Janssen, 1997; de Vries et al., 2001), EPPA (McFarland et al., 2004; Paltsev et al., 2005), GTEM (Pant, 2007), and SGM (Brenkert et al., 2004; Edmonds et al., 2004).

3.1.1.1 The FREE Model

Energy pricing in FREE is described in detail in Appendix C, page 162, below. In summary, Fiddaman's (1997) energy price equation looks complicated,

$$IP_i = PP_i \left(\frac{AC_i}{PP_i}\right)^{\gamma_a} \left(\frac{MC_i}{PP_i}\right)^{\gamma_m} \left(\frac{EO_i}{NEP_i}\right)^{\gamma_d}$$

where AC_i is the average cost of energy production, MC_i is the marginal cost of energy production, EO_i is the energy orders, NEP_i is the normal energy production, and the gamma parameters (elasticities) are the weight to average cost (γ_a), the weight to marginal cost (γ_m), and the weight to demand pressure (γ_d). However, because of parameter settings, the equation simplifies considerably.

In FREE, the gamma parameters are set to 1, 0, and 2, respectively, so that

$$IP_i = PP_i \left(\frac{AC_i}{PP_i}\right)^1 \left(\frac{MC_i}{PP_i}\right)^0 \left(\frac{EO_i}{NEP_i}\right)^2 = AC_i \cdot \left(\frac{EO_i}{NEP_i}\right)^2 = \left(\frac{VC_{SR\,avg_i} + KE_{cost_i}}{M_{RE_i}}\right) \cdot \left(\frac{EO_i}{NEP_i}\right)^2$$

which actually makes a great deal of sense, in most ways – although see Appendix C for notes.

With these parameter settings, the pricing equation states that 1) costs have two components, goods and capital costs, 2) costs depend on the availability of resources (more resources reduce costs), and 3) costs increase nonlinearly with demand – i.e. if the ratio of energy orders to normal energy production rises quickly, the price of energy increases quickly as well. I have trouble, however, with point 2: I would have thought that variable costs are sensitive to fuel depletion and saturation, rather than both variable costs *and* capital costs being depletion- and saturation-sensitive.

3.1.1.2 The TIMER Model

The TIMER model equations for variable cost prices are provided in de Vries et al. (2001, Chapter 5). The coal component (or *solid fuels*) component of TIMER is based on earlier work by Naill (1977) and the US Department of Energy (AES, 2000) – see de Vries et al. (2001) for further information on its predecessors. Contrary to our model, coal resources in TIMER are broken into two parts based on the harvesting method: surface and underground mining, which has a considerable impact on recoverability of the resource and on the environment.

In TIMER, **coal prices** depend on labour costs, technological learning, and depletion. Base coal demand depends on demand for non-energy purposes, for electricity production, and for energy conversion processes, as well as on transformation losses between distribution nodes and domestic end-use. Then, on the basis of anticipated demand, coal companies decide to invest in *coal producing capacity*. Anticipated demand is based on the growth rate over the last 5-10 years of the simulation. To calculate the production costs, de Vries et al. (2001: 76) use a Cobb-Douglas production function with a substitution coefficient between labour and capital and a depletion multiplier, which is a function of the fraction of cumulative production plus identified reserve on one side, and the initial resource base on the other. A required labour-capital ratio is calculated that adjusts the workforce and simulates the effects of mine mechanization.

The equations for the cost of underground coal production take this form,

$$Cost_{UC} = (Wage_{UC} + a \cdot RKLR) \cdot (RLS_{US}/CPC_{UC})$$

where $Cost_{UC}$ is the cost of underground coal production, $Wage_{UC}$ presumably represent the wages paid to labour, $RKLR$ is the required labour to capital ratio (calculated based on some sort of undefined optimization procedure), RLS_{US} is the required labour supply, defined below, and CPC_{UC} is the production capacity of underground coal. The required labour supply, RLS_{US} is defined as,

$$RLS_{UC} = L(0) \cdot \left(\frac{CPC_{UC}}{CPC_{UC}(0)}\right)^{1} \cdot \left(\frac{RKLR}{RKLR(0)}\right)^{-\theta} \cdot \left(\frac{DepMult_{UC}[1-(CP_{CumUC}+IR_{UC})/R_{UC}(0)]}{DepMult_{UC}[1-(CP_{CumUC}(0)+IR_{UC}(0))/R_{C}(0)]}\right)^{\frac{1}{1-\theta}}$$

where $L(0)$ is the initial labour supply, θ is the labour-capital substitution coefficient, $DepMult_{UC}$ is a depletion multiplier function that relates cumulative production (CP_{CumUC}) and the identified reserves (IR_{UC}) to the initial coal resource base (R_{UC} and R_{C}).

The equations for surface coal are somewhat simpler, since labour is not so expensive here. Then, a weighted average of underground to surface coal production and prices gives the average resource price.

3.1.1.3 The EPPA Model

According to McFarland et al. (2004: 689), EPPA uses bottom-up engineering models (models that represent numerous generation/industrial technologies explicitly, as well as their substitutions/substitutability) to determine relative costs of electricity. It then uses CES functions with pre-set elasticities and per-fuel share values in capital, O&M, and fuel costs – see Table 3 of McFarland et al. (2004) – to model shifts between various electricity production options or industrial technologies. From McFarland et al. (2004), it seems that fuel costs are pre-set rather than calculated, but Paltsev et al. (2005: 30) write that “All fossil energy resources are modeled in EPPA4 as graded resources whose cost of production rises continuously as they are depleted.” Therefore, it seems that energy prices increase with depletion, but that substitutions between fuel sources are based on CES functions, as described above.

3.1.1.4 The Global Trade and Environment Model (GTEM)

According to Pant (2007), producers maximize profits and take prices as given. Each region has *n* production sectors that produce single products using all commodities and four factors of production (capital, labour, natural resources, and land). Electricity production is modelled as a special case with a homogeneous output but non-homogeneous technologies (nuclear, coal-fired, hydro, and so on). A technology bundle approach is used, where a Leontief production function represents each production technique. The documentation is complicated enough for this model that I gave up trying to find equations for fossil-fuel prices.

3.1.1.5 The Second Generation Model (SGM)

According to Edmonds et al. (2004), there are 21 producing sectors in the SGM, of which there are four larger "aggregates"[50]: energy production and transformation, industry, transportation, and agriculture. Electrical power generation is treated in detail (Edmonds et al., 2004: 8).

Since, like the other CGE-based models described above, SGM uses CES and Leontief production functions, the factors of production can vary with price according to the elasticity of substitution. As Edmonds et al. (2004: 15) explain,

> The demand for each input to the production process can be derived as a function of its price and the price of all other inputs. This is expressed mathematically in [the equation below], which describes the demand for factors of production per unit output (input-output coefficients) as a function of prices,
>
> $$a_{ij}(\vec{p}) = \alpha_{0j}^{-r}\alpha_{ij}^{-r}\left[\frac{p_j}{p_i}\right]^{1-r}$$
>
> where a_{ij} is the amount of input *i* required per unit of output *j*. Note that these CES input-output coefficients always depend on prices. Also note that the above equation uses subscripts for inputs and outputs, except for the exponent *r*. This exponent actually does vary by producing sector, but subscripts on *r* have been suppressed. Finally, the corresponding CES production function has this form,
>
> $$g(\vec{p}) = \frac{1}{\alpha_0}\left[\sum_{i=1}^{N}\left(\frac{p_i}{\alpha_i}\right)^r\right]^{\frac{1}{r}},$$
>
> where [g is not defined,] $r = \rho/(\rho - 1)$, and p_i is an element of the price vector $\vec{p}$. [Note that the α terms are calibrated constants that seem to represent technological progress.]

Critically, Edmonds et al. (2004: 18) write that energy prices are basically unpredictable:

> There is no well defined method for determining price and policy expectations, though there are competing representations. In fact, there is no reason to presume that one set of model derived parameters can accurately predict expectations for future prices or policies. The prediction of price and policy expectation remains as much an art as a science.

3.1.2 FREE-based Approach to Pricing

This approach is based loosely on energy pricing in FREE (see Appendix C, page 162). Energy prices have two parts here: variable costs and fixed costs; the variable costs equation also has two parts: 1) fuel prices, and 2) variable operation and maintenance prices. In equation form, $VC_i = FC_i + OM_{var_i}$, where VC_i is the cost of variable inputs, FC_i is the current fuel cost for resource *i*, and OM_{var_i} is the variable operations and maintenance cost for electricity-generating technology *i* – its values are prescribed based on Table 8.7 of Shaalan (2001).

[50] Inserted for explanatory rather than modelling purposes.

As a stop-gap measure only, the fuel pricing equation takes this form at present,

$$FC_i = fc_i(0) \cdot \left(\frac{R_i}{R_i(0)}\right)^{\rho}$$

where $fc_i(0)$ is the initial price of the resource, R_i and $R_i(0)$ are the current and initial reserve levels, and ρ is a resource coefficient that is set to approximately the same value as Fiddaman's (1997) resource coefficient, γ. For coal, oil, and natural gas, γ = -0.4285; my corresponding coefficient value is ρ = -0.4 – I could have used the same value, but decided to opt for simplicity.

The corresponding capital cost equation has two parts: 1) capital installation costs and 2) fixed operation and maintenance costs. It takes this form,

$$KP_i = \frac{(r + 1/\tau_i) \cdot KE_i + \varphi_i \cdot KE_{cap_i}}{(\varsigma_i/\varsigma_T) \cdot NEP_i}$$

where KP_i is the annualized capital cost, based on the first terms in parentheses (interest rate, r, and capital lifetime, τ_i), KE_i is the current total investment into electricity-capital (installed capital), φ_i is a parameter based on Tables 8.3 and 8.7 of Shaalan (2001) that represents the fixed operation and maintenance costs ($ GW^{-1} yr^{-1}), KE_{cap_i} is the installed electricity capacity (GW), NEP_i represents the benchmark electricity production[51], and the ς_i and ς_T terms represent the current resource-specific and total market shares of electricity by fuel type – these values are prescribed at present, but the next section describes how market shares are made endogenous.

3.1.3 Screening Curve-based Approach to Pricing

Following the same two-part calculation approach for electricity production costs, but using the screening curve approach described in Shaalan (2001) leads to slightly different values. This screening curve approach is preferable because the model already calculates electricity capital costs (see section 3.3.1, below), which renders the use of NEP unnecessary. If I choose to model the sorts of construction-capacity scarcities for which the NEP variable accounts, I can simply use a multiplier-type variable.

According to Shaalan (2001), there are five main components in constructing a screening curve.

1. Fixed annual costs (capital costs);
2. Fixed operation and maintenance costs;
3. Cost per year at capacity factor of zero (fixed capital plus O&M costs);
4. Fuel costs; and,
5. Variable operation and maintenance costs.

[51] This value is currently set to the historical energy production by technology/fuel type, but will eventually represent a value similar to the *NEP* value that Fiddaman (1997) uses.

The representation in Vensim of these screening curve components, and the flow of information through the associated calculations, is shown in Figure 20. Illustrative results of the screening curve approach for thermal energy sources are shown in Figure 21. Note that the modelling approach for non-renewable energy resources is described in section 2.2, above.

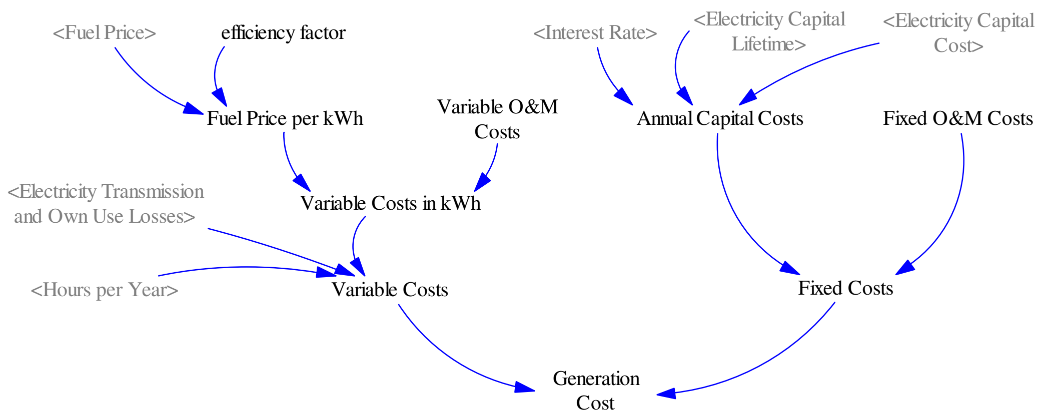

Figure 20: Basic calculation procedure for electricity production costs (in \$ kW^{-1} yr^{-1})

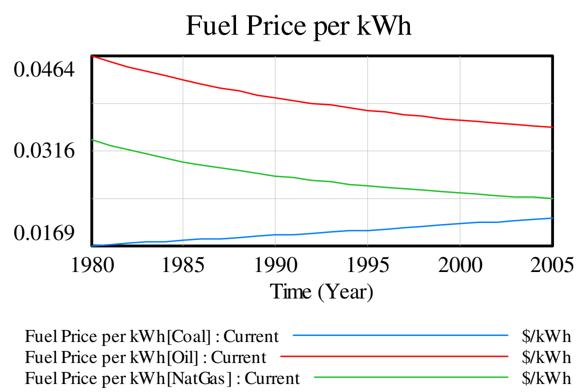

Figure 21: Fuel prices per kilowatt-hour, as calculated from the simple screening-curve approach

Calculation of the fixed annual capital costs is straightforward. The model already keeps track of average capital costs for each of the current, major electricity production technologies in the "Electricity Capital Cost" variable (section 3.3.1). To determine the *annual* component of this cost requires the global *interest rate* and the lifetime of each technology:

$$KC_i = (r + 1/\tau_i) \cdot KE_{cost_i}$$

where KC_i is the annualized cost of capital (in \$ kWyr^{-1}), r is the interest rate (prescribed as 6%), τ_i is the capital lifetime (also prescribed), and KE_{cost_i} is the electricity capital cost (in \$ kW^{-1}; see 3.1.4).

The fixed O&M costs are given by Shaalan (2001) in Tables 8.3 and 8.7, also in \$ kWyr^{-1}. Of course, the sum of the fixed annual and fixed O&M costs yields the cost per year at a capacity factor of zero, such that,

$$\mathfrak{F}C_\mathrm{i} = KC_i + OM_{fix_i}$$

where $\mathfrak{F}C_\mathrm{i}$ is the fixed price for technology *i* (I ran out of useful Latin symbols), and OM_{fix_i} is the fixed operation and maintenance cost.

Shaalan (2001: 8.14) then determines the total fuel costs from the "raw" cost of the fossil fuel (or nuclear fuel), its energy content, and the amount used. The form of the calculation is,

$$fc_i(0) = RP_i/FE_i \cdot UHR_i$$

where $fc_i(0)$ is the base fuel cost ($\$\ kWh^{-1}$), neglecting the effects of depletion, RP_i is the resource price (in $\$\ t^{-1}$, $\$\ bbl^{-1}$, or whichever unit is appropriate), FE_i is the fuel unit energy content ($MJ\ t^{-1}$, $MJ\ bbl^{-1}$, and so on), and UHR_i is the unit heat rate, which represents the total heat input ($MJ\ h^{-1}$) to the system divided by the net electric power generated by the plant (kW).

Shaalan's (2001) approach poses one problem: I do not have heat input rates or net power generation values, since I am not building an single, independent power plant[52]. Therefore, I cannot easily calculate *UHR*. Instead, I can calculate the fuel costs in the same units as Shaalan (2001), so long as I have, 1) a GJ to kWh conversion factor, and 2) the efficiency factor for each plant type. Part 1 is straightforward, because the model already calculates fuel unit prices in $\$\ GJ^{-1}$, based on an initial price of non-renewable resources and their heat content. The required conversion factor is 1 kWh = 3.6 MJ. For part 2, we recognize that all the fuel input to an electric plant does not result in useful energy production – electricity production for all technologies has an efficiency rating generally less than 40% (although efficiencies are increasing) – which drives up the fuel cost per kWh of electricity produced. For the time-being, I have prescribed efficiency factors of 40% for all non-renewable fuel uses, but these values could be made to increase endogenously through *technological change*. Therefore, the fuel price equation takes this form,

To complete the calculation, we multiply the number of hours per year by the annual capacity factor to yield the number of hours the plant was in operation, and this factor then determines the total fuel costs:

$$FC_i = h/yr \cdot \left(fc_i(0) \cdot \left(\frac{R_i}{R_i(0)}\right)^{\rho} \right)$$

where FC_i is the total fuel cost (now including depletion), $fc_i(0)$ is, again, the initial fuel cost (neglecting depletion) in $\$\ kWh^{-1}$, *h/yr* is the number of hours per year (set to $8760\ h\ yr^{-1}$), and the last bracket is the depletion effect, explained in section 3.1.2. The calculation is based on a 100% capacity utilization, as in Shaalan (2001).[53]

[52] The purpose of a screening curve is to aid selection of the best plant-type for a particular location and context.
[53] For the comparison between the generation costs of different technologies to be valid, the same capacity utilization value has to be used for all technologies. Otherwise, a positive feedback results, which installs only high fuel-cost, low capital-

The variable O&M costs are also given by Shaalan (2001) in Table 8.7, also in \$ kW^{-1} yr^{-1}, so that the total variable prices are,

$$VC_i = FC_i + h/yr \cdot (OM_{var_i})$$

where VC_i is the variable cost for technology *i*, and OM_{var_i} is the variable operation and maintenance cost, multiplied here by the capacity factor to determine total yearly costs.

Finally, the fixed and variable costs can be added together to get the price per year of any electricity generation option. In other words, the average generation cost (*GC*) is,

$$GC_i = \mathfrak{F}C_i + VC_i$$

and is measured in \$ kW^{-1} yr^{-1}.

Problems with the Approach
The total generation costs take the *current* fuel and fixed prices without any expectation of future values, and both change, of course. So either ***expectations*** must be built into this version of fuel and fixed cost pricing, or a new pricing structure is necessary.

3.1.4 Electricity Capital Cost

Electricity capital costs significantly affect generation costs of different electricity production technologies, and are not static over time. In fact, many capital costs have changed considerably (1.2.3.2)[54], and the model must be able to simulate the effects of such changes on investment decisions over time. The current approach is to prescribe changes in electricity capital costs, but a preferable approach would be to simulate the effects of technological change on capital costs instead.

For the *capital costs* in Figure 22, the stock represents the current cost, by technology/fuel type, for each kilowatt of additional capacity. The "electricity capital cost" stock can change, through its flows, because of cost increases from increased regulation, changes in policy, or materials shortages, for example, and can decrease because of policy or regulatory changes and, more importantly from a

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cost plants that, because of their high fuel costs, are never used (actual capacity utilization is decided elsewhere), while the high-capital cost, low-fuel cost stock decreases (more costly capital and, because of high use, costly fuel as well) but is used at full capacity (again, because of relatively low fuel costs) until it disappears.
Note that I have used the approach of Shaalan (2001) of *prescribed*, *identical* utilization values of 100% for all electricity production technologies. However, there are many available values, from low to high. With low utilization values, technologies with cheaper capital-costs and more costly fuel will be constructed, while capital-intensive technologies will not be installed, despite their cheaper fuel. High utilization values favour high capital-cost, low fuel-cost technologies. Instead of 100%, it would, of course, be possible to experiment with mid-range capacity utilization values to see the effect on technology selection.

[54] For example, in the case of natural gas, capital costs in 1980 were roughly \$800 kW^{-1} but have since fallen to approximately \$550 kW^{-1}, while nuclear energy capital costs began at roughly \$225 kW^{-1} but have risen since to ten times as much.

modelling viewpoint, because of technological change. Therefore, the structure shown in the figure allows for slightly different rates of cost decreases between *endogenous* and *exogenous* energy demands, because of the different behaviours associated with each (see Chapter 3, section 0).

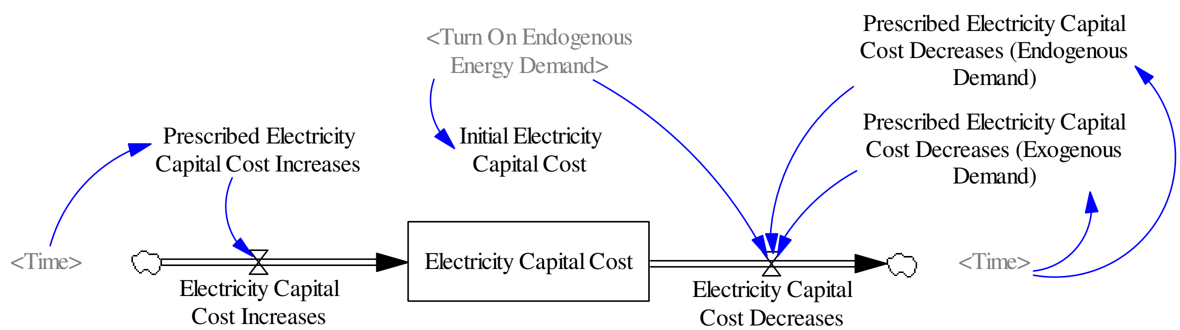

Figure 22: Basic calculation procedure for *electricity capital cost* (in \$ kW^{-1})

The electricity capital cost equation is,

$$KE_{cost_i}(t) = \int \left(KE_{cost\uparrow_i} - KE_{cost\downarrow_i}\right)$$

where $KE_{cost\uparrow_i}$ and $KE_{cost\downarrow_i}$ are, respectively, the increase or decrease in the capital cost of technology *i* over time (in \$ kW^{-1}). These changes are currently *prescribed* from historical data, with the values shown in Figure 23.

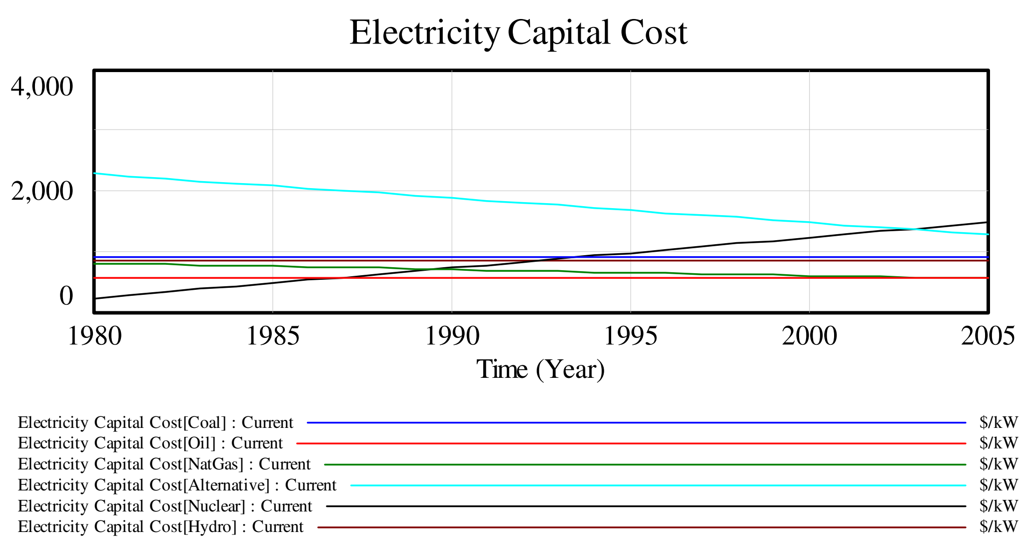

Figure 23: Prescribed changes in electricity capital costs over time (in \$ kW^{-1})

3.2 Investment in Electricity Production Capacity

Hoogwijk (2004: 19) – who is part of the IMAGE team – writes that the *investment strategy* for electricity production capacity is based on changes both in relative fuel prices and generation costs (3.1) of thermal and non-thermal power plants, while the *operational strategy* (3.3.2) determines how much of the installed capacity is used and when, based on the *variable costs*. In other words, investment decisions consider both capital costs and variable costs, while operational decisions consider only the variable costs.

Investment has two components: a desired electricity production level, and desired electricity-production technologies. In terms of desired production, investment occurs both to meet the projected need and to replace the retired capacity (3.2.1). For investment to exceed the level required to replace retired electricity-production capital, there must be some anticipation of future electricity needs.[55]

Of course, the retired capacity need not be replaced with exactly the same generation technology, and new investment will be allocated to the most suitable – i.e. least-cost, generally-speaking – generation technology. The treatment of allocation algorithms in Vensim is discussed in section 3.2.3. For several reasons described below, allocation of invested funds is not always based on market mechanisms, but can instead be a product of government policy. Therefore, while market mechanisms, in the sense of Hoogwijk (2004), determine investment in thermal and alternatives-based electricity production capacity (3.2.4), political decisions are responsible for the expansion of nuclear and hydroelectric capacities (3.2.5). Their sum yields the total annual investment in electricity production capacity (3.2.6).

3.2.1 Anticipation of Future Needs

Plans for expansions in the electricity production capacity rely on the historical record: expansion decisions over the previous *x* years determine the planned expansions for the next *y* years.[56] To implement this planning approach, the model calculates the *desired new electricity production capacity* – its associated structure in Vensim is shown in Figure 24.

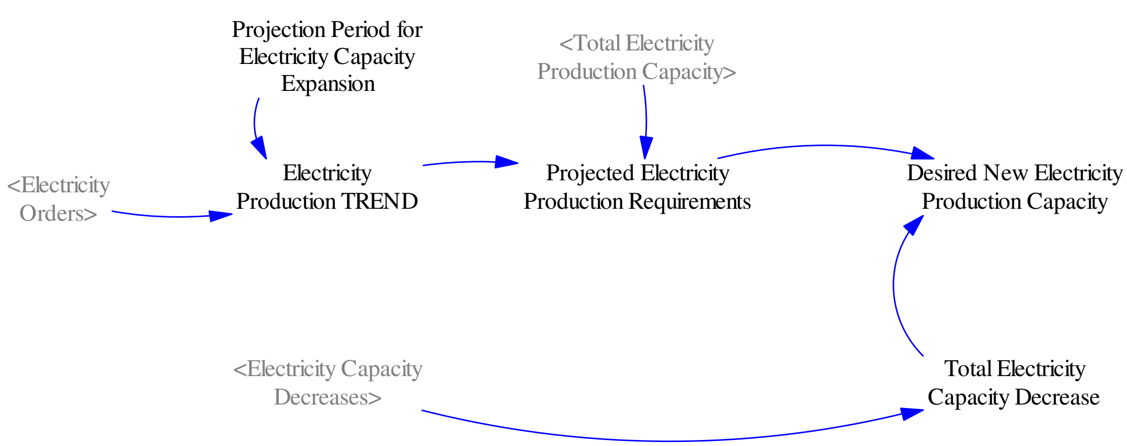

Figure 24: Basic calculation procedure for *desired new electricity production capacity* (GW yr^{-1})

[55] COAL2 takes a slightly different approach: investment in new electricity capacity in that model occurs when the capacity utilization factor is greater than 55% (see Naill, 1977).

[56] Strange as this seems, there is reason to believe that electricity capacity planning actually does follow this general approach.

At present, *electricity orders* is an exogenous variable – it is simply the historical electricity production, since the model only runs to 2005 currently. Of course, even when the electricity orders is an endogenous variable, it will still be determined elsewhere in the model, so using the orders as an input here is appropriate.

As stated above, to "anticipate" future demand for electricity production, the model checks the past *x* years (currently set to five) to see the rate of growth in demand. This *x-year* average rate of growth is multiplied with the current capacity to determine necessary additions to the maximum production capacity. Furthermore, it is necessary to replace retired electricity production capital. Taking these factors together, the desired additions to production capacity take this form:

$$\frac{dKE_{cap\_des}}{dt} = TREND(EO, \tau_{EO}) \cdot KE_{cap} + \sum_i KE_{cap\_retired_i}$$

where dKE_{cap_des}/dt is the desired change in electricity production capital (in GW yr^{-1}), $TREND(\,)$ is a built-in Vensim function that provides a very simple, fractional rate of change for a variable – in this case, EO, the energy orders – and that only works for positive trends, τ_{EO} is the number of years to check, KE_{cap} is the total installed electricity capacity, and $\sum_i KE_{cap\_retired_i}$ is the production capacity retired in the current year that must be replaced.

3.2.2 Determination of Available Investment Funds

All of the desired electricity production capital cannot necessary be built in reality, since the required investment funds may not be available. The current approach to calculating available funds is very simple, and is intended simply as a place-holder for a more detailed representation. Its structure is shown in Figure 25.

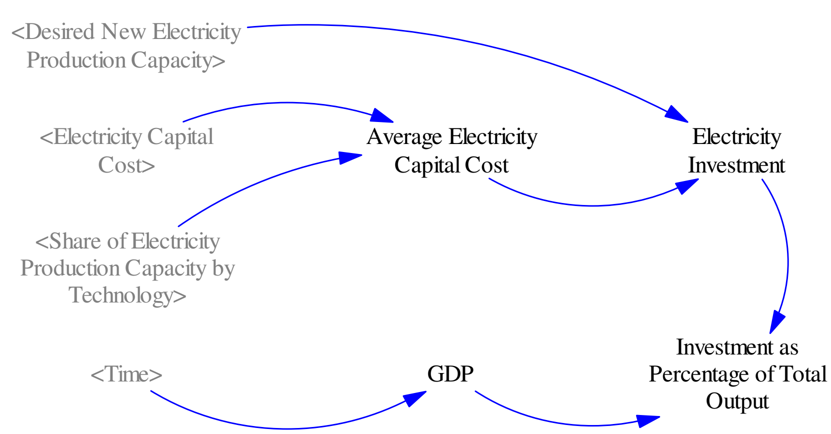

Figure 25: Basic calculation procedure for *electricity investment* (in 10^9 \$ yr^{-1})

The current *electricity investment* depends on the desired change in electricity production capital, dKE_{cap_des}/dt, measured in GW yr^{-1}, and on the average cost of the electricity capital, KE_{avg_cost}, in

$ kW^{-1}. The basic assumption here is that funds are always available for investment in capital, since whatever capacity is desired receives funding for capital based on the current capital costs. The equation for electricity investment is, therefore,

$$Inv_{Market} = \frac{dKE_{cap\_des}}{dt} \cdot KE_{avg\_cost}$$

where Inv_{Market} is the monetary value of funds invested in increasing the maximum electricity production capacity through a *market-based* approach (in 10^9 \$ yr^{-1}), dKE_{cap_des}/dt is the desired change in electricity production capital (in GW yr^{-1}), and KE_{avg_cost} is the average cost of electricity capital (in \$ kW^{-1}). Some unit conversion is also clearly required. Note that this approach requires an important assumption: market-based investments meet anticipated future needs, while prescribed investment sums (for nuclear and hydroelectric power) are determined through different means.[57] In other words, the total invested in increasing the maximum electricity production capacity is,

$$Inv_T = Inv_{Market} + Inv_{Prescribed}$$

where Inv_T is the sum invested (in 10^9 \$ yr^{-1}) in increasing the electricity production capacity of all technologies, Inv_{Market} is calculated as above, and $Inv_{Prescribed}$ is the sum invested in increasing the nuclear and hydroelectric production capacities (in 10^9 \$ yr^{-1}), which is prescribed by decision-makers, rather than on the basis of anticipated future needs.

The average cost is calculated according to the following equation,

$$KE_{avg\_cost} = \sum_{\forall i} \varsigma_i \cdot KE_{cost_i}$$

where KE_{cost_i} is the capital cost for electricity production technology *i* (in \$ kW^{-1}; see section 3.1.4), ς_i is the market share of technology *i* (3.3.3), and *i* represents the available electricity production technologies, of which there are six.

[57] This assumption has important implications for model behaviour. If the *desired change in electricity production capital* value is chosen to represent the *total* desired capacity increases (thermal, alternative, nuclear, and hydroelectric), the calculated investment sum must be divided in two parts: allocation by market-based methods (to thermal power and alternative sources), and allocation by prescription (to nuclear and hydroelectric power). Then, the investable sum for market-based methods is relatively small, and the simulated thermal and alternative maximum production capacities are consequently smaller as well. If the desired change in electricity production capital value is chosen to represent "economically reasonable" capacity expansions – and nuclear and hydroelectric power projects are assumed to be undertaken for different reasons, whether strategic, social, or environmental, and so on – then the investable sum for market-based allocation is significantly larger, and the simulated maximum production capacities match historical figures more closely. (Although, of course, the model can be recalibrated so that the first approach yields better values.)

An additional consequence is that, after 2005, when investment into greater nuclear and hydroelectric production capacities are assumed to be allocated by a market approach, the funding for expansion of the maximum electricity production capacity falls, since $Inv_{Prescribed}$ now equals zero, and $Inv_T = Inv_{Market}$.

3.2.3 An Introduction to Allocation Algorithms in Vensim

Vensim also has a function for allocating scarce resources, called *allocate by priority*. Allocate by priority has this form,

$$allocated[x] = ALLOCATE\ BY\ PRIORITY(request[x], priority[x], size, width, available)$$

where $allocated[x]$ is the amount of *available* resource given to requester x, where each requester is a member of the array $[x]$. The *size* parameter is the number of elements in the array, which is six, in our case ($coal$, oil, …, $hydro$), $width$ is the sensitivity of the algorithm to differences in priority, where smaller values lead to more exclusivity (i.e. $request[x_1]$ may get all of the available resource) and larger values lead to more sharing (a $width$ of ∞ will share all of the available resource evenly among all requesters). The Vensim manual does not make the nature of $width$ clear, but my guess is that it is a basically a standard deviation. Critically, $width$ can be a variable rather than fixed value.

The most complicated argument to $allocate\ by\ priority$ is the $priority$ variable itself, which is basically a ranking of importance, or *priority*. So each subscript in the $priority[x]$ array has a unique value (in theory, although one priority can be equal to another in practice[58]) that affects how much of its associated $request$ is filled.

Note that $allocated$, $request$, and $priority$ are all arrays with the same number of subscripts.

3.2.4 Least Cost-based Investment

To determine the best allocation of desired electricity plant construction between the various options, I use the *allocate by priority* function.

Some important assumptions are necessary:

1) As stated above, nuclear and hydro electricity plants are not allocated in this manner (although it is still necessary to account for all investment funds allocated to these sectors, simply to make sure that money is not double-counted).[59] Thus, where the discussion below includes index *i*, *i* refers to coal, oil, natural gas, and alternative sources, but not to nuclear and hydroelectric power. The treatment of nuclear and hydroelectric capacity expansion is discussed in section 3.2.5;
2) For thermal and alternative energy technologies, the plant choice is determined in terms of the *current* generation cost, as suggested by Hoogwijk (2004), without consideration of trends or expectations (see the explanation of the *generation cost*, *GC*, in section 3.1.3); and,

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[58] In a case of equivalency, the amount allocated to each of the equal-priority requests will be identical. For example, suppose the requests for x_1 and x_2 are 10 widgets, and the total available is 10 widgets. If *priority*$[x_1]$ = *priority*$[x_2]$ = 7 (a nonsense value), then *allocated*$[x_1]$ = *allocated*$[x_2]$ = 5, so long as *priority*$[x_1]$ = *priority*$[x_2]$ > *priority*$[x_n]$ for all $n \neq 1, 2$. Of course, if *priority*$[x_1]$ = *priority*$[x_2]$ < *priority*$[x_n]$, again for all $n \neq 1, 2$, and *width* is very small, their requests may be neglected (*allocated*$[x_1]$ = *allocated*$[x_2]$ = 0), and the equivalency of their *priority* values may have no importance.

[59] For the time being, such investment will be treated separately from the investment approach documented here – i.e. the *available* investment funds treated in this section will not be used for both market-based and subsidized electricity plant construction. Subsidized construction will be assumed to have obtained its funding elsewhere.

3) The value for the $width$ variable can be chosen in such a way as to properly represent real-world decisions. As stated above, $width$ plays a very important role in determining the actual allocations, but the manner in which it works is not totally clear.

The allocation procedure has the following steps:

1. Identification of the optimal electricity production capacities by the available electricity production technologies (in this case, coal-fired, oil-fired, natural gas-fired, and alternative sources);
2. Allocation of available investment funds to the desired electricity production technologies;
3. Entering of the investment funds into the construction pipeline, so that the desired production capacity becomes available, after the construction delay.

Steps one and two both use the $allocate\ by\ priority$ function.

Step one of the allocation procedure determines the *requests* for investment funds. It is the most complicated of the three steps, and has the most embedded assumptions. It has these constituent sub-calculations: a) the desired electricity production capacity by available electricity production technologies, b) the priority of these requests, c) the degree to which one request (of higher priority) will be favoured over other requests, and d) the amount of available resource to be allocated.

a. The *request* component of the $allocate\ by\ priority$ function is handled first. In general, the $request$ for construction of additional electricity production capacity for the thermal and alternative electricity production technologies is for the *entire* desired new electricity capacity. In other words, each of the thermal and alternative power-generation lobbies wants as much as they can get. However, there is one restriction: the expansion of each technology-type depends not just on its cost, but also on society's capability to build it.[60] To represent this capability for construction, the following logic, based on an *if-else* statement (or "if then else", in Vensim terminology), is employed,

$$\frac{dKE_{cap\_des_i}}{dt} = IF\ THEN\ ELSE\left(\frac{dKE_{cap\_des}}{dt} \leq KE_{cap_i}, \frac{dKE_{cap\_des}}{dt}, \frac{KE_{cap_i}}{3}\right)$$

where $dKE_{cap\_des_i}/dt$ is the *requested* additional capacity for technology *i* (GW yr^{-1}), dKE_{cap_des}/dt is the *total* desired change in electricity production capital (see section 3.2.1), and KE_{cap_i} is the current installed electricity capacity for technology *i* – pay careful attention to the indices in the equation. The effect of the equation is to restrict the maximum increase in

[60] This concept is what McFarland et al. (2004) call a *fixed factor* in their EPPA model. It would be possible to represent this sort of construction *capacity* in the construction cost (so that it rises precipitously), but I think such an approach would not represent reality as well as a *fixed factor* does. After all, a more immediate response to inquiries about over-running construction capacity would be '*it is not possible*', rather than '*it will cost you x-times as much*'. If engineers, technicians, designers, etc. are in short supply, they cannot be bought. In the long run, of course, the educational and employment systems will make more experts available and increase construction capacity.

the capacity of technology *i* to one-third[61] its current value, so that the capacity rises slowly. Note that this is a simple approach, and that more complicated structures like a *fixed factor*[60] (McFarland et al., 2004) are available.

b. Determination of the priority of the requests for new electricity production is the next step. Since the technologies with lower generation costs are preferable to those with higher costs per kWh, and since *allocate by priority* meets the requests with the highest priority value, it is necessary to convert high costs into low priorities. The approach is simple: I *invert* the generation cost, so that

$$p_i = 1/GC_i$$

where p_i is the priority for electricity production technology *i*. Values for p_i tend to be very small, because GC_i values are in the tens or hundreds of dollars per kW per year.

c. This calculation plays the critical role of *weighting* the allocation of electricity production capacity through the *width* argument to the *allocate by priority* function. It is possible to set a constant value for the width, but there is no guarantee that a pre-set value will behave in the same fashion throughout the simulation period. Instead, *width* can be set to match the behaviour of a key factor in the allocation. For the time-being, *width* is set to the maximum priority value, $p_{i\,max}$, or, in logical and Vensim terminology respectively,

$$w_{constr} = MAX(p_i) \text{ or } w_{constr} = VMAX(p[i!])$$

Of course, modifications to the basic form of this equation are possible – multiplication or division of the $MAX(\ )$ function result – but are not necessary until some form of calibration is undertaken.

d. The "scarce resource" to allocate in this case is the total desired change in electricity production capital, $dKE_{cap\_des_i}/dt$ (again, see section 3.2.1).

The results of these sub-calculations then feed into the *allocate by priority* function in the following manner:

$$\frac{dKE_{cap_i}}{dt} = ALLOCATE\ BY\ PRIORITY\left(\frac{dKE_{cap\_des_i}}{dt}, p_i, Hydro, w_{constr}, \frac{dKE_{cap\_des}}{dt}\right)$$

where dKE_{cap_i}/dt is the proposed expansion of electricity production capacity for technology *i* (in GW yr^{-1}), based on its cost of electricity production, *Hydro* is the last element of the electricity sources array, and the other arguments are described above.

[61] The value of one-third is chosen because it provides a relatively close match to historical growth patterns. The sort of approach taken here, allowing a growth per year of only 1/3 the current production capacity, is chosen for simplicity; however, as the model increases in complexity, a fixed-factor or similar approach may prove superior.

The proposed expansion of capacity, dKE_{cap_i}/dt, supposes that infinite funds are available for the construction. Of course, funding is often limited, and so **step two**, allocation of available investment funds, follows a similar procedure to the first step, and uses several variables from the first step as arguments to the second *allocate by priority* function. The output of the first step, dKE_{cap_i}/dt, becomes the *request* variable this time, after the following conversion:

$$\frac{dInv_{KEcap\_des_i}}{dt} = (1 + r_i)^{\tau_{kc}} \cdot KE_{cost_i} \cdot \frac{dKE_{cap_i}}{dt}$$

where $dInv_{KEcap\_des_i}/dt$ is the desired investment in the electricity production capacity of technology *i* (in 10^9 \$ yr^{-1}), the cost of electricity production capacity *i*, KE_{cost_i}, measured in \$ kW^{-1}, is explained in section 3.3.1, r_i is the fractional interest rate, and τ_{kc} is the construction period.[62] The only new introduction in step two is the amount of investment available for allocation to the requests for construction funding. In Vensim's terminology, the allocate by priority function then has this form,

$$\frac{dInv_{KEcap_i}}{dt} = ALLOCATE\ BY\ PRIORITY\left(\frac{dInv_{KEcap\_des_i}}{dt}, p_i, Hydro, w_{constr}, Inv_{Market}\right)$$

where $dInv_{KEcap_i}/dt$ is the amount of investment that technology *i* receives (in 10^9 \$ yr^{-1}), and Inv_{Market} is the total availability of market-based – i.e. non-nuclear, non-hydroelectric – investment funds for the year (in 10^9 \$ yr^{-1}).

The result of steps one and two is the structure in Figure 26, from Vensim, and the output, when funding is scarce – for the purpose of illustration – is shown in Figure 27 for both $dKE_{cap\_des_i}/dt$ and $dInv_{KEcap_i}/dt$. Note that the apparent mismatch between the desired additions of capacity and the allocated investment funds, where the green line for natural gas capacity expansion crosses the blue line for coal-fired expansion on the left-hand graph but remains below the blue line on the right-hand side, is a function of the different capital costs for the two technologies. In other words, the planned expansion of natural gas-fired plants is less expensive, in terms of capital, than the planned expansion of coal-fired plants. The difference in units therefore accounts for the different behaviours of the lines.

[62] The interest rate is added here to cover the costs of borrowing money for plant construction. I think this approach is suspect, because the money is borrowed for both the plant construction and operation periods – so this equation may require revision to include both τ_{kc} and τ_k.

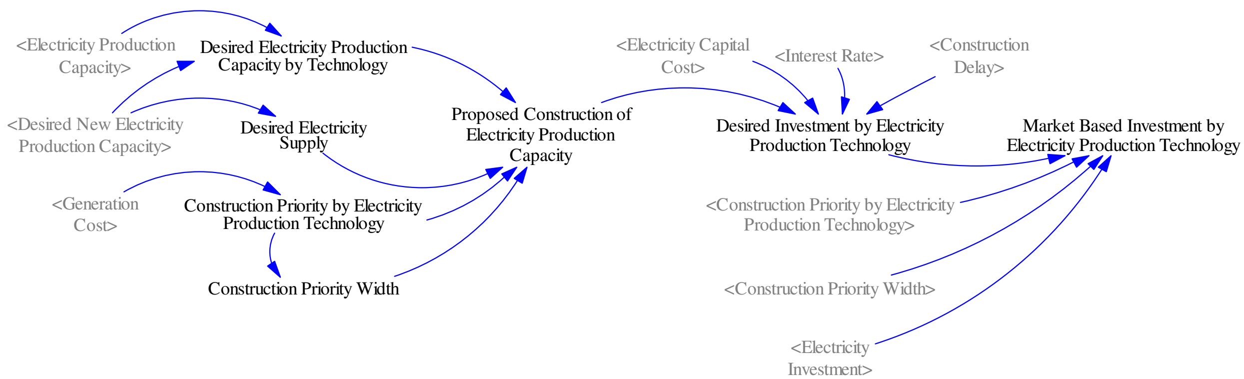

Figure 26: Basic calculation procedure for allocation of desired electricity production capacity to individual production technologies, and for the resulting desired investment by technology (in GW yr^{-1} and 10^{9} \$ yr^{-1})

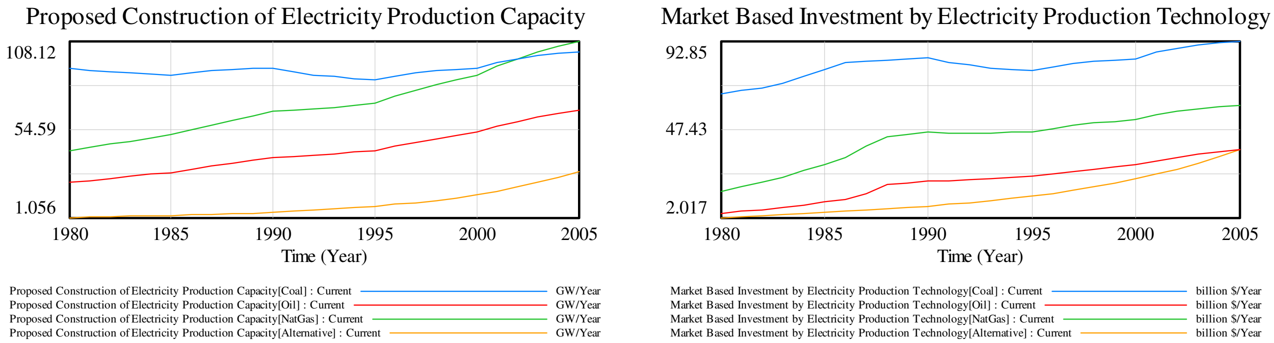

Figure 27: Preliminary results – for illustration purposes – of the *allocate by priority* calculations for construction and investment priorities (in GW yr^{-1} and 10^{9} \$ yr^{-1})

3.2.5 Policy-based Investment

Because of high capital costs, limitations on suitable locations, environmental concerns, and public disapproval, investment in nuclear- and hydro-electric production has generally been policy- rather than market-based. Indeed, Fiddaman (1997), de Vries et al. (1994) and the developers of several CGE-based models stated that such prescriptions were necessary in their models as well.

Specifically, nuclear capacity has not expanded greatly, as was anticipated in the 1970s, because of nuclear accidents at Three Mile Island and Chernobyl, which led to both increased regulation, and increased construction costs and times (Breeze, 2005). As of 2004, no new nuclear plants have been ordered in the US since 1978, and Asia is now the site of most nuclear capacity expansions, but is reason to believe that nuclear power is now increasing in popularity in the US once again (Breeze, 2005).

In the case of hydroelectric power, concerns largely centre on the environmental effects of large developments, which can disrupt wildlife habitat, displace populations, and upset downstream ecologies. However, when planned well, hydroelectric power is one of the cheapest electricity sources, and many sites for development remain, particularly in developing countries. Indeed, of roughly 8000

TWh yr^{-1} of technically exploitable hydro power in the world, only one-third (2650 TWh yr^{-1}) is currently used (Breeze, 2005).

3.2.5.1 Methodology for Nuclear and Hydroelectric Capacity Expansion Prescriptions

There are two ways to prescribe the two capacity expansions: through a difference-based "inventory correction" scheme, and through direct prescription of annual capacity additions. The first approach compares the current capacity with the historical capacity, and corrects for any discrepancies. It works to a degree, but the ten-year construction delay means that the actual capacity always lags the historical capacity – not ideal, since the aim is to prescribe a near-exact match to historical figures (otherwise, why *prescribe* values?). An approach similar to Fiddaman's (1997) $EP_{cap\_orders_i}$ (he calls this variable *EKO*) capital construction pipeline could potentially solve the problem, but would require much more work than is necessary. The second approach gives nearly-exact matches to the historical data, but requires annual capacity expansion data that are simply not available. Therefore, annual expansion data must be fabricated. Furthermore, these capacity expansions are subject to the same construction delays as in the first approach, which complicates their development, since the required investment must be calculated, and it occurs at the beginning of the construction period.

The fabrication of annual capacity expansion figures follows a *trial-and-error approach* that assigns yearly expansions, simulates the model, and checks the resulting correspondence with historical data. Without Vensim's "SyntheSim" feature, which automatically runs a simulation upon change in any model parameter and immediately presents the results, the procedure would have been a batch process: time-consuming and painful. With SyntheSim, the results of changes are presented nearly instantly, and the altered parameter remains selected for further modification.

The trial-and-error approach works as follows. Initial, *guess* values for annual nuclear and hydroelectric capacity expansions are listed in two *lookup tables*[63], one for each production technology. The lookup tables hold an assumed expansion value for each integer year from 1980-2005. Using SyntheSim, each expansion value is adjusted upwards or downwards to bring a closer match to the historical figures – both simulated and historical values are displayed in a graph that changes in real-time. In manipulating capacity expansions, there is only one limitation: any prescribed values must be non-negative.

The overall structure for determining nuclear and hydroelectric capacity expansions is given in Figure 28, while the corresponding investment is calculated according to,

$$\frac{dInv_{KEcap\_des_i}}{dt} = (1 + r_i)^{\tau_{kc}} \cdot KE_{cost_i} \cdot \frac{dKE_{cap_i}}{dt}$$

[63] A *lookup table* provides an output for a given input. It is analogous to an equation in the form y = f(x), but does not require specification of the function f(). In the capacity expansion case, the input will be the current time, *t*, in years, and the output will be the capacity expansion in that year, in GW. For example, when the input is 1985, the output might be 25 GW.

where the structure of the equation is the same as in section 3.2.4, except that the *desired* investment is the same as the *actual* investment in this case. The “prescribed nuclear and hydro capacity expansion” is a lookup table, as explained above, with its values given in Table 18, below. Note that the indices *i* refer here only to nuclear and hydroelectric power.

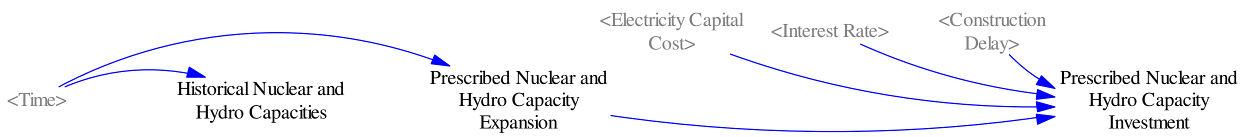

Figure 28: Basic calculation procedure for the prescription of electricity production capacity to nuclear and hydroelectric technologies, and for the resulting investment by technology (in GW yr^{-1} and 10^9 \$ yr^{-1})

3.2.5.2 Results of Nuclear and Hydroelectric Capacity Expansion Prescriptions

The *trial-and-error approach* is not ideal, since the correspondence between historical and simulated figures is judged visually, and since there are multiple solutions that give basically the same answer. However, the results are close enough for our purposes, and the approach is considerably faster than the alternatives. Note that the values will be sensitive to the model time-step, and so it may be necessary to generate new capacity expansion values if the model time-step changes.

Capacity expansions for nuclear and hydroelectric production are provided in Table 18, and their match to historical values, after passage through the construction pipeline, is shown in Figure 29.

Table 18: Prescribed annual capacity expansions for nuclear and hydroelectric power (in GW yr^{-1})

Time (Year)	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Nuclear	36	38	38	38	38	38	26	25	18	10	5	5	8
Hydro	95	90	28	15	5	4	6	22	22	24	24	24	28

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	12	14	18	18	18	24	24	24	24	24	24	26	26
	30	28	28	26	32	32	30	28	35	40	44	44	44

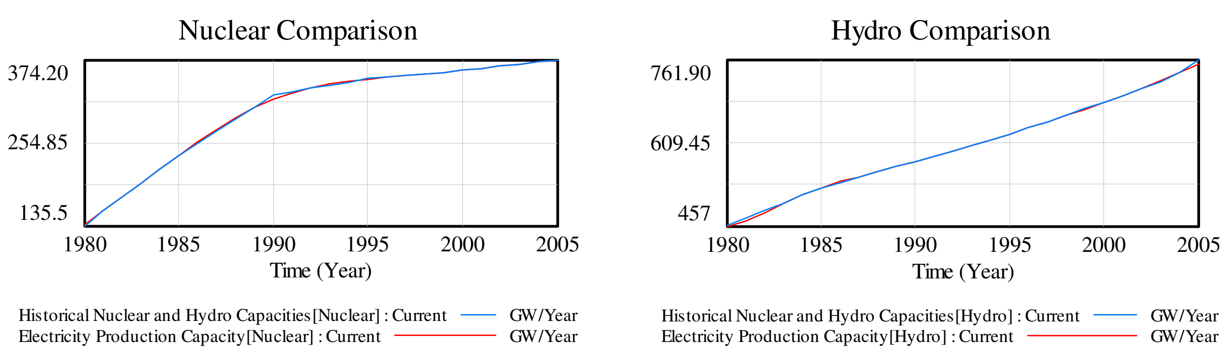

Figure 29: Historical *versus* simulated nuclear and hydroelectric production capacities (in GW yr^{-1})

The corresponding investment requirements are given in Figure 30 – note that these figures do not take into account any overruns in construction costs or project cancellations (which may have cost large sums in the wake of the nuclear disasters at Three Mile Island and Chernobyl). According to the figure, the total investment in nuclear capacity has increased from 1990 onwards, despite the lower expansions in capacity as compared with the early 1980s (see Table 18), because of increasing construction costs. As explained in section 1.2.3.3 and summarized in Table 13, nuclear construction costs have increased by a factor of ten, from \$250 kW^{-1} in the 1970s to roughly \$2250 kW^{-1} now.

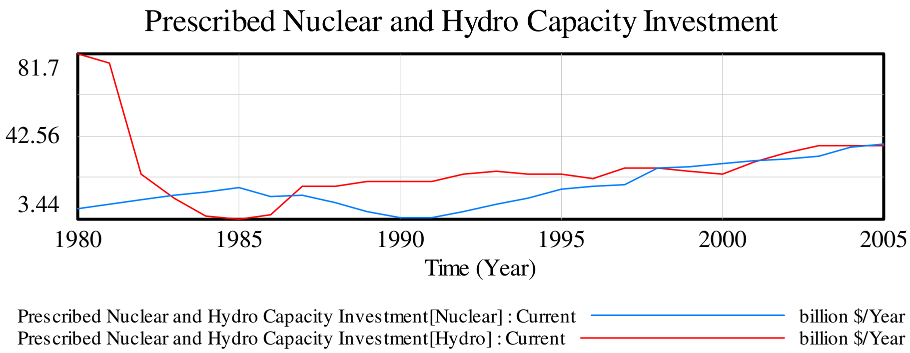

Figure 30: Required investment for prescribed nuclear and hydroelectric expansions (10^9 \$ yr^{-1})

3.2.6 Total Investment in Electricity Production Capacity

Summation of the market- and policy-based investments in electricity production technologies yields the total investment in electricity production capacity – the procedure is very straightforward, and was described first in section 3.2.2, along with its associated assumptions. In Vensim, the operation appears as in Figure 31.

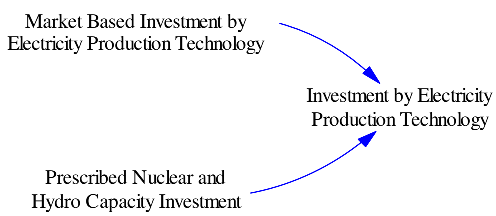

Figure 31: Basic calculation procedure for the total investment in electricity production capacity (in 10^9 \$ yr^{-1})

This total investment then flows into a *construction pipeline* with some similarities to Fiddaman's (1997) (see Appendix B, starting on page 159), which serves an important role in determining the maximum electricity production capacity (3.3.1), but mainly serves as a record of current invested funds in the electricity production sector. In other words, the **electric capital**, *as measured in billions of dollars*, has no functional role in model simulations – it exists for model validation purposes. Instead, calculation of the electricity production capacity is the important result of *investment*.

The construction pipeline, as measured in monetary units, is shown in Figure 32, and has similar characteristics to Figure 33.

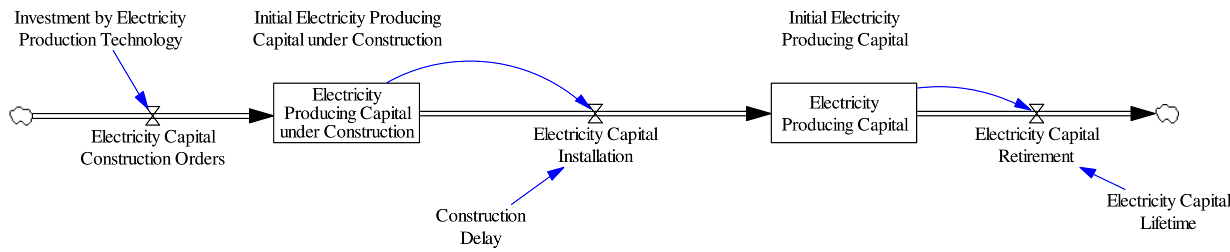

Figure 32: Basic calculation procedure for investment in electricity production capacity (in 10^9 \$ yr^{-1})

3.3 Electricity Production

Electricity production capacity is not all used – in fact, load factors for certain electricity production capital can be relatively low. The maximum production capacity (3.3.1) comes directly from investment, and its degree of utilization depends on variable costs (3.3.2).

The approach to determining capacity from the electricity investments of the previous section (3.2.6) is to use a *reverse approach* from the calculations in the Excel spreadsheet described in section 1.2.3, above. In other words, the maximum electricity production capacity depends on the capital investments and on a capital-capacity conversion cost (3.1.4): how many kW or GW of generating capacity can be produced for each dollar of existing capital, which is the opposite of the values listed in Table 13. In contrast to this approach, the other common approach uses a Cobb-Douglas or CES production function to determine energy production. This latter approach is used by Fiddaman (1997) and the CGE-based models; however, I think that, since our model already keeps track of investments into specific electricity-production technologies, and can therefore explicitly model the current production capacity by technology, the production function approach is less desirable.

Not all electricity capacity is used, and so capacity utilization becomes an important issue, particularly in terms of calculating greenhouse gas emissions – the purpose of modelling the energy production sector in the first place – since some installed capacity is GHG intensive, while other capacity is emissions-free. Capacity utilization, and thus electricity production by production-technology (in GJ yr^{-1} or TWh yr^{-1}), depends on *variable costs*, the sum of fuel and variable operation and maintenance costs (3.3.2).

3.3.1 Maximum Electricity-production Capacity

The *maximum electricity production capacity* plays a crucial role in the model, because it determines the maximum amount of electricity that can be produced in each year, regardless of demand.

The stocks and flows in Figure 33 represent both the maximum electricity-production capacity under construction (left) and the maximum operational capacity (right), as well as their rates of change – they are analogous to the energy production stocks described in section 2.2.2, above.

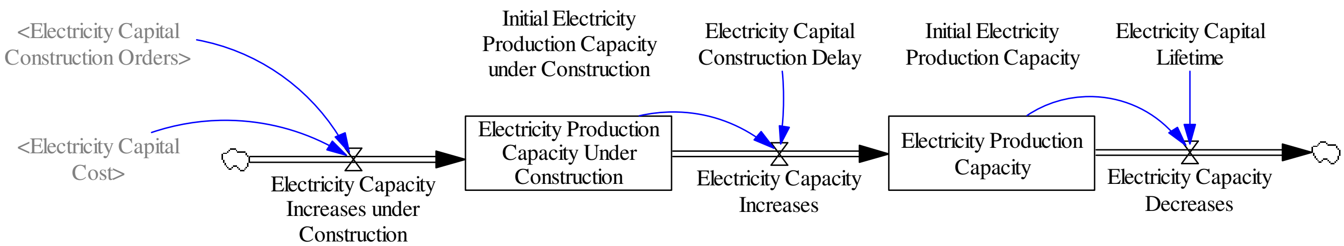

Figure 33: Basic calculation procedure for *electricity production capacity* (in GW)

The "electricity production capacity under construction" stock changes because of planned additional electricity-production capacity (in GW) and its completion, at which point it becomes operational and joins the "electricity production capacity" stock. Its equation uses the electricity capital costs (3.1.4) and investment in new production capacity (3.2.4, 3.2.5), and is given by,

$$KE_{cap\_orders_i} = \frac{dInv_{KEcap_i}}{dt} \Big/ KE_{cost_i}$$

where $KE_{cap\_orders_i}$ is the production capacity added to the construction pipeline (in GW yr^{-1}), $dInv_{KEcap_i}/dt$ is the amount of investment that technology *i* receives (in 10^9 \$ yr^{-1}), and KE_{cost_i} is the capital cost of production technology *i* (in \$ kW^{-1}; see section 3.1.4).

The total electricity production capacity under construction is given by,

$$KE_{cap\_constr_i}(t) = \int \left(KE_{cap\_orders_i} - KE_{cap\_install_i}\right) dt$$

where $KE_{cap\_constr_i}(t)$ is the left-hand stock in Figure 33 and represents the amount of electricity production currently under construction (in GW), while $KE_{cap\_install_i}$ is the electricity production capacity installed in the current period (in GW yr^{-1}).

The right-hand stock, "electricity production capacity", or KE_{cap_i}, changes through additions to the production capacity as construction is completed and through losses from the retirement of old production capacity. Its equation is,

$$KE_{cap_i}(t) = \int \left(KE_{cap\_install_i} - KE_{cap\_retire_i}\right) dt$$

A production capacity "pipeline" has been created here because electricity capital costs change over time. In fact, by the time the construction phase is over, the capital costs may have changed fairly considerably from their values at the beginning of construction. For example, for natural gas and alternative sources, the decrease in cost could be as much as \$80 kW^{-1} and \$250 kW^{-1}, respectively, while nuclear prices increase similarly instead. Thus, without the pipeline approach, the capacity expansion chosen would not match the capacity expansion actually installed.

3.3.2 Actual Electricity Production by Technology

While the previous section focuses on the modelling of maximum electricity production capacity, this section explains how actual production is determined. As explained in section 3.2, the *operational strategy* determines how much of the installed capacity is used and when, based on the *variable costs* (Hoogwijk, 2004); again, the approach is to use the *allocate by priority* algorithm (see subsection 3.2.3). The structure in Vensim that calculates actual electricity production on the basis of variable costs is shown in Figure 34.

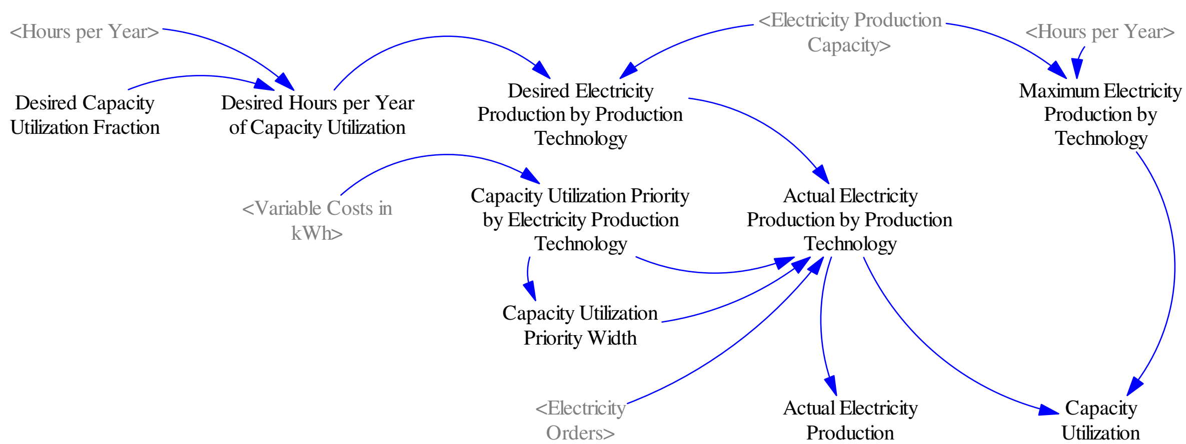

Figure 34: Basic calculation procedure for *electricity production* and *capacity utilization* (in GJ yr^{-1} and % yr^{-1})

Clearly, the actual energy orders play a critical role in determining electricity production, since it must match the orders. In the context of the *allocate by priority* function, these orders constitute the *supply* variable. Each of the electricity production technologies then vies to contribute its maximum to the electricity orders – as explained in subsection 3.2.4, each production lobby wants to produce its maximum output – which then constitute the *requests* component of the allocation function. The maximum (or *desired*) production is,

$$ElP_{max_i} = \kappa_{max_i} \cdot h/yr \cdot KE_{cap_i}$$

where ElP_{max_i} is the maximum electricity production (in GJ yr^{-1}), κ_{max_i} is the technology-specific maximum operating capacity, set to 90% for all production technologies except for both alternative and hydroelectric energy, which are set to 50% and 45% (perhaps an unreasonably low number)[64] because of weather- or ecologically-based restrictions on "fuel" availability, h/yr is the number of hours per year (24*365.25=8766), and KE_{cap_i} is the current technology-specific electricity production capacity (in GW). A conversion factor for GWh to GJ is necessary, and equals 3600 (1 GWh = 3600 GJ).

The priority of each request is determined on the basis of the variable costs per kWh of electricity production. Again, since higher priority values lead to higher allocations of the requested amounts,

[64] Although, the electricity generation capacity required to satisfy peak loads, plus some margin of safety (typically 20%) is significantly greater than average generation rates. Indeed, the *annual capacity utilization factor* has remained near 50-55% over most of the history of the electric utility industry (Naill, 1977: 89)

and since higher costs should lead to lower allocations, the inverse of the cost per kWh is used, such that

$$p_{prod_i} = 1/VC_{kWh_i}$$

where p_{prod_i} is the electricity production priority of request *i*, and VC_{kWh_i} is the variable cost of production for technology *i* (in \$ kWh^{-1}). The priority *width*, as explained in section 3.2.3, determines how much of the requested allocation is supplied, based on the differences in priority values. The two easiest approaches for *width* are to assign either the maximum priority value or the minimum priority value. The maximum priority approach would allocate electricity production most evenly across all generating capacity, while the minimum priority would allocate sequentially, from highest priority to lowest priority, so that some technologies would produce their maximum values, while others would produce no electricity at all, so long as the others could handle the electricity orders. The equations for both options, in logical and Vensim terminology for maximum and minimum widths, respectively, are,

$$w_{prod} = MAX\left(p_{prod_i}\right) \quad \text{or} \quad w_{prod} = VMAX\left(p_{prod}[i!]\right)$$
$$w_{prod} = MIN\left(p_{prod_i}\right) \quad \text{or} \quad w_{prod} = VMIN\left(p_{prod}[i!]\right)$$

There are reasonable grounds for either choice. Use of the maximum width approach would guarantee that all installed capital would see some operating time, and represent the dispersed nature of global electricity production capacity more realistically (many areas have only one production option, and so each area will use the technology it has). The minimum width approach would cause variable cost differences to play the driving role in allocation decisions, but may overemphasize small differences in variable costs.

The allocation equation then has this form,

$$ElP_i = ALLOCATE\ BY\ PRIORITY\left(ElP_{max_i}, p_{prod}, Hydro, w_{prod}, EO_{elec}\right)$$

where ElP_i is the electricity produced by technology *i* (in GJ yr^{-1}), and EO_{elec} is the total amount of electricity ordered in the current period, based on *historical data* (in GJ yr^{-1}).

Other Limitations

I am not sure what effect the omission of peak-load and base-load effects has on the selection of capacity utilization, and the allocation algorithm and *width* selection does not include factors such as regional resource availabilities, public aversion to certain technologies, or political preferences.

3.3.3 Market Shares for Electricity-producing Technologies

Market share values are important in determining average electricity prices. A simple calculation based on the Table 9 values yields market shares (Table 19) for each electricity production technology.

Alternative figures from 1971-2005 are available at a global level – and by individual countries and regions – in IEA (2007b), beginning at page II.265.

Table 19: Historical market shares for installed electricity-producing capital (%)

Fuel Type	1974	1980	1990	2000	2003
Coal	40.1	36.7	36.7	35.2	32.1
Oil	23.1	17.4	13.2	9.2	7.5
Natural Gas	13.1	15.1	15.4	22.5	28.7
Hydro	20.1	23.5	21.6	20.8	19.8
Nuclear	3.5	7.0	12.2	10.9	10.1
Alt E	0.1	0.3	0.8	1.3	1.8

To generate current market share values dynamically is straightforward. The form of the equation is simply,

$$\varsigma_i = \frac{KE_{cap_i}}{\sum_{\forall i} KE_{cap_i}}$$

where ς_i is the market share of electricity technology type *i* [Fractional], and KE_{cap_i} is the installed electricity capacity for technology *i*.

4. Preliminary Modelling Results: Energy Supply

The following tables and graphs illustrate the results of the system structures and equation forms described in the sections above – presenting the simulation results here allows a quicker reference to both model structure and results. The figures provided below are taken from a "base case" simulation run, and are generally compared with historical data, where available. I describe first the *primary energy supply* results (4.1) and then the *secondary energy supply* results (4.2). Note that the model structure and equations for the primary energy supply are described in section 2, while the secondary energy supply is described in section 3, above.

4.1 Primary Energy Supply

This section uses prescribed historical energy demand values for coal, oil, and natural gas (see Figure 15) to illustrate the results of the *energy extraction* modelling approach described above (2). The first set of results (4.1.1) deals with energy reserves and their changes over time through extractive activities (2.2.1), while the second set of results (4.1.2) deals with the installed extractive capacity (2.2.2.1). The final set of results (4.1.3) demonstrates the effects of the market price equations (2.2.2.2) and their correspondence to historical price variations.

4.1.1 Simulated Energy Reserves and Primary Energy Production

Fossil fuels are non-renewable resources: once depleted, they are no longer available for human use. The model tracks current resource stocks, and simulates changes in coal, oil, and natural gas reserves over time as a result of discoveries of new resource stocks, and depletions of known reserve stocks. Simulated changes over time in the *energy reserve* (2.2.1) values for the three fuels are shown in Figure 35.[65] In 2005, coal reserves are simulated as 905 775 Mt, while actual figures[66] are 905 141 Mt; for oil, the difference is 1281 BB *versus* 1277 BB, and for natural gas, 171.9 Tm^3 *versus* 171.2 Tm^3.

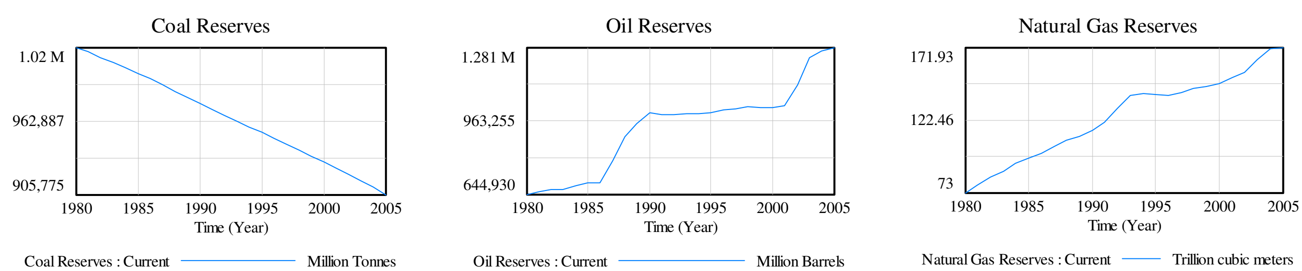

Figure 35: Simulated energy reserve values for coal, oil, and natural gas

[65] Their close correspondence with historical values is expected in the case of heat-energy production but not necessarily in the case of electric-energy production, since electricity production by fuel is simulated based on market prices as opposed to prescribed values (3.3). For electricity production, the freer simulation of coal, oil, and natural gas demand applies to roughly 35-55% of coal demand, where demand for coal for electricity production rises from 1980-2005 with a maximum in 2000-2002, to 9.5-11% of oil demand, and to 17.5-31% of natural gas demand, where the electricity-based natural gas demand is relatively flat through the 1980s but rises thereafter to 2005.

[66] See the "Energy Reserves" MS Excel database.

Figure 36 shows the energy resource extraction values for the three fuels that correspond to the simulated reserve values in Figure 35. Historical values are used for reserve discoveries.[66]

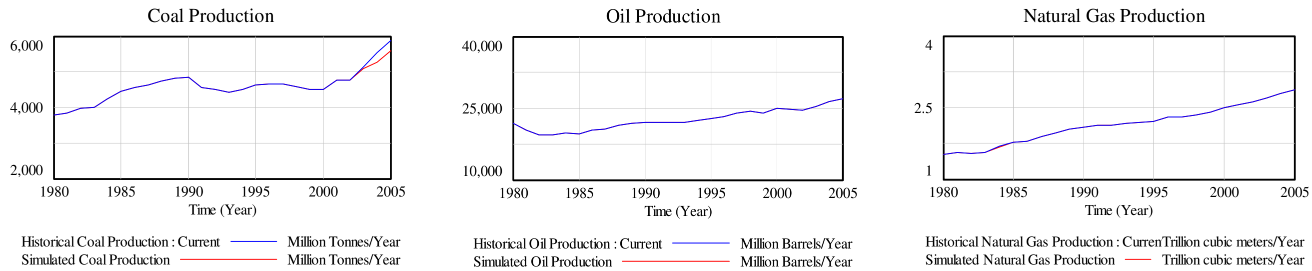

Figure 36: Simulated energy extraction values for coal, oil, and natural gas

4.1.2 Primary Energy Extraction Capacity and Comparison with Demand

Identified fossil fuel reserves are extractable through mining and pumping. The installed *extraction capacity* determines the upper limit of reserves that can actually be extracted for human use each year. Simulated maximum resource extraction capacities for the three fossil fuels are displayed in Figure 37, where the left-hand side shows the maximum extraction capacity, and the right-hand side shows both demand and extraction capacity.

For all three fuels, the production capacity is clearly more stable than the demand. In the cases of oil and natural gas, production capacity is always sufficient to ensure that all demand is met, but coal production falls below demand in the early 21st century when coal demand begins to rise rapidly after more than a decade of decline. Note that global extraction *capacity* figures are not available, but that *production* values are available from a variety of sources.

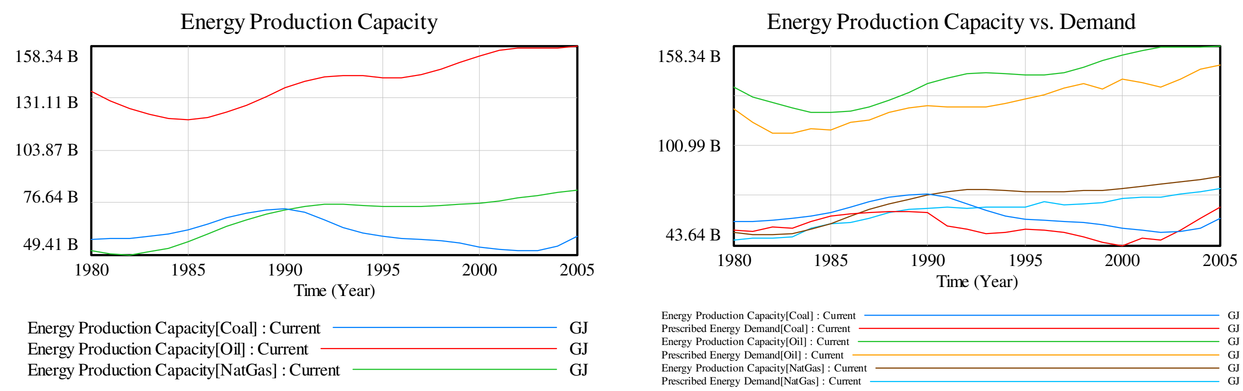

Figure 37: Simulated energy extraction capacity for fossil fuels and capacity *vs.* demand (GJ)

4.1.3 Production Costs and Market Prices of Primary Fuels

Investment in new extractive capacity (2.2.2.2) depends on its profitability, which depends in turn on the difference between market prices for energy resources and their production costs, and on the amounts of resources extracted. Figure 38 shows the variation in simulated market prices for coal, oil, and natural gas as compared with the relatively stable (less volatile) production costs.

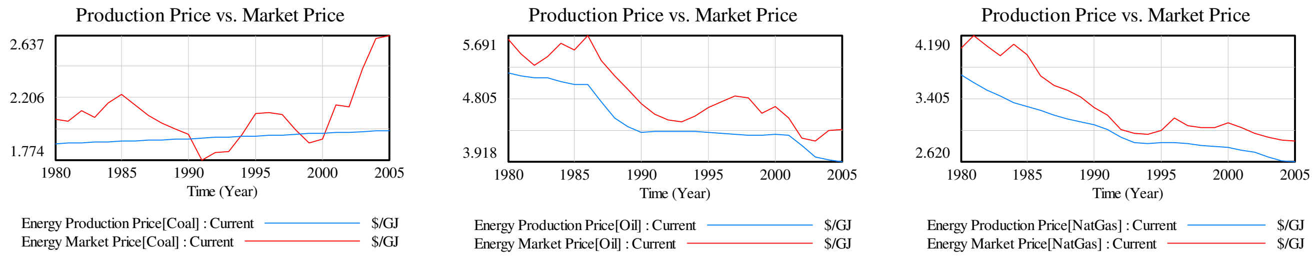

Figure 38: Simulated fossil fuel production costs and market prices (in \$ GJ^{-1})

Unfortunately, these price values are also difficult to compare with historical values because of their variability between producing and consuming nations. However, some figures are available. Import and export prices for coal for several world regions are shown in Figure 39; indices of end-use energy prices are shown in Figure 40; and US domestic fossil fuel production costs are shown in Figure 41. In terms of more general values, according to IEA (2008b),

- Table 27: crude oil import prices have generally tripled to quadrupled from 1997-2007;
- Table 30: the rise in gasoline prices has been slower, with only a doubling of prices over that period;
- Tables 32 and 33: fuel oil prices have tripled on average from 1997-2007.

Further, IEA (2007e) data show that,

- Tables 8-15: natural gas import prices in Europe have tripled, on average, since 1999, more than doubled in Japan's case, and more than tripled in the case of the USA.
- Table 16: Natural gas prices for industry have roughly doubled from 1995-2006 – although the change in each country can differ strongly from the average – while the change in prices charged to households is more extreme in most cases.

The mismatches between simulated and actual oil and natural gas prices may result from the strong decreases in production costs simulated for both fuels, which relate only to actual fuel reserve volumes, but not to their accessibility or their individual reservoir sizes.

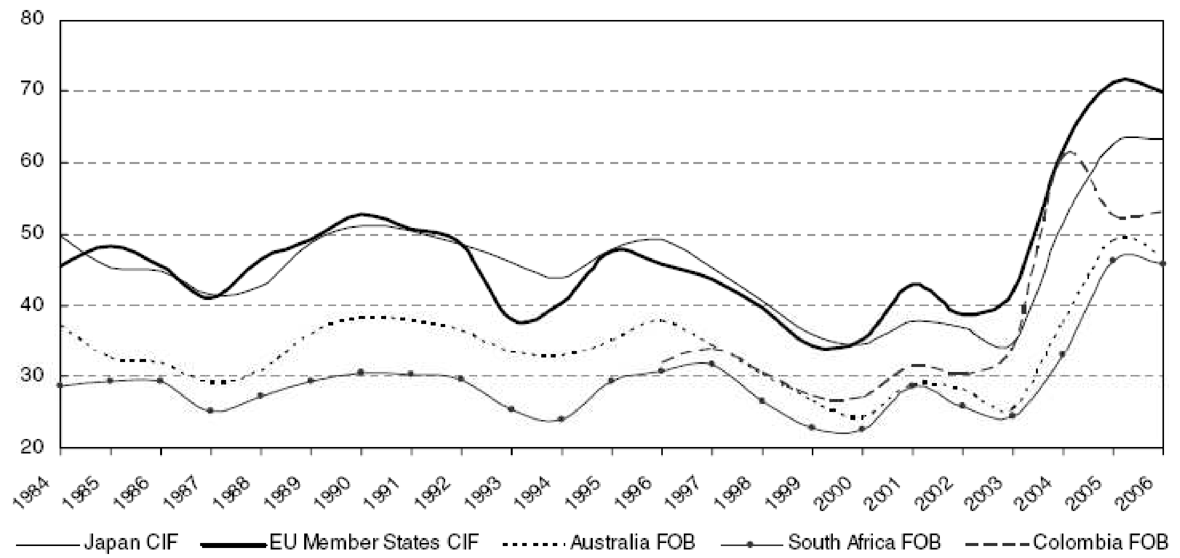

Figure 39: Steam coal import and export value comparison (in US \$ t^{-1}), from Figure 2 of IEA (2007a)

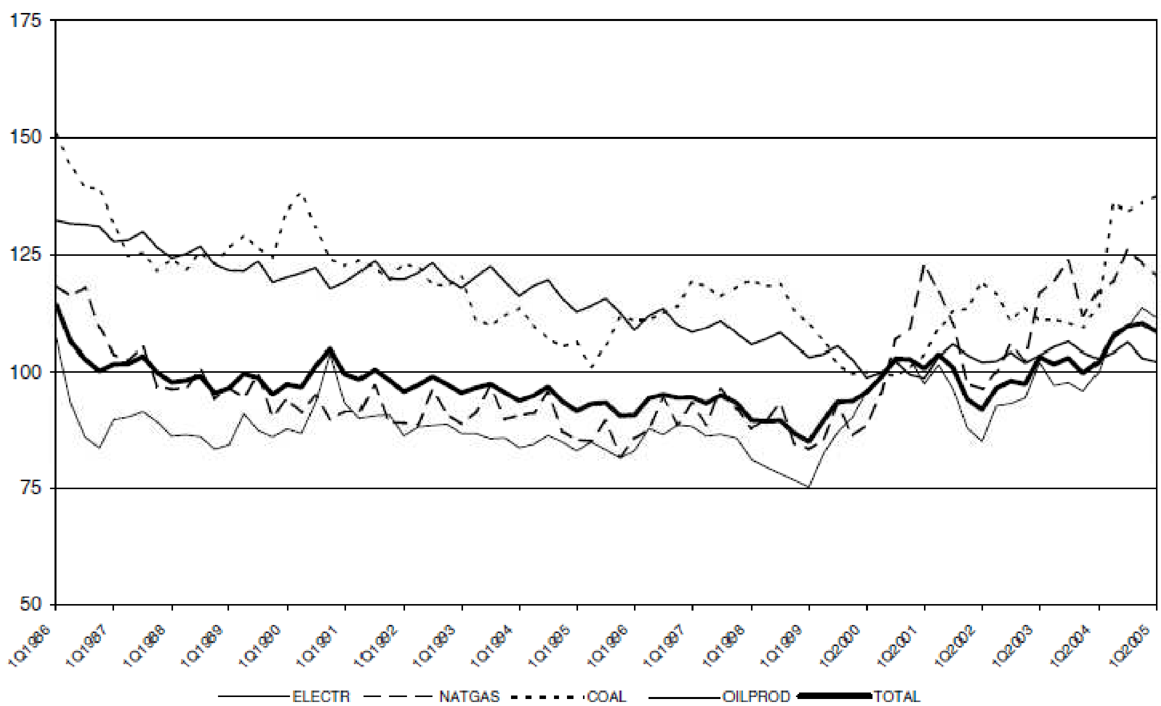

Figure 40: Indices of real energy end-use prices, from IEA (2005: I.81)

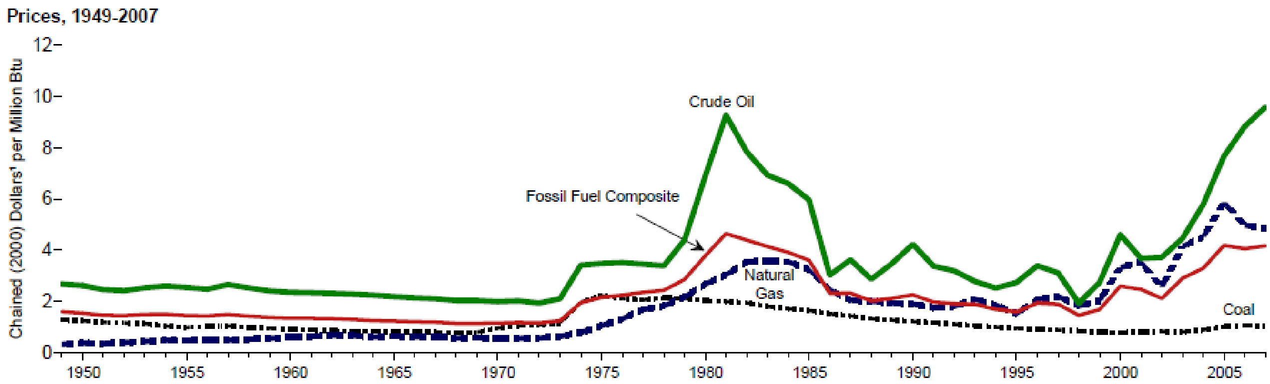

Figure 41: US fossil fuel production costs (in chained 2000 \$ MBtu^{-1}), from Figure 3.1 of EIA AER (2008a)

4.2 Secondary Energy Supply

This section illustrates the results of the structural and mathematical representation of *electricity production* described above (3). The first set of results (4.2.1) pertains to the simulated *maximum electricity production capacity* and its change over time (3.3.1), while the second set of results (4.2.2) deals with actual electricity production and shows the effects of differences in the *width* variable of the *allocate by priority* algorithm (3.3.2). The final set of results (4.2.3) shows the simulated market shares of each electricity production technology for comparison with historical market share values (3.3.3).

4.2.1 Electricity Production Capacity

General results of the *maximum electricity production capacity* calculation approach, which uses the *allocate by priority* algorithm and prescribed changes in *electricity orders*, are illustrated in Figure 42. The simulated values are also compared quantitatively with historical values in Table 20 – note that the historical values were presented first in Table 1, above.

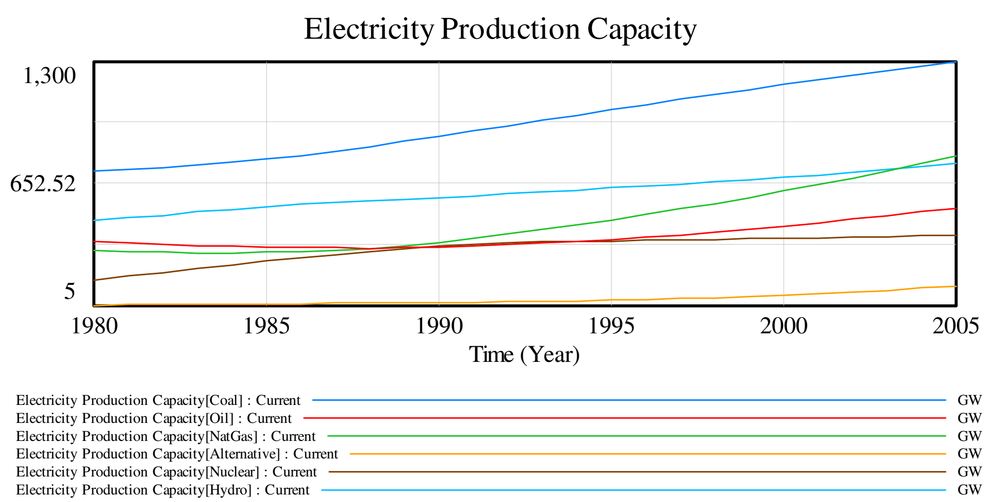

Figure 42: Preliminary results – for illustration purposes – of increases in electricity production capacity by production-technology (in GW)

Table 20: Comparison of historical *versus* simulated electricity production capacities by technology (in GW)[1]

Year	1980	1985	1990	1995	2000	2001	2002	2003	2004	2005
Global Cap. (**D**)	1945.6	2315.4	2658.3	2929.3	3279.3	3392.3	3512.3	3638.9	3748.4	3872.0
Global Cap. (**S**)	1946.0	2147.4	2456.8	2853.2	3304.4	3403.9	3507.4	3616.1	3730.2	3850.1
Thermal Cap. (**D**)	1347.8	1542.5	1737.6	1929.6	2195.5	2285.9	2387.6	2485.8	2569.9	2652.3
Thermal Cap. (**S**)	1348.0	1374.1	1546.9	1850.2	2205.9	2282.8	2362.2	2444.3	2529.4	2617.1
Coal Cap. (S)	*715.0*	*777.6*	*899.1*	*1041.9*	*1173.5*	*1198.8*	*1223.9*	*1249.2*	*1274.6*	*1300.1*
Oil Cap. (S)	*339.0*	*312.9*	*311.1*	*352.9*	*423.3*	*440.5*	*458.9*	*478.5*	*499.3*	*521.3*
N. Gas Cap. (S)	*294.0*	*283.5*	*336.6*	*455.4*	*609.1*	*643.6*	*679.4*	*716.7*	*755.4*	*795.7*
Hydro Cap. (**D**)	457.2	527.2	575.4	625.0	683.3	695.9	706.8	720.3	739.0	761.9
Hydro Cap. (**S**)	457.0	526.6	575.1	625.4	683.3	695.6	708.5	722.2	737.1	753.1
Nuclear Cap. (**D**)	135.5	236.8	323.1	346.9	358.3	361.4	361.6	368.5	368.2	374.2
Nuclear Cap. (**S**)	136.0	236.2	316.9	346.3	358.6	361.4	364.4	367.4	370.6	374.1
Alt. E. Cap. (**D**)	5.0	8.9	22.1	27.8	42.3	49.1	56.3	64.3	71.2	83.6
Alt. E. Cap. (**S**)	5.0	10.4	17.9	31.4	56.6	64.0	72.4	82.1	93.1	105.8

[1] In the table, **D** stands for figures from the data, while **S** stands for simulated values

4.2.2 Electricity Production

Actual electricity production depends both on the maximum capacity (3.3.1), which sets an upper limit to production, and on economic factors – as modelled through the *allocate by priority* algorithm (3.3.2) – which determine actual capacity usage (0 < *capacity usage* < max). This section illustrates the effects of the choice of *width* values in the algorithm, and compares the simulated electricity production capacity usages by technology with the historical figures.

General effects of the choice of *maximum* or *minimum width* are illustrated in Figure 43.

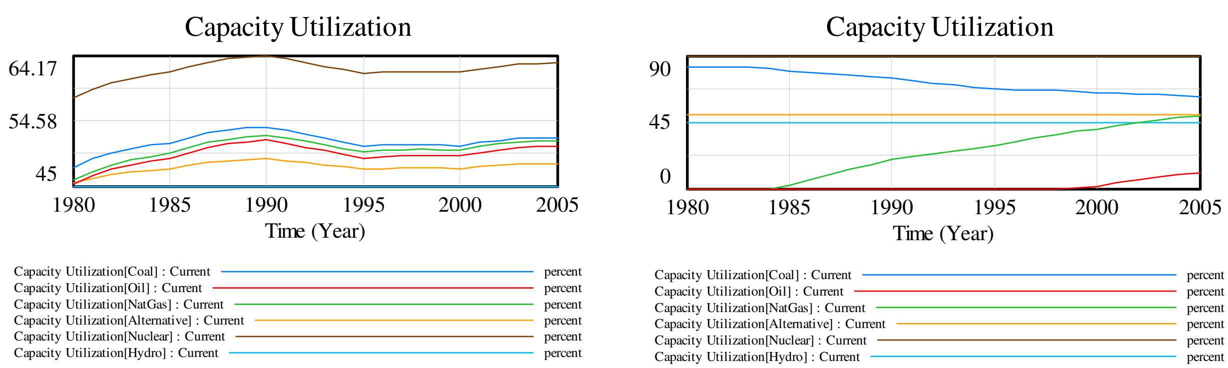

Figure 43: Preliminary results – for illustration purposes – of the behavioural effects of *maximum* versus *minimum width* calculations on capacity utilization (in % yr^{-1})

In viewing Figure 43, recall that alternative sources and hydroelectricity are limited to 50% and 45% capacity utilization, respectively (3.3.2). Furthermore, use of the minimum width (right-hand side) clearly results in unrealistic behaviour: neither oil-fired nor natural gas-fired plants are used early (natural gas), or even relatively late (oil), in the simulation period. The maximum width approach (left-hand side) allocates the capacity utilization much more evenly. Hydroelectric production always occurs at its maximum, while nuclear production tends to be considerably higher than the other capacity utilizations, since both have very low/zero fuel costs compared with thermal sources.

The overall performance of this simulation approach is compared quantitatively with historical values in Table 21 – note that the historical values were presented first in Table 5, above.

Table 21: Comparison of historical versus simulated electricity production by technology (in TWh yr^{-1})[1]

Year	1980	1985	1990	1995	2000	2001	2002	2003	2004	2005
Global Cap. (**D**)	8026.9	9477.1	11323	12625	14619	14825	15376	15918	16650	17351
Global Cap. (**S**)	8030.0	9477.0	11320	12625	14620	15166	15712	16258	16804	17350
Thermal Cap. (**D**)	5588.5	6041.1	7137.9	7785.1	9281.3	9504.3	9949.6	10476	10935	11455
Thermal Cap. (**S**)	5517.0	6080.0	7192.0	8160.7	9750.0	10185	10615	11040	11456	11865
Coal Cap. (S)	*2992.5*	*3497.2*	*4231.8*	*4645.2*	*5233.4*	*5393.8*	*5544.7*	*5685.4*	*5815.6*	*5935.2*
Oil Cap. (S)	*1343.4*	*1345.6*	*1410.8*	*1520.2*	*1832.6*	*1926.5*	*2022.8*	*2121.0*	*2220.9*	*2322.0*
N. Gas Cap. (S)	*1181.0*	*1237.2*	*1549.4*	*1995.4*	*2684.0*	*2864.3*	*3047.6*	*3233.1*	*3420.0*	*3607.4*
Hydro Cap. (**D**)	1722.9	1954.9	2148.9	2457.3	2645.4	2550.7	2596.8	2616.0	2759.2	2900.0
Hydro Cap. (**S**)	1802.7	2077.4	2268.6	2466.8	2695.5	2744.1	2794.7	2848.9	2907.7	2970.8
Nuclear Cap. (**D**)	684.4	1425.4	1908.8	2210.0	2449.9	2516.7	2545.3	2517.8	2615.0	2625.6
Nuclear Cap. (**S**)	690.3	1276.1	1782.5	1866.9	1938.4	1968.9	1997.2	2022.8	2045.7	2066.5
Alt. E. Cap. (**D**)	31.1	55.5	127.1	172.2	242.6	253.0	284.5	308.2	341.5	369.7
Alt. E. Cap. (**S**)	19.9	43.5	76.9	130.5	236.2	268.4	305.1	346.7	394.2	448.1

[1] In the table, **D** stands for figures from the data, while **S** stands for simulated values

4.2.3 Market Shares

Finally, market share values are important in determining average electricity prices. The calculation of market share values described in section 3.3.3 yields the market share values in Table 22 – compare with the values in Table 19.

Table 22: Simulated market shares for installed electricity-producing capital (%)

Fuel Type	1974	1980	1990	2000	2003
Coal	N/A	36.7	36.6	35.5	34.5
Oil	N/A	17.4	12.7	12.8	13.2
Natural Gas	N/A	15.1	13.7	18.4	19.8
Hydro	N/A	23.5	23.4	20.7	20.0
Nuclear	N/A	7.0	12.9	10.9	10.2
Alt E	N/A	0.3	0.7	1.7	2.3

The simulated values for hydroelectric and nuclear market shares are prescribed, and so the close correspondence between the values in Table 19 and Table 22 is expected. The match between coal-fired production and alternative sources is also good, but the natural gas-fired capacity is too low, while the oil-fired capacity is too high. The reasons for differences between historical and simulated oil-fired and natural gas-fired capacity are not clear, but could have several roots. From a simulation perspective, the cause may be the choice of the *width* value in the *allocate by priority* algorithm used in part (c) of section 3.2.4. However, I suspect the problem lies in the calculation of fuel costs, which show none of the volatility that might otherwise dissuade investment in oil-fired production, and in the omission of *expectations*, since oil prices are unlikely to remain at their relatively low current values as oil reserves disappear.

Chapter Three: Energy Demand

This chapter describes the energy demand component of the model and its related economic variables. It begins with a review of basic principles that play an important role in energy demand modelling, and of the drivers that change energy demand over time, and then focuses on the COAL2 model, whose representation of energy demand is used here (1). The actual approach toward modelling the quantity of energy demanded by the economy is then described and explained (0), including the net energy demand, and specific heat-energy and electric-energy demands. The chapter concludes with a set of preliminary model results (3).

1. Key Principles in Modelling Energy Demand

Energy demand is basically a product of the economic sector. Capital stocks in the economic sector require energy, which is broken into two categories in most models[67]: heat (i.e. manufacturing, space heating, transport) and electricity. In general terms, the relative costs of heat-energy versus electric-energy determine the mix of sources used in future production, as well as overall energy use. Thus, for the first point, if coal becomes more expensive, investment into natural gas/alternatives will eventually lower the aggregate price as coal becomes less-commonly used. And for the second point, rising energy prices should have long-term effects on energy use by encouraging energy conservation and instigating improvements to capital efficiency.

Beyond the heat-electricity characterization, further division by use is possible. Each of the energy demand sectors – industrial, residential, commercial, transportation, and other (see Chapter 2, section 1.2.1) – has different electric and non-electric energy requirements, which are changeable over time (to some degree). Although this division of energy requirements is not absolutely necessary, it makes sense especially when energy-use sectors are basically one-fuel-only and substitution is either unlikely or even impossible – for example, transportation uses oil almost exclusively, for example, and any short-term movement away from oil is highly unlikely.

The most important decision about modelling energy demand relates to the inclusion of *short-term* changes in demand. After all, demand is not just a function of income and price trends over the long term, but also depends on short term variations in both. Short-term effects are more difficult to model, because the ability to model short-term changes in demand – through substitutions and demand fluctuations linked to rapid changes in energy prices, for example – necessitates an optimization approach. In an optimization framework, the model solves for the values of supply and demand that produce equilibrium: the amount of energy supplied at a particular price equals the energy demand at that price, at which point the energy market clears. Sellers have no more energy to sell, and buyers have all the energy supply they desire. Low prices will see more demand, and high prices will see less.

[67] Such models include TIME(R) (de Vries and Janssen, 1997; de Vries et al., 1994) and the CGE-based models (EPPA, SGM, GTEM, and MERGE). In addition to disaggregation of electricity production, some CGE models also subdivide a variety of heat-energy requiring industries by production technologies – this approach is most evident in the representation of steel production in SGM, for example.

Of course, regardless of the optimal price, its level will have longer-term implications for energy demands, with relatively low prices encouraging greater energy use, and high prices encouraging greater efficiency – and possibly restricting economic growth.

1.1 Drivers of Energy Demand

The drivers of energy demand are similar in most models. The simplest is a *per capita energy demand* value based on historical and current population and energy use, where any changes in demand are a function of population change, energy prices, and technological change. TARGETS (de Vries and Janssen, 1997) uses this sort of general approach, where per capita economic activity and population serve as the drivers for the energy sector.[68] A second, *embodiment of energy requirements* approach is used in FREE (Fiddaman, 1997), where capital stocks, as an aggregate, require specific amounts of energy for production.[69] According to Fiddaman (1997: 80),

> Embodiment of energy requirements in capital allows one to distinguish between the costs of suboptimal capital utilization during a transition to a different energy system and the true long-run costs of that system. It also allows the long-run elasticity of substitution among energy supply technologies to be realistically high, without generating unrealistic short-term behaviour, because the substitution induced by price changes takes effect only gradually, as the capital stock is replaced.

An important note as regards modification to the long-term-only representation of energy demand in the current model is that FREE incorporates both short-run and long-run production functions in a simulation framework.[70] In other words, it may be possible to represent short-term changes in demand in the model without adopting an optimization approach – see Fiddaman (1997: 84).

Of course, TIME(R) and FREE model energy demand/use in much less detail than do the CGE-based models, which include the manufacture of specific products, international trade, and so on. Specifically, EPPA (Paltsev et al., 2005) includes a variety of variables that affect energy demand and production: 1) the rate of capital accumulation, 2) population and labour force growth, 3) changes in productivity of labour and energy, 4) structural changes in consumption, 5) fossil fuel depletion, and 6) the availability of backstop technologies. SGM (Edmonds et al., 2004) likely takes a similar approach, since it, like EPPA, is an economic (CGE) model interested in the exchange of factors of production for

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[68] I am inclined to use a different approach, however, because our model includes the economic sector explicitly, so that capital energy requirements can actually be represented, and so that installed and planned capital stock, rather than population, determines current and future energy requirements.

[69] The basic energy requirements equation is $ER_i(t) = \int (N_i(t) \cdot [I(t) + \varepsilon \cdot K(t)] - (\delta + \varepsilon)ER_i(t))dt$, where ER_i is the energy requirement, N_i is the planned energy intensity of new capital, I is the investment rate, K is the capital for goods production, ε is the fractional retrofit rate, and δ is the fractional discard rate. The total intensity of capital, N_T, is $N_T = \sum_i {ER_i}/{K}$.

[70] Use of the term "simulation" in this context represents a *system dynamics* approach toward mathematical modelling of the system in question. *Simulation* is distinct from *optimization*. Whereas the aim of optimization is to find a "best value" for a decision variable based on an objective function and a set of constraints, simulation focuses on describing a system structure through equations, observing its behaviour over time through simulation, and then analyzing the results to understand the causes of that behaviour. Simulation models have few to zero constraints. Essentially, the goal of optimization is to find a best value, while the goal of simulation is to understand patterns of behaviour and to identify systemic sensitivities.

goods and services. In terms of production in SGM, relative prices in each sector determine the mix of inputs.

With the exception of points 4 and 6, EPPA does not introduce substantially new variables. For example, FREE also includes capital accumulation (more capital means more energy required), population growth (more population means more consumption), productivity effects (technological change), and fossil fuel depletion. Instead, the level of detail, rather than behavioural drivers, sets the models apart. EPPA includes capital vintaging and "malleable" versus "rigid" capital, for example. SGM contains 21 production sectors, each of which produces a unique good through either CES of Leontief production functions.

Manne et al. (1995) are not explicit about the nature of energy demands in the MERGE model; however, since the model is an applied general equilibrium (CGE) model, it most likely uses input-output tables – like the GTAP tables used by other CGEs, and most obviously GTEM – to convert energy resources to intermediate goods, and intermediate goods to final output. If this interpretation is correct, then relative prices[71], in combination with substitution factors, will determine energy demand in CGEs. Bahn et al. (2006) support this conclusion:

> The energy module [of MERGE] is a bottom-up process model. It describes the energy supply sector of each region, in particular the generation of electricity and the production of non-electric energy. It captures price-dependent substitutions of energy forms and energy technologies to comply with greenhouse gas (GHG) emission abatements. The macroeconomic module is a top-down macroeconomic growth model. It balances the rest of the economy of a given region using a nested constant elasticity of substitution production function. It captures macroeconomic feedbacks between the energy system and the rest of the economy, [such as the] impacts of higher energy prices on economic activities.

The MiniCAM model (Kim et al., 2006) is a well-known integrated assessment model designed to investigate policies related to energy production, transformation, and use, through a modelling approach that captures elements of both "bottom-up" with a "top-down" frameworks.[72] According to Smith and Edmonds (2006: 587), MiniCAM "provides an internally consistent, equilibrium analysis of technologies within the global system. General equilibrium effects and connections, however, are not modelled; [instead], the allocation of capital and labour across production processes are assumed to

[71] Manne et al. (1995: 19) explain that, at each point in time, MERGE equilibrates supplies and demands "through the prices of the internationally traded commodities: oil, gas, coal, carbon emissions rights, and a numeraire good. This numeraire represents a composite of all items produced outside the energy sector."

[72] Two broad approaches exist for modeling the interactions between energy, economic, and environmental systems and technology. The ***bottom-up approach*** depicts a rich set of representative energy-using technologies at a level of detail such that engineering studies can be used to cost out a representative example (e.g. a 500 MW coal-fired power plant)… These models can be used to identify, for example, the least-cost mix of technologies for meeting a given final energy demand under GHG emissions constraints. They often take energy and other prices as exogenous. ***Top-down models*** typically represent technology using relatively aggregated production functions for each sector of the economy. For example, electricity production may be treated as a single sector with capital, labour, material, and fuel inputs… The particular focus of the top-down approach is market and economy-wide feedbacks and interactions, often sacrificing the technological richness of the bottom-up approach [entire passage taken from Pg. 686 of McFarland et al. (2004)].

occur within the context of larger long-term economic equilibrium." Economic processes in the model occur in its "marketplace object":

> The Marketplace object contains individual Market objects that represent the transactions of a single good and contain information on the characteristics of the good, trading regions, and market price, supply, and demand for the good. We represent the amount of goods available for sale at a given set of prices as the quantity supplied, and that requested for purchase at that same set of prices as the quantity demanded (Kim et al., 2006: 71).

1.2 An Alternative: The COAL2 Energy Demand Sector

The energy demand modelling approaches described above are relatively, and in some cases extremely, complicated. The current model version therefore uses a much simpler, long-term energy demand model, based on the COAL2 energy demand sector (Naill, 1977). As in COAL2, rather than modelling energy *demand*, we model the *energy quantity demanded*, which avoids the necessity for short-term price optimization. Of course, the omission of short-term effects has implications for model behaviour that are discussed later in this document – see the *model limitations* section below. The current representation of energy demand in our model is intended basically as a place-holder, until a more detailed version is available. Since we use a modification of the COAL2 demand sector, a description of its structure and basic assumptions is provided below. Note that Appendix D (page 169) lists the DYNAMO code for energy demand in COAL2 and its interpretation, while section 2.1.2 of Chapter Two describes the basic causal structure and energy supply components of COAL2.

COAL2's demand sector differentiates between three energy products: coal, electricity, and oil/gas. “Its purpose is to simulate long-term changes in the amount of, and preferences among the three products in response to GDP and price changes” (Naill, 1977: 23). Once the net demands for each of the three energy sources are determined, the individual energy supply sectors allocate labour, capital, and resources to meet the consumer demands.

COAL2 includes several important assumptions:

- The relative *inconvenience* of coal as a direct fuel has decreased its share of the final energy market in the past; COAL2 represents this shift as an income effect: as income rises, consumers can afford the more convenient forms of fuel;
- Changes in the price of electricity and rising incomes account for the increasing fraction of net energy demanded as electricity;
- Long-term trends away from coal and towards electricity and oil & gas are consistent across the energy consuming sectors (industry, transportation, residential and commercial), and so no new insights would be gained by disaggregating energy demand among energy-consuming groups (pg. 24 shows the figures to support this decision)

The causal structure used to determine changes in demand is illustrated in Figure 44. *Net energy demand* is the key variable here. It represents the total energy consumption in the economy, and is distinct from the gross energy demand, which is larger because energy production is not 100% efficient. Clearly, the net energy demand is determined by GNP and by the average energy price, where GNP is exogenous to the model, and the price is calculated as a weighting of oil & gas, electricity, and coal prices with their usage rates. These prices are calculated in the energy production sectors and are endogenous. Clearly, *net energy demand* is influenced by an *income effect* and by a *price effect*.

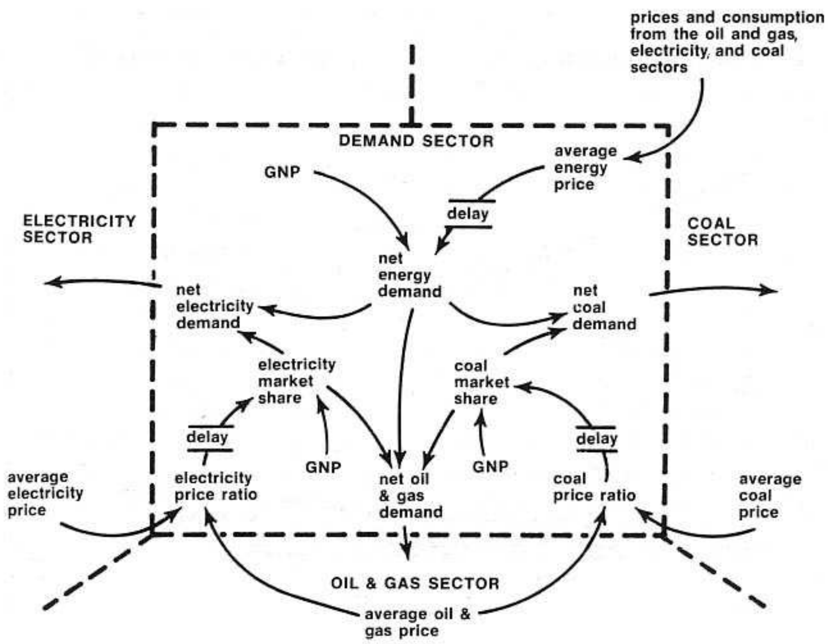


Figure 44: Demand sector causal diagram, from Figure 3-12 of Naill (1977)

As Figure 45 shows, the responsiveness of energy demand to a change in price is determined by two *elasticities*, which represent the percentage change in demand caused by a 1% change in each driving variable. The income effect has an elasticity of one, and the price effect has an elasticity of -0.28: a 1% increase in GNP causes a 1% rise in net energy demand, while a 1% rise in price causes a -0.28% rise in demand. The *delay* (10 years) represents the time taken to perceive and act upon a price change by conserving energy, or by refitting or replacing equipment with new, energy-conserving equipment.

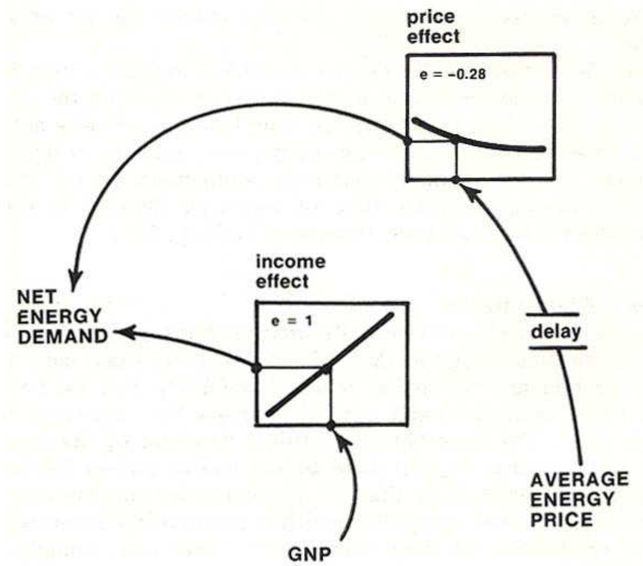


Figure 45: Net energy demand mechanism, from Figure 3-9 of Naill (1977)

The interfuel competition structure of COAL2's demand sector is summarized next, but our model uses a different approach, described below, for calculating changes in the fuel mix. Interfuel substitution is designed to explain why coal use dropped dramatically from 1950-1975 in the US, while both electricity and oil & gas increased their market shares, as well as to project the future mix of energy demand. Figure 46 and Figure 47 illustrate COAL2's assumptions.

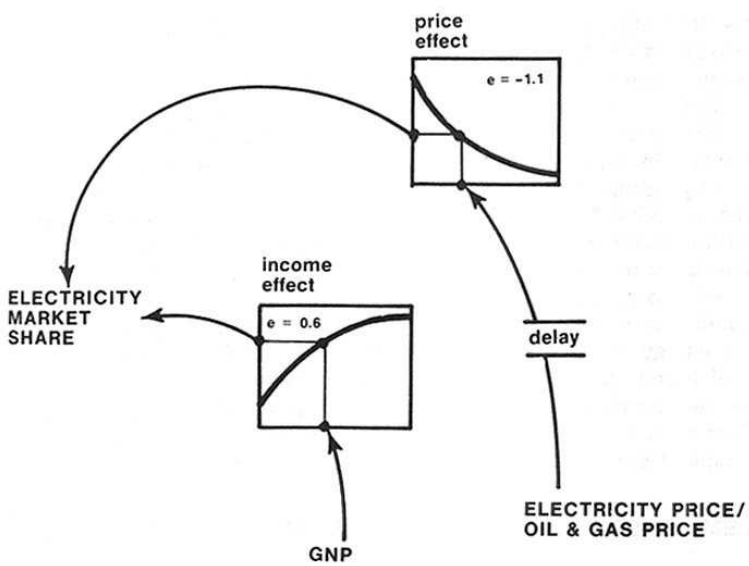


Figure 46: Electricity's share-of-demand mechanism, from Figure 3-10 of Naill (1977)

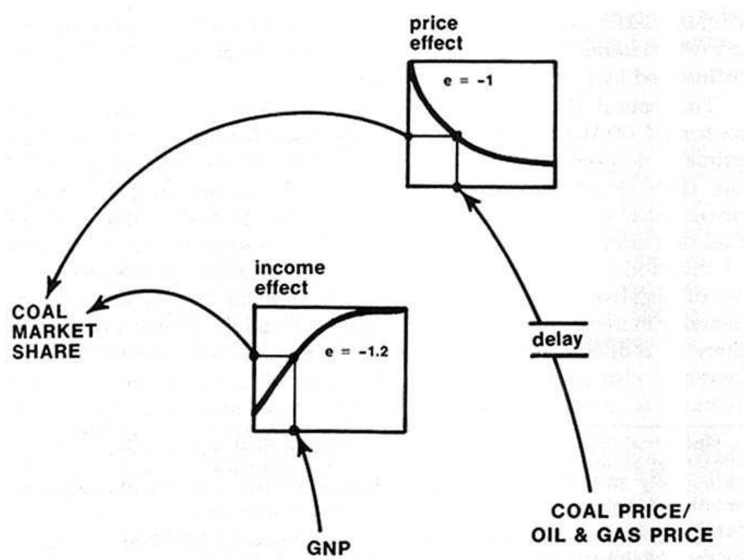


Figure 47: Coal's share-of-demand mechanism, from Figure 3-11 of Naill (1977)

Market shares for electricity and coal are controlled by consumer income (GNP) and their price relative to the major alternative, oil & gas – which is left over by the deduction of electricity's and coal's market shares. With GNP increases, the figures show that consumers tend to buy less coal and more electricity. Further, an increase in each product's price tends to decrease its market share. Finally, the delay in the figure again corresponds to the adjustment to price changes (10 years).

2. Energy Demand in the Model

As explained above, COAL2 forms the foundation of the current version of the energy demand sector. The current framework is intended as a place-holder for a more detailed and realistic demand sector.

The following sections describe the approach taken to model the global net energy demand (2.1), and the division of net energy demand into two components: heat-energy and electric-energy demand (2.2), which depends on a comparison of their average prices (2.2.1). The demand for primary energy extraction (2.2.2) is also determined here.

2.1 Net Energy Demand

As in COAL2, changes in *net energy demand* occur as a result of changes in GDP and the average energy price, according to an *income effect* and a *price effect*. The net energy demand represents the total quantity of energy demanded for consumptive purposes[73], and so includes both heat-energy and electric-energy demands.

The equation for *net energy demand* – hereafter generally called the *energy demand* – is,

$$ED(t) = r_{ED:GDP_{1990}} \cdot Q(t) \cdot SMOOTH\left(\left[{}^{AEP}/_{AEP_{1990}}\right]^{\rho_p}, 10\right)$$

where $ED$is the net energy demand, $r_{ED:GDP_{1990}}$ is the ratio of energy use to GDP in 1990 (in GJ $\$^{-1}$; note that COAL2 uses 1970 rather than 1990 as the base year), Q is the economic output from the economic sector of the full model (in 10^{12} 1990 US \$ at MER, as in DICE – although note that it is necessary to switch from 10^{12} \$ to 10^{0} \$ in the equation), $SMOOTH(\,)$ is a Vensim function that smoothes, or averages, the left-hand argument over an interval of time periods given by the right-hand argument (10 years, here), AEP is the average energy price (in \$ GJ^{-1}), and is explained below, AEP_{1990} is the "normal" energy price (in \$ GJ^{-1}), again using 1990 as a base year, and ρ_p is the price elasticity. The average energy price in 1990, AEP_{1990}, was chosen from the base run as \$4.5 GJ^{-1}, a value that agrees reasonably well with the historical data.

The ratio of energy use to GDP, $r_{ED:GDP_{1990}}$, was derived from historical data (IEA, 2007b; IEA, 2007c); the associated calculations are provided in an **Excel database** called "Historical Energy Consumption – IEA Values". The main trends in energy intensity are shown in Figure 48, and the 1990 figure is roughly 0.0101 GJ $\$^{-1}$.

[73] The *net* demand for energy services differs from the *gross* demand: the latter would also include the energy produced to account for losses from lower than 100% efficiency, transmission, own-use, and so on. Gross demand can be significantly higher than net demand, since electricity production is typically only 40% efficient, and own use and transmission losses can account for 20% further losses, for example.

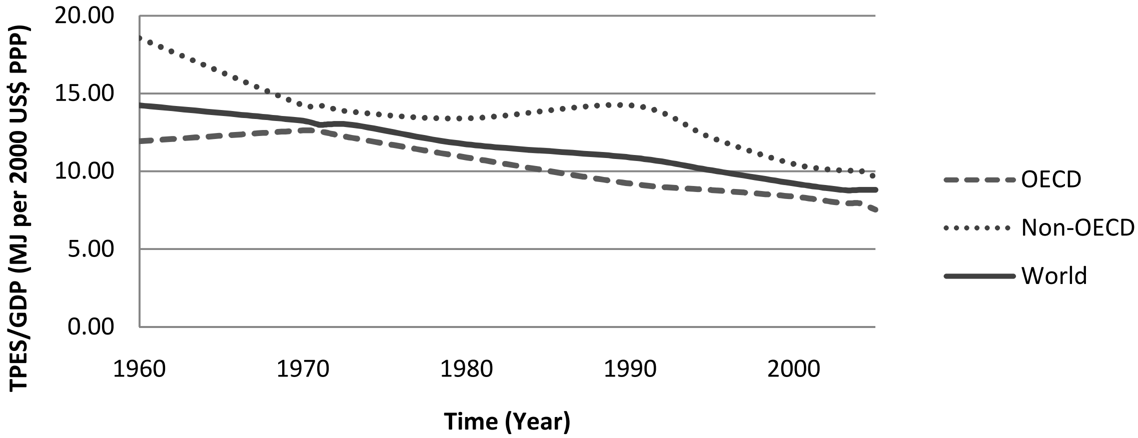


Figure 48: Total primary energy supply (TPES) versus GDP, from IEA data

To represent the energy demand calculation in Vensim, the structure in Figure 49 is used.

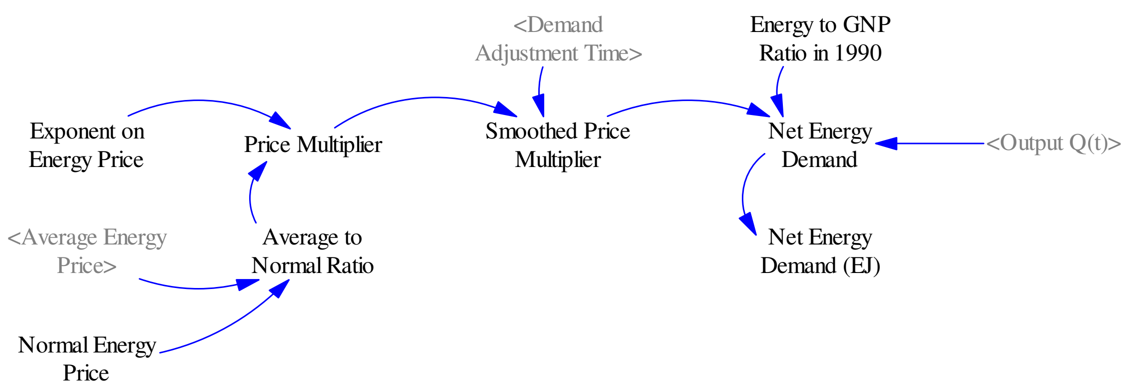


Figure 49: Basic calculation procedure for *energy demand* (in GJ yr^{-1})

2.2 Heat- and Electric-energy Demand

The model differentiates between heat-energy and electric-energy demand, so the net energy demand determined in section 2.1 must be divided into its heat- and electric-energy components. As in the previous chapter, Vensim's *allocate by priority* function is used. Recall that its structure (see Chapter Two, section 3.2.3) is,

$$allocated[x] = ALLOCATE\ BY\ PRIORITY(request[x], priority[x], size, width, available)$$

The heat *vs.* electricity calculation, whose structure is depicted in Figure 50, determines the amounts of the energy demand, *ED*, met through heat-energy production and through electric-energy production; the calculation structure has the same components as in other uses of the allocation algorithm.

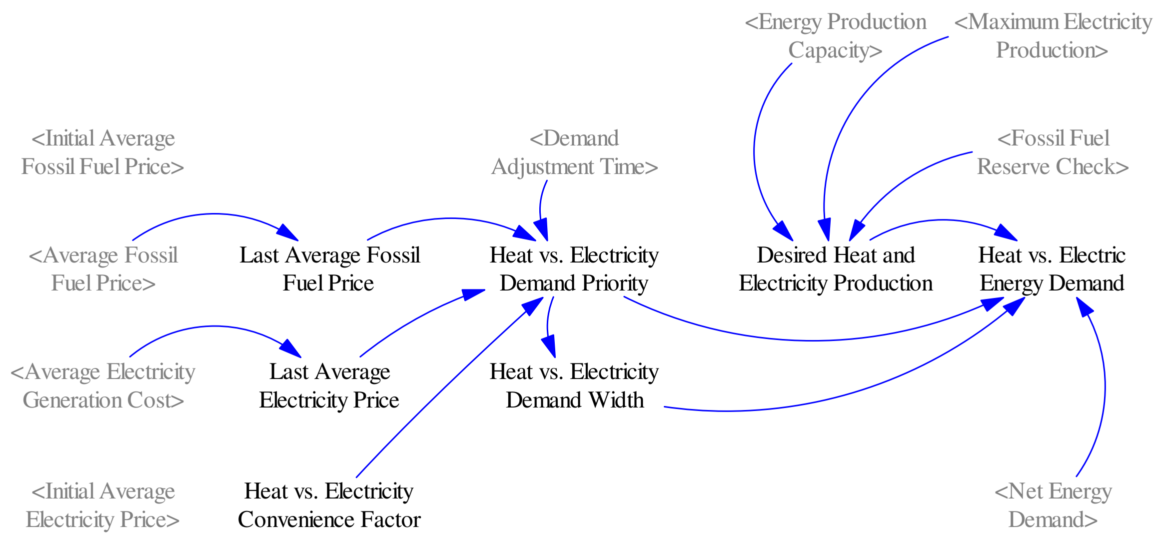


Figure 50: Basic calculation procedure for *heat vs. electric energy demand* (in GJ yr^{-1})

Several steps are involved, including determination of:

a. The desired heat- *vs.* electric-energy demands;
b. The two demand priorities;
c. The equality or exclusivity of the allocation (the *width* variable).

A new array is also introduced, which has two members: *heat*, and *electricity*.

The *request* variable in Figure 50 is the "desired heat and electricity production", or ED_{des_i}, and is given by two equations, one for *heat* and the other for *electricity*,

$$ED_{des_{heat}} = \sum_{\forall i} \varphi_{reserve_i} \cdot EP_{cap_i}$$

$$ED_{des_{electricity}} = \sum_{\forall j} ElP_{max_j}$$

In the *heat* equation, *i* represents primary production from coal, oil, and natural gas resources, while in the *electricity* equation, *j* represents secondary production from coal-fired, oil-fired, natural gas-fired, alternative, nuclear, and hydroelectric power plants. Both *desired energy production* equations are measured in GJ yr^{-1}, $\varphi_{reserve_i}$ is a binary flag (0, 1) that indicates whether fossil fuel reserves of type *i* are non-zero (i.e. are not exhausted), EP_{cap_i} is the maximum primary energy resource extraction for fuel type *i* (in GJ yr^{-1}), and ElP_{max_j} is the maximum electricity production per year for electricity production technology *j* (in GJ yr^{-1}).

The *demand priority*, or the "heat vs. electricity demand priority" in Figure 50, determines the relative attractiveness of heat-energy and electric-energy: a higher priority receives a higher fraction of its *request*. The priority is again calculated in two parts, as above, according to the following equations,

$$p_{demand_{heat}} = SMOOTH\left(\varphi_{convenience_{heat}} \cdot \frac{1}{AFC_{ff}}, 10\right)$$
$$p_{demand_{electricity}} = SMOOTH\left(\varphi_{convenience_{elec}} \cdot \frac{1}{AGC_{elec}}, 10\right)$$

where $\varphi_{convenience_i}$ is a multiplier that accounts for the relative *attractiveness* of heat-energy and electric-energy – it allows a non-economic weighting of the relative priorities, and is set to 1 and 1.25 for heat- and electric-energy respectively, indicating that electricity is 25% more attractive than heat-energy. The choice of numbers can have considerable effect on model behaviour, and their values are speculative. The average fossil fuel cost and average electricity generation cost, AFC_{ff} and AGC_{elec}, are measured in \$ GJ^{-1}, and their equations are provided below.

The *width* variable has been set in previous uses of the *allocate by priority* algorithm to either the maximum or minimum calculated priority value. In calculating the "desired heat and electricity production", ED_i, the use of the minimum priority – the most exclusive case – causes a Vensim error.[74] Therefore, the "heat vs. electricity demand width", $width_{demand}$, is calculated here as,

$$w_{demand} = MAX\left(p_{demand_i}\right) \quad \text{or} \quad w_{demand} = VMAX(p_{demand}[i!])$$

where the left-hand equation represents the logical operation, and the right-hand equation provides the Vensim equivalent – $MAX(x_i)$ returns the maximum value in an array, x, containing *i* members.

Finally, the *available* variable represents the total amount of some resource to be allocated to the various requesters. In this case, *available* is actually the energy demand, ED, which must be divided among the two competing supply types, heat and electricity. Therefore, $available = ED$.

The full equation, therefore, reads,

$$ED_i = ALLOCATE\ BY\ PRIORITY\left(ED_{des_i}, p_{demand_i}, electricity, w_{demand}, ED\right)$$

2.2.1 Average Price Calculations

Average prices play a key role in the energy demand sector, since they determine both the change in overall energy demand, ED, and the changes in relative heat and electricity demands, through p_{demand}.

The average energy price, AEP, is a production-weighted price that accounts for both primary and secondary energy. It is calculated as,

$$AEP = \frac{AFC_{ff} + AGC_{elec}}{EP_T}$$

[74] The reason for this error is worth investigating. My simulations were run on a machine using Windows Vista, which may have been the cause of the simulation errors.

where AFC_{ff} is the average cost of fossil fuels (in \$ GJ^{-1}), AGC_{elec} is the average electricity production cost (in \$ GJ^{-1}), and EP_T is the total primary and secondary energy production (in GJ). The equation for the average fossil fuel cost is,

$$AFC_{ff} = \frac{\sum_i MP_i \cdot EP_i}{\sum_i EP_i}$$

where MP_i is the market price for energy resource *i* (in \$ GJ^{-1}), and EP_i is the production of energy resource *i* (in GJ). The subscript *i* represents primary energy sources, coal, oil, and natural gas. The calculation for the average electricity generation cost is given by,

$$AGC_{elec} = \sum_j GC_{GJ_j} \cdot \varsigma_j$$

where GC_{GJ_j} is the electricity generation cost for technology *j* (in \$ GJ^{-1}) and is distinct from the generation cost, GC_i, calculated in section 3.1.3 of Chapter Two, which measured the generation cost in \$ kW^{-1} yr^{-1}, and ς_j is the market share of electricity production technology *i* (*fractional*), described in section 3.3.3 of Chapter 2. The electricity generation cost here is calculated according to $GC_{GJ_j} = GC_j \cdot \frac{1}{h/yr} \cdot \frac{1}{0.0036}$, which converts the units of GC_j first to \$ kWh^{-1}, and then uses the equivalence 1 kWh = 0.0036 GJ. The subscript *j* represents electric energy sources. Finally, the total primary and secondary energy production, EP_T, is

$$EP_T = \sum_i EP_i + \sum_j ElP_j$$

where EP_i is the production of energy resource *i* (in GJ), and ElP_j is the electricity produced by technology *j*(in GJ).

2.2.2 Primary Energy Demands

Since the *exogenous* energy demand values used to this point prescribed the amounts of coal, oil, and natural gas produced from 1980-2005 – the quantity of each fossil fuel demanded historically was simply used to determine the amount of each produced in the model – a market-based allocation between the three primary energy sources was not necessary.[75] However, with an *endogenous* calculation of heat-energy demand now in place (ED_{heat} in the *allocation by priority* equation above), it is necessary to describe the allocation of demand for heat-energy production between the three fossil fuels. The *allocation by priority* algorithm is used again, and follows the calculation procedure

[75] In contrast, the allocation of *electricity production* between the competing six technologies was never prescribed in the model, but was instead simulated endogenously – electricity production allocation was described in section 3.3.2 of Chapter 2.

illustrated in Figure 51. Its aim is to determine the "heat energy demand by fossil fuel", or ED_{heat_i}, measured in GJ yr^{-1}.

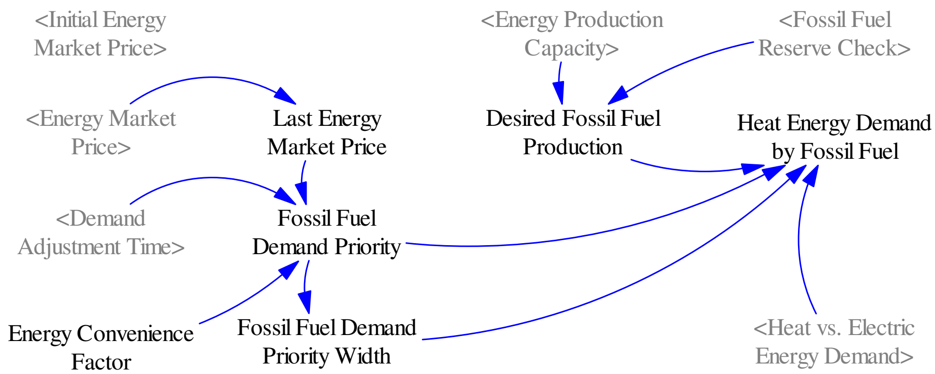


Figure 51: Basic calculation procedure for *heat energy demand by fossil fuel* (in GJ yr^{-1})

The *request* variable in the heat-energy production allocation is the "desired fossil fuel production", which is given by,

$$ED_{des\_heat_i} = \varphi_{reserve_i} \cdot EP_{cap_i}$$

and is distinct from $ED_{des_{heat}}$, which represents the desired total heat-energy production (in GJ yr^{-1}), rather than the primary fuel-specific production. In other words, $ED_{des_{heat}}$ is the sum of the three individual desired heat productions, or $ED_{des_{heat}} = \sum_{\forall\, i} ED_{des\_heat_i}$. The binary flag, $\varphi_{reserve_i}$, is also used here, and EP_{cap_i} represents the maximum energy production capacity of technology *i* (in GJ yr^{-1}).

The *priority* of each of the three primary energy sources depends on their market prices as well as the fuel's convenience. In equation form,

$$p_{heat_i} = SMOOTH\left(\frac{1}{\varphi_{convenience_{ff_i}} \cdot MP_i}, 10\right)$$

where p_{heat_i} is the priority of fossil fuel *i*, $\varphi_{convenience_{ff_i}}$ is the *convenience* multiplier associated with its market price, MP_i (in \$ GJ^{-1}), and $SMOOTH(\,)$ averages the product of the left-hand side over an interval of time periods given by the right-hand argument (10 years, here). Again, the convenience factor allows a non-economic weighting of the relative priorities, and is set to 2.6, 1, and 1.4 for coal, oil, and natural gas, respectively, so that coal and natural gas are both less attractive than their price alone would otherwise make them.[76]

[76] Without a *convenience* factor, coal, followed by natural gas, would quickly become the most important fuel source, while oil use would become less common because of its higher price. In reality, coal use has dropped steadily over the past fifty years, suggesting that factors other than prices must also be at work.

The *width* of the allocation, "fossil fuel demand priority width", is again the maximum of the calculated priorities, such that,

$w_{heat} = MAX\left(p_{heat_i}\right)$ or $w_{heat} = VMAX(p_{heat}[i!])$

where the left-hand equation represents the logical operation, and the right-hand equation provides the Vensim equivalent.

Finally, the $available$ variable represents the heat-energy component of the "heat vs. electric energy demand", ED_{heat}, so that the full equation determines the quantity of heat-energy demanded from each fossil fuel, or ED_{heat_i}, and reads,

$$ED_{heat_i} = ALLOCATE\ BY\ PRIORITY\left(ED_{des\_heat_i}, p_{heat_i}, NatGas, w_{heat}, ED_{heat}\right)$$

3. PRELIMINARY MODELLING RESULTS: ENERGY DEMAND

The following tables and graphs illustrate the results of the system structures and equation forms described in the sections above – presenting the simulation results here allows a quicker reference to both model structure and results. The figures provided below are taken from a "base case" simulation run, and are generally compared with historical data, where available. I contrast the energy demand values from the *exogenous* representation – see the results in Chapter 2, section 4.1 – with the *endogenous* values generated through the calculation approach described above (0).

3.1 Net Energy Demand

Net energy demand represents the total quantity – both heat-energy and electric-energy – of energy demanded for consumptive purposes, and is influenced by *income* and *price* effects (2.1). As explained above, the current approach toward calculating energy demand is intended to serve as a place-holder for a more accurate approach, for reasons that are apparent in Figure 52, which compares endogenous and exogenous representations of energy demand.

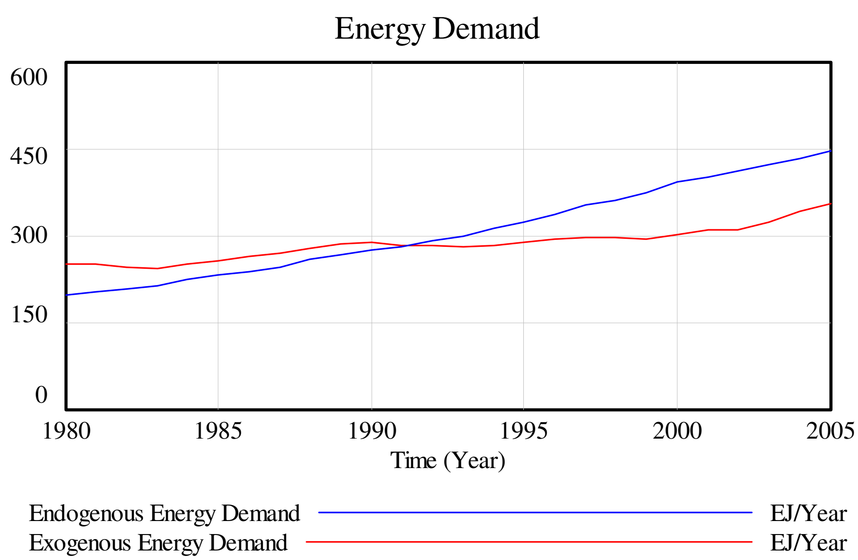


Figure 52: Net energy demand, ED, from endogenous calculation and exogenous data (in EJ yr^{-1})

Changes in the values of several variables that affect the energy demand equation, ED, are shown in Figure 53.

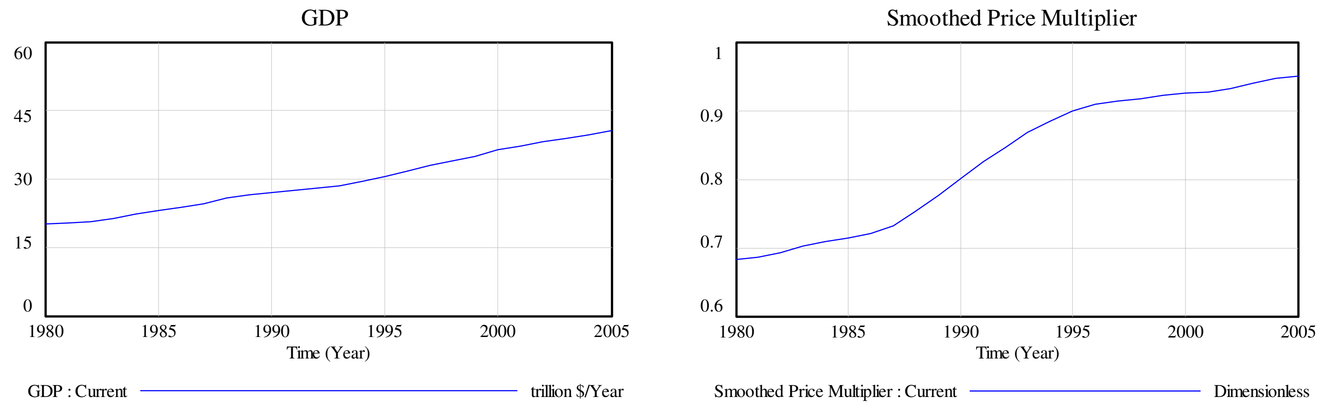


Figure 53: Key variables affecting the *net energy demand*: the *income effect* (left) and *price effect* (right)

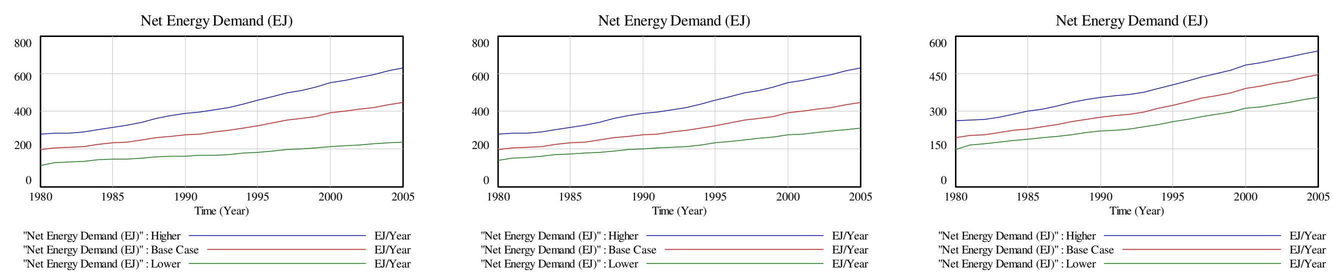
Clearly, the slopes of the line yielded by the endogenous calculation, ED, and exogenous data from the EIA (2006) in Figure 52 are quite different. However, the parameters that influence *energy demand* are tuneable. The following figure shows the effects of changes in these parameters, illustrating the means by which a closer match can be achieved. Note that any changes made to these parameters must use realistic values.

Recall from section 2.1 that the equation for *energy demand* is,

$$ED(t) = r_{ED:GDP_{1990}} \cdot Q(t) \cdot SMOOTH\left(\left[{}^{AEP}/_{AEP_{1990}}\right]^{\rho_p}, 10\right)$$

where $r_{ED:GDP_{1990}}$, AEP_{1990}, ρ_p, and 10 are explicit parameters. There is also an implicit parameter – an exponent of 1 – on the *income effect*, $Q(t)$.

Figure 54 illustrates the effects of changes to these five parameter values, showing the "base case" value as well as values above and below these – the base case is in red, the "higher" case in blue, and the "lower" case in green.



$r_{ED:GDP_{1990}}$: 0.008, 0.014, 0.020 AEP_{1990}: 2.5, 3.5, 5 ρ_p: -1.8, -1, -0.2

Delay: 5, 10, 15 *Income*: 0.97, 1.0, 1.03

Figure 54: Tuneable parameters for *energy demand*, including varied parameters and their ranges

3.2 Heat- and Electric-energy Demand

Since the model differentiates between heat and electric energy, the net energy demand determined in section 2.1 must be divided two components – a division accomplished through another application of the *allocation by priority* algorithm. Figure 55 allows a comparison of the endogenous and exogenous heat- and electric-energy demands.

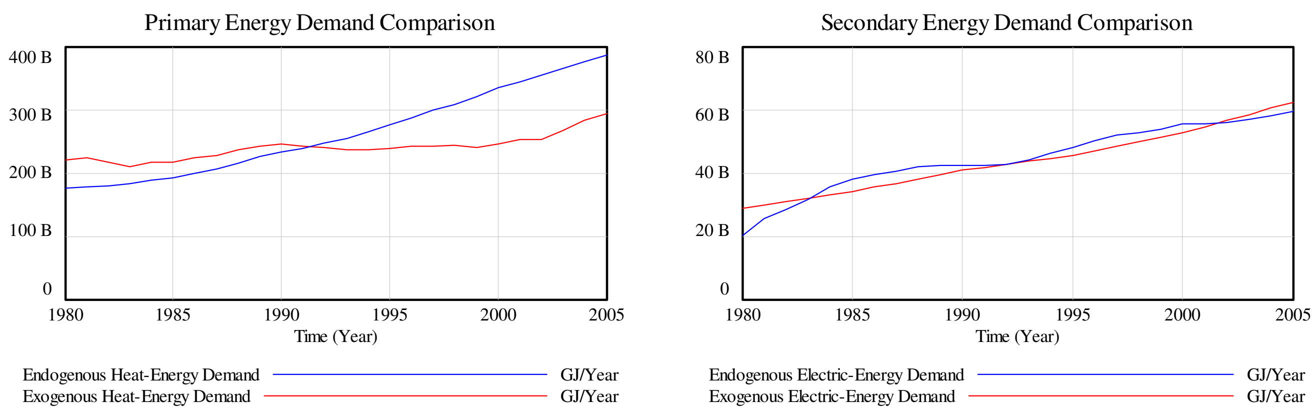


Figure 55: Comparison of endogenous and exogenous heat (left) and electric (right) energy demands (in GJ yr^{-1})

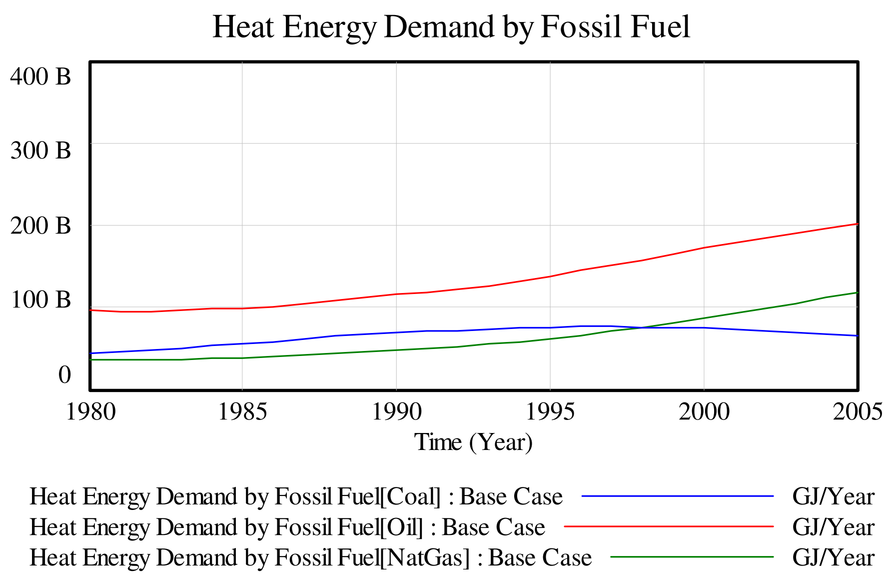
Because of the lower endogenous energy demand in Figure 51 from 1980 until the early 1990s, both calculated heat-energy and electric-energy demand are lower than the values from the historical data (EIA, 2006), but the relatively constant slope of the endogenous demand means that both are higher than the historical values by 2005. As stated in section 3.1, these values can be tuned through the parameters above, and also through the values chosen for $\varphi_{convenience_i}$ and w_{demand}(2.2).

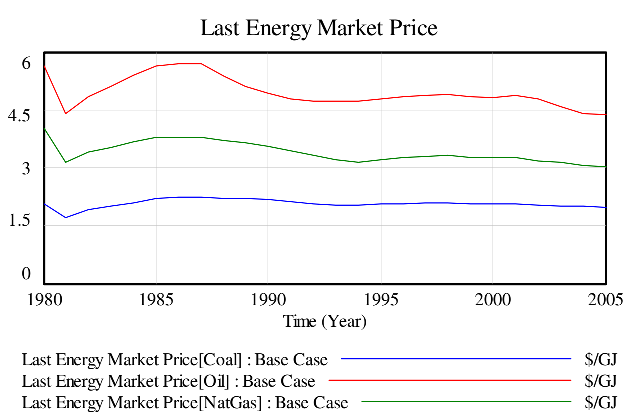
3.2.1 Primary Energy Demands

After determination of the heat- *versus* electric energy demand, heat-energy demand is further divided through the *allocate by priority* function into three components, one for each of the fossil fuels.[77]

[77] Recall that, in the case of electricity, the allocation among the six available technologies also occurs through use of the *allocate by priority* function in Vensim (see Chapter 2, section 3.3.2). The reason for the technology-specific division of electricity production in the *supply* portion of the energy sector, rather than in the *demand* portion as here, is that secondary energy users "do not care" about the original source of their energy, whereas primary energy users do. While

Figure 56 shows the fuel-specific energy demands and the fuel costs and allocation priorities that determine these values. Although the prices of coal and natural gas are clearly lower than the price of oil (bottom left-hand figure), the demand priorities are of all three are similar (bottom right-hand figure) because of the convenience factor, $\varphi_{convenience_i}$, associated with each fuel.





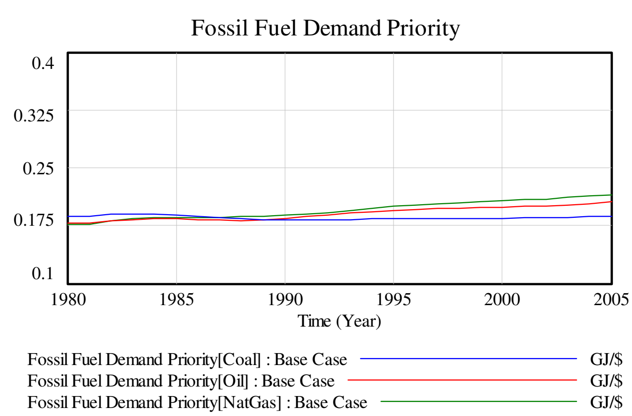


Figure 56: Primary energy sources: demand for each fossil fuel and its *market price* and *priority* causes

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primary energy consumers use coal, oil, or natural gas, secondary energy consumers use an end-product (i.e. electricity) whose original source is irrelevant.

Chapter Four: Greenhouse Gas Emissions

This chapter describes the energy-use consequences of the model. It begins with a review of basic methodological approaches towards measuring and modelling greenhouse gas emissions (1), and then describes the factors used to convert energy resource use into emissions (2). These conversion factors, along with historical fits for the emissions from minor, non-energy processes, are used to represent carbon emissions in the model (3). The chapter concludes with a set of preliminary model results (4).

1. Modelling Greenhouse Gas Emissions

Fossil fuel use releases greenhouse gases, either as a result of primary energy use – coal, oil, natural gas, or biomass combustion – or through secondary sources, which (for our purposes here) convert primary energy to electricity. Of course, where electricity comes from the combustion of fossil fuels, it also releases greenhouse gases.

In general, energy-based emissions comprise the majority of all releases of CO_2 and other greenhouse gases:

> Energy systems are for most economies largely driven by the combustion of fossil fuels. During combustion the carbon and hydrogen of the fossil fuels are converted mainly into carbon dioxide (CO_2) and water (H_2O), releasing the chemical energy in the fuel as heat. This heat is generally either used directly or used (with some conversion losses) to produce mechanical energy, often to generate electricity or for transportation. **The energy sector is usually the most important sector in greenhouse gas emission inventories, and typically contributes over 90 percent of the CO_2 emissions and 75 percent of the total greenhouse gas emissions in developed countries. CO_2 accounts typically for 95 percent of energy sector emissions with methane and nitrous oxide responsible for the balance.** Stationary combustion is usually responsible for about 70 percent of the greenhouse gas emissions from the energy sector. About half of these emissions are associated with combustion in energy industries mainly power plants and refineries. Mobile combustion (road and other traffic) causes about one quarter of the emissions in the energy sector (IPCC, 2006: Vol. 2, Ch. 1, Pg. 1.5).

According to the IPCC (2006: Vol. 2, Ch. 1, Pg. 1.6), there are three different methodological approaches towards emissions calculations[78]:

- **Tier 1 (fuel-based)**: "Emissions from all sources of combustion can be estimated on the basis of the quantities of fuel combusted (usually from national energy statistics) and average emission

[78] The IPCC (2006: Vol. 2, Ch. 1, Pg. 1.6) explains that,

> During the combustion process, most carbon is immediately emitted as CO_2. However, some carbon is released as carbon monoxide (CO), methane (CH_4) or non-methane volatile organic compounds (NMVOCs). Most of the carbon emitted as these non-CO_2 species eventually oxidises to CO_2 in the atmosphere. This amount can be estimated from the emissions estimates of the non-CO_2 gases (See Volume 1, Chapter 7).
>
> In the case of fuel combustion, the emissions of these non-CO_2 gases contain very small amounts of carbon compared to the CO_2 estimate and, **at Tier 1, it is more accurate to base the CO_2 estimate on the total carbon in the fuel. This is because the total carbon in the fuel depends on the fuel alone**, while the emissions of the non-CO_2 gases depend on many factors such as technologies, maintenance etc which, in general, are not well known. At higher tiers, the amount of carbon in these non-CO_2 gases can be accounted for.

factors... The quality of these emission factors differs between gases. For CO_2, emission factors mainly depend upon the carbon content of the fuel. Combustion conditions (combustion efficiency, carbon retained in slag and ashes etc.) are relatively unimportant. **Therefore, CO_2 emissions can be estimated fairly accurately based on the total amount of fuels combusted and the averaged carbon content of the fuels**. However, emission factors for methane and nitrous oxide depend on the combustion technology and operating conditions and vary significantly, both between individual combustion installations and over time."

- **Tier 2 (country-specific)**: Similar to Tier 1, except that "country-specific emission factors are used in place of the Tier 1 defaults. Since available country-specific emission factors might differ for different specific fuels, combustion technologies or even individual plants, activity data could be further disaggregated to properly reflect such disaggregated sources." The result should be a decrease in uncertainty of estimates. Amounts of carbon emitted in non-CO_2 gases can be taken into account in country-specific emission factors.
- **Tier 3 (high specificity)**: "Either detailed emission models or measurements and data at individual plant level are used where appropriate. Properly applied, these models and measurements should provide better estimates primarily for non-CO_2 greenhouse gases, although at the cost of more detailed information and effort."

Clearly, the work here will use a *tier one* approach, which is acceptable for CO_2 emissions calculations.

An important caveat here is that using a conversion-factor approach will work so long as all fossil fuel energy combusted adds to the atmospheric carbon dioxide concentration. Therefore, in the case of carbon capture and sequestration, modification will be necessary.

2. Conversion Factors

The IPCC (2006: Vol. 2, Ch. 1, Pg. 1.5) makes clear that *carbon dioxide* emissions depend on the carbon content of the combusted fuel. The following are potentially useful emission factor sources:

- The EIA's "Carbon (Dioxide) Emission Factors" (EIA, 2008b) provides useful conversion factors in hybrid metric-imperial units;
- The EIA's Voluntary Reporting figures (EIA, 2005) include emissions factors in pounds of CO_2 for each unit mass or volume of extracted/refined fossil fuel, or pounds of CO_2 for each million Btu; four kinds of coal, eights kinds of petroleum, and five kinds of gaseous fuel products are represented;
- Annex I (Table A1.13) in the IPCC's Special Report on CO_2 Capture and Storage (IPCC, 2005) has basic conversion factors for the major fossil fuel types, as does the Oak Ridge National Laboratory at http://bioenergy.ornl.gov/papers/misc/energy_conv.html.

In addition to the conversion factors listed above, the IPCC (2006: Vol. 1, Ch. 2, Table 2.2) provides an extensive list of available emission factor sources such as the IPCC – see IPCC Emission Factor Database, IPCC (2008) – and OECD for *default emission factors*, USEPA, European Environmental Agency, and other national institutes and laboratories for *country-specific values*, and industrial process regulators for industry-specific values.

2.1 Coal Conversion Factor

The IEA (2007a: xv) explains that,

> Coal is a family name for a variety of solid organic fuels and refers to a whole range of combustible sedimentary rock materials spanning a continuous quality scale. For convenience, this continuous series is often divided into four categories:
>
> - Anthracite
> - Bituminous Coal
> - Sub-bituminous Coal
> - Lignite/Brown Coal
>
> ...Coal quality can vary and it is not always possible to ensure that available descriptive and analytical information is truly representative of the body of coal to which it refers.

Although each of the four divisions of coal has different qualities, their carbon contents are fortunately quite similar, with US average emission factors of 227.4 lbs $CO_2/10^6$ Btu [see footnote **Error! Bookmark ot defined.**] for anthracite, 205.3 lbs $CO_2/10^6$ Btu for bituminous coal, 211.9 lbs $CO_2/10^6$ Btu for sub-bituminous coal, and 216.3 lbs $CO_2/10^6$ Btu for lignite (Hong and Slatick, 1994).[79] As generic values, the EIA (2008b) gives annual emission factors for "residential and commercial coal" (95.27 $Mt_{CO2}/10^{15}$ Btu or 25.98 $Mt_C/10^{15}$ Btu), "industrial coking coal" (93.49 $Mt_{CO2}/10^{15}$ Btu or 25.50 $Mt_C/10^{15}$ Btu), "industrial coking – other" (93.80 $Mt_{CO2}/10^{15}$ Btu or 25.58 $Mt_C/10^{15}$ Btu), and "electric power coal" (94.28 $Mt_{CO2}/10^{15}$ Btu or 25.71 $Mt_C/10^{15}$ Btu), with their averaged values in brackets.

[79] Available from http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html, last accessed Dec. 30, 2008.

According to EIA (2008b) figures, an average emission factor close to that of the coal used for *electric power* generation gives a value of 25.7 $Mt_C/10^{15}$ Btu, or 0.0244 $t_C\ GJ^{-1}$ (using 1 Btu = 0.00105506 MJ). The IPCC EFDB (2008) expresses emission factors in units of $t_C\ TJ^{-1}$; unit conversion here yields a value of **24.4 $t_C\ TJ^{-1}$**. In comparison, the IPCC EFDB (2008) has figures of 26.8 $t_C\ TJ^{-1}$ for anthracite, 25.8 $t_C\ TJ^{-1}$ for coking coal, 26.2 $t_C\ TJ^{-1}$ for sub-bituminous coal, and 26.7 $t_C\ TJ^{-1}$ for lignite; other figures, including average values and high and low extremes are in IPCC (2006: Vol. 2, Ch. 2, Table 2.2) – these average values match the EFDB values. Note that the standard assumption in IPCC sources is that 98% of the fuel is combusted.

Then, according to calculations in the "Energy Reserves" **MS Excel** database, the energy content of coal is, on average, 21.213 GJ t_{coal}^{-1}, which means that combustion of 1 ton of coal releases

1. 0.518 tons of *carbon*, for an emission factor of *0.518* $t_C\ t_{coal}^{-1}$ (EIA, 2008b); or
2. 0.541 tons of *carbon*, for an emission factor of *0.541* $t_C\ t_{coal}^{-1}$ (IPCC, 2008) [using 26 $t_C\ TJ^{-1}$, 98% combustion].

2.2 Oil Conversion Factor

The IEA (2008b: I.7) defines as inputs to refineries *crude oil* (a liquid mineral oil of natural origins – see below), *natural gas liquids* (liquid hydrocarbons recovered from natural gas processing plants or separation facilities), *refinery feedstocks* (processed oil destined for further processing), and *other hydrocarbons* (synthetic crude oil from tar sands, oil shales, coal liquefaction, and so on). Outputs from refineries, listed in the same source, are numerous, and include ethane, naphtha, motor gasolines of various types, diesel fuel, fuel oil, and so on.

In the same manner as with coal, the properties of oil are highly variable:

> Crude oil is a mineral oil of natural origin comprising a mixture of hydrocarbons and associated impurities, such as sulphur. It exists in the liquid phase under normal surface temperature and pressure and its physical characteristics (density, viscosity, etc.) are highly variable (IEA, 2008b: I.7).

The carbon contents of various types of refined oils differ to some extent, like the variations for coal. For example, motor gasoline averages 19.38 $Mt_C/10^{15}$ Btu, crude oil averages 20.18 $Mt_C/10^{15}$ Btu, petrochemical feed averages 19.37 $Mt_C/10^{15}$ Btu, kerosene averages 19.72 $Mt_C/10^{15}$ Btu, and aviation gas averages 18.87 $Mt_C/10^{15}$ Btu (EIA, 2008b). Converting to standard units yields a value of 19.13 $t_C\ TJ^{-1}$, which is similar to the IPCC EFDB (2008) average value of 20-21 $t_C\ TJ^{-1}$.

Then, according again to calculations in the "Energy Reserves" **MS Excel** database, the energy content of oil is, on average, 6205 MJ bbl^{-1}, which means that combustion of 1 barrel of crude oil releases

1. 0.119 tons of *carbon*, for an emission factor of *0.119* $t_C\ bbl^{-1}$ (EIA, 2008b); or
2. 0.125 tons of *carbon*, for an emission factor of *0.125* $t_C\ bbl^{-1}$ (IPCC, 2008) [using 20.5 $t_C\ TJ^{-1}$, 99% combustion].

2.3 Natural Gas Conversion Factor

According to the IEA (2007e: xi),

> Natural gas comprises gases occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both "non-associated" gas originating from fields producing hydrocarbons only in gaseous form, and "associated" gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included.

The carbon content of natural gas is given in EIA (2008b) as invariant, at 14.47 $Mt_C/10^{15}$ Btu, or 13.71 t_C TJ^{-1}, which is slightly different from the 15.3 t_C TJ^{-1} figure given by the IPCC EFDB (2008).

Then, according again to calculations in the "Energy Reserves" **MS Excel** database, the energy content of natural gas is, on average, 38.264 MJ m^{-3}, which means that combustion of 1 m^3 of natural gas releases

1. 5.246×10^{-4} tons of *carbon*, for an emission factor of $0.0005246\ t_C\ m^{-3}$ (EIA, 2008b); or
2. 5.796×10^{-4} tons of *carbon*, for an emission factor of $0.0005796\ t_C\ m^{-3}$ (IPCC, 2008) [using 15.3 t_C TJ^{-1}, 99% combustion].

3. Carbon Emissions in the Model

In the model, the extracted volume/mass of fossil fuel resources is multiplied with the fuel-specific emission factor to determine the total mass of *carbon emissions* from energy use per year – this approach is in line with the recommendations from the IPCC (2006: Vol. 2, Ch. 2, Pg. 2.11) for calculating *tier one* emissions (3.1). Note that it is also necessary to prescribe emissions from processes that the model does not calculate directly, such as cement production and gas flaring (3.2).

3.1 Emissions from Energy Use and Production

Carbon emissions are calculated as follows [see section 2.2.1 for an explanation of the R_{depl} term]:

- **Coal**: $E_{coal} = \kappa_{combust} \cdot \varphi_{coal} \cdot \frac{R_{depl_{coal}}}{1000} = 0.99 \cdot 0.518 \cdot \frac{R_{depl_{coal}}}{1000}$
  - **Units**: $[\text{Gt C yr}^{-1}] = [\text{t}_C\ \text{t}_{coal}^{-1}] \cdot [\text{Mt}_{coal}\ \text{yr}^{-1}] \cdot [1\ \text{Gt} / 1000\ \text{Mt}]$
- **Oil**: $E_{oil} = \kappa_{combust} \cdot \varphi_{oil} \cdot \frac{R_{depl_{oil}}}{1000} = 0.99 \cdot 0.119 \cdot \frac{R_{depl_{oil}}}{1000}$
  - **Units**: $[\text{Gt C yr}^{-1}] = [\text{t}_C\ \text{bbl}^{-1}] \cdot [\text{Mbbl yr}^{-1}] \cdot [1 \times 10^6\ \text{bbl} / 1\ \text{Mbbl}] \cdot [1\ \text{Gt} / 1 \times 10^9\ \text{t}]$
- **Natural gas**: $E_{nat\ gas} = \kappa_{combust} \cdot \varphi_{nat\ gas} \cdot R_{depl_{nat\ gas}} \cdot 1000 = 0.99 \cdot 0.000525 \cdot R_{depl_{nat\ gas}} \cdot 1000$
  - **Units**: $[\text{Gt C yr}^{-1}] = [\text{t}_C\ \text{m}^{-3}] \cdot [\text{Tm}^3] \cdot [1 \times 10^{12}\ \text{m}^3 / \text{Tm}^3] \cdot [1\ \text{Gt} / 1 \times 10^9\ \text{t}]$

I use the first-listed emission factors for each of the three fossil fuels, because they give the closest correspondence to historical emission values, as shown in the next section. The combustion factor, which states that the combustion process uses 99% of the fuel, also aids correspondence to the data.

The structure of the calculations is very simple, and is shown in Figure 57, below.

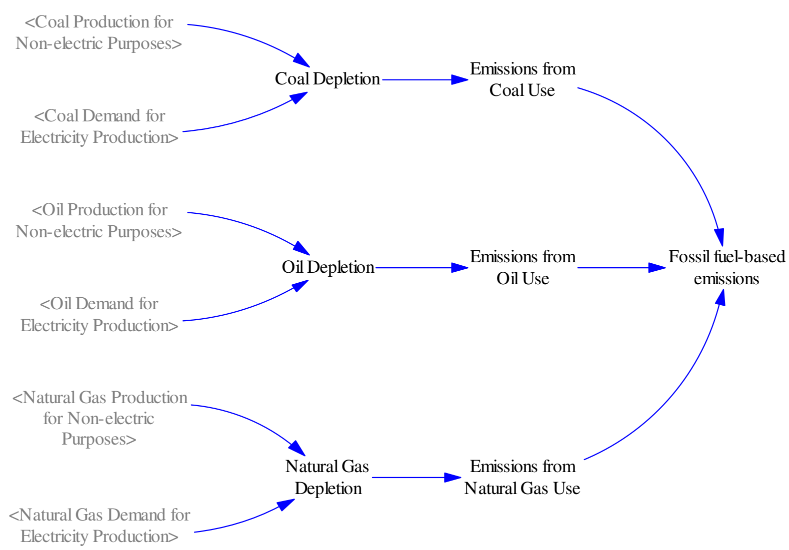

Figure 57: Basic calculation procedure for fossil fuel-based emissions (in Gt C yr^{-1})

3.2 Non-energy Emissions

For non-energy emissions (from cement production and gas flaring[80]), I prescribe their values based on historical data from Marland et al. (2008), displayed in Figure 58. **MS Excel** trendlines are fitted to the data, both as an aggregate and by individual processes – clearly an exponential fit works well for the cement data, while the fourth-order quadratic works less well for the gas flaring data.

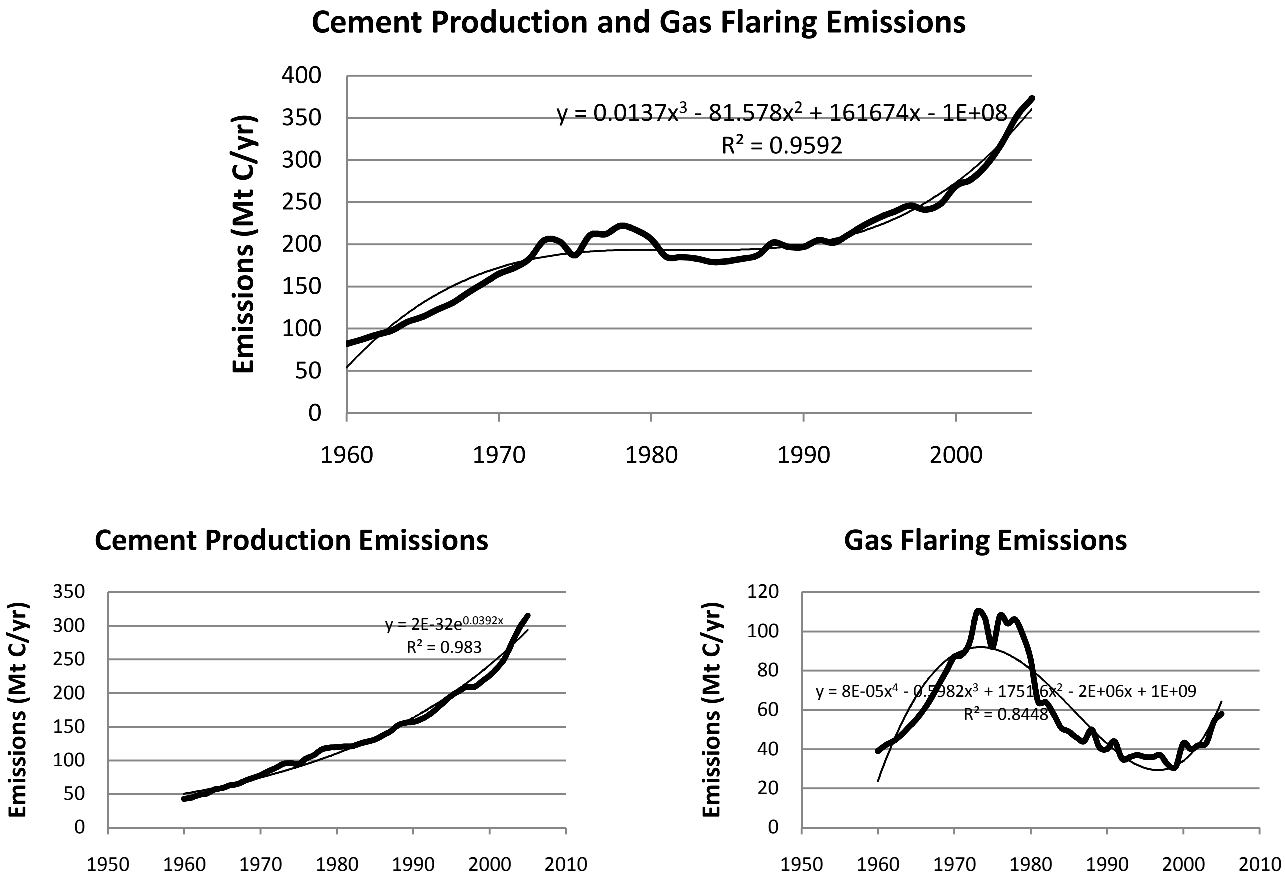

Figure 58: Carbon emissions from cement production and gas flaring, from Marland et al. (2008) data

Extrapolating the individually-fitted emissions curves from Figure 58 outwards to 2100 gives the (fairly absurd) results of Figure 59. Alternative trendlines give less impressive matches over the short term (a linear trendline for cement production has an R^2 value of 0.939, while a power-based trendline has an extraordinarily low R^2 value of 0.024), but much less extreme long-term results.

[80] In 1960, cement production and gas flaring resulted in carbon emissions of 43 and 39 Mt each; by 2005, cement-related emissions were 315 Mt, while gas flaring remained near its 1960 levels, at 58 Mt. Cement production-based emissions have increased consistently from 1960 to the present. Gas flaring peaked at 110 Mt in 1973, held relatively constant through the 1970s, and decreased to its current values by the early 1980s. Both sets of emissions were essentially identical until 1978, after which they began to diverge to their current values.

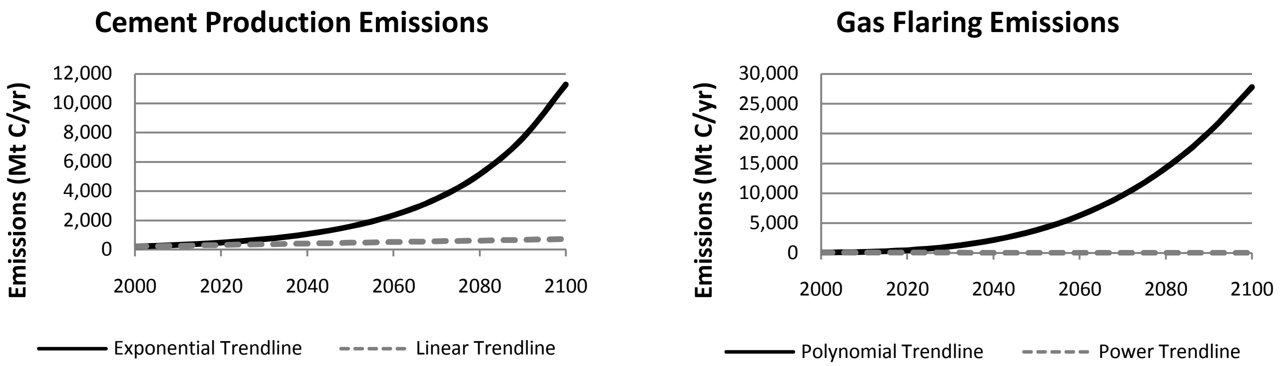

Figure 59: Carbon emissions from cement production and gas flaring – a trendline extrapolation

Since emissions from both cement production and gas flaring are unknown into the future, and since they are likely to increase little, if not actually decrease as a result of economic and policy forces, it makes little sense to use the trendlines that result in massive increases in emissions (the black trendlines in Figure 59); instead, the trendlines with lower R^2 values are used (the dashed trendlines in Figure 59).[81] Their equations are,

$$E_{cement_{\rightarrow 2005}} = prescribed$$
$$E_{cement_{2005\rightarrow}} = 5.056 \cdot t - 9884.3$$

$$E_{flaring_{\rightarrow 2005}} = prescribed$$
$$E_{flaring_{2005\rightarrow}} = 5.394 \times 10^{93} \cdot t^{-27.899}$$

In Vensim, the non-energy emissions structure appears as in Figure 60, where the *non-energy emissions* variable is the *historical* value prior to 2005, and the sum of the E_{cement} and $E_{flaring}$ values thereafter. The total carbon emissions are then the sum of the energy and non-energy emissions (from Figure 57 and Figure 60).

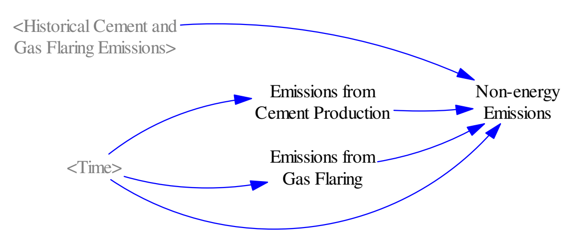

Figure 60: Basic calculation procedure for non-energy emissions (in Gt C yr-1)

[81] Since this approach has obvious shortcomings, a process-based calculation or the use of values from other studies for these emissions values would ultimately be preferable. I recommend use of historical values to 2005 – industrial emissions play a relatively small part in determining total emissions, and so their simulated value may as well be accurate – and then of calculated values thereafter (according to the equations above).

4. Preliminary Modelling Results

Using prescribed energy demand values (2.2), the simulated energy-related emissions from coal, oil, and natural gas sources – according to the equations from section 3.1 – match the historical values from Marland et al. (2008) very closely. *Fuel-specific* values are displayed in Figure 61; note that the non-energy (industrial) emissions are identical to historical values until 2005, as explained in section 3.2 – they are therefore not shown separately below.

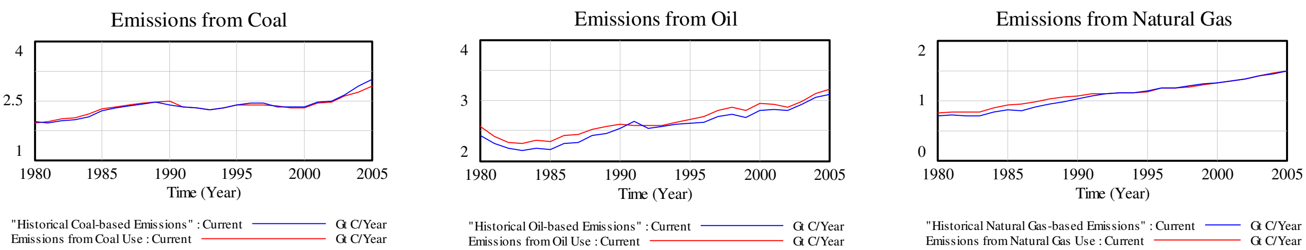

Figure 61: Fuel-specific historical and simulated energy emissions (in Gt C yr^{-1})

The correspondence between simulated and actual *total emission* (energy and non-energy) figures is displayed in Figure 62.

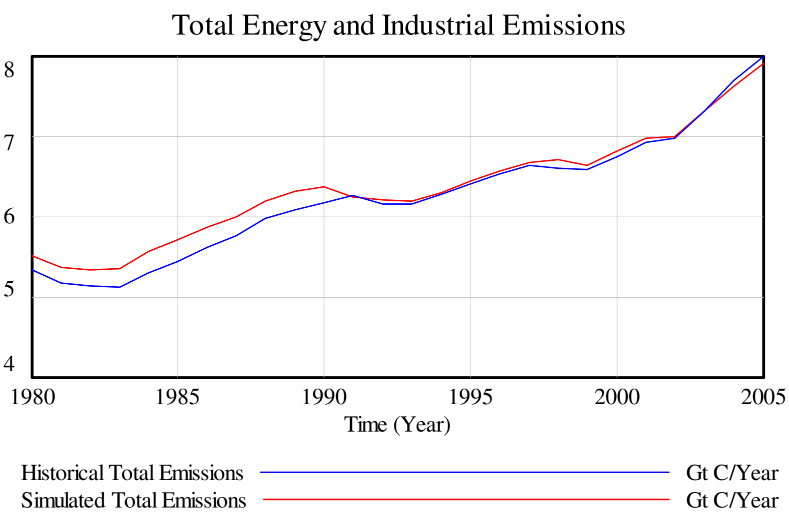

Figure 62: Historical and simulated total energy and industrial emissions (in Gt C yr^{-1})

Chapter Five: Technological Change

Technological change can be modelled **exogenously** – and has typically been modelled in this way in the past, through effects like the *autonomous energy efficiency increase* (AEEI) factor used in DICE and FREE, among others – or **endogenously**, as a result of changes in other modelled structures and system characteristics. Modelling technological change exogenously offers certain advantages: for example, assumptions are clear, and their effects are easy to see. However, most models now tend to represent technology endogenously, either as a result of cumulative *production* or installed *capacity*, or of cumulative *investment*. Since most energy-economy, climate-economy, and IAM models include various forms of endogenous technological change, there are many examples from which to choose.

Changes in technology can enter an energy model in at least five ways. Technological change serves to

- Reduce capital costs for heat-energy and electrical production,
- Increase energy extraction efficiency,
- Reduce emissions per unit energy produced (through energy efficiency increases),
- Introduce new power sources (carbon capture and storage, alternative energies, and so on), and,
- Reduce energy demand per unit GDP produced.

The current version of our model does not represent *technological change* (whether endogenous or exogenous) explicitly[82], but it does include the effects of changes in *electricity capital costs* (Chapter 2, section 3.1.4) on the *average generation cost* (Chapter 2, section 3.1.3). To model changes in *efficiency* in the same manner would not be difficult – it would simply require data about historical rates of efficiency improvements in electricity production technologies from 1960, or thereabouts, onwards. However, such approaches are exogenous, so a preferable approach would be to develop an endogenous representation of technological change that could model the same general trends in cost and efficiency.

Alternative technological options are not currently included in the model. However, their eventual inclusion is important, since tax policies or energy subsidies designed to reduce greenhouse gas emissions may encourage or even mandate the adoption of *carbon capture and storage* technologies. The current model framework can accommodate these technologies, but more data is required. A useful starting point may be the IPCC *Special Report on Carbon Dioxide Capture and Storage* (IPCC, 2005).

Reductions in energy demand with rising GDP are not included currently; however, Chapter 3, section 3.1 shows how changes in the exponent on the *income effect* can be used to represent the GDP : Energy use ratio.

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[82] Although note that the economic sector of the model does include a representation of *total factor productivity*, or A(t), based on the DICE-99 model of Nordhaus and Boyer (2000)

Rapid capacity expansions – which are also generally treated as a form of technological change in energy models – can also pose a problem: when the economic situation changes quickly (as expressed through changes in the relative prices of fuels or capital costs), models can tend to over-predict adoption of new electricity production technologies. For example, the installation of windmills may increase at an unrealistically rapid rate. Therefore, the model currently restricts the expansion of energy technologies to one-third of their present installed capacity (Chapter 2, section 3.2.4). McFarland et al. (2004) include these sorts of effects in EPPA as a *fixed factor*, which represents the availability of expertise and labour to build the desired production capacity.

Finally, it is worth noting that the approach taken in modelling technological change in the energy sector must complement the approach taken in the **economic sector** – mismatching treatments of technological change in different parts of model could cause [il]logical conflicts and, and make the model structure and behaviour more difficult to understand.

Chapter Six: Integration into the Full Model

The initial version of the model (as described in Chapters 2-5) has a start-date of 1980 to match the availability of energy data from the majority of available sources, while the larger society-biosphere-climate model to which the energy sector is coupled uses a start date of 1960. It was therefore necessary to recalibrate each component of the energy sector – energy demand, energy resources, energy economics, energy production, and energy emissions – for a start date of 1960 (1), and then to incorporate the new version of the energy sectors into the larger model (2). Some basic results from this new, full version of the model are provided at the end of the chapter (3).

1. Recalibration to 1960 Start

Changes to initial values were required for many model variables, with the changes following the (sparsely) available data as closely as possible. In several cases, the available data were "back-cast" to the 1960s using later figures and anecdotal evidence where available, since the IEA publishes data from 1971 at the earliest[83], and the EIA data at global resolution begin in 1980.

This section describes the changes necessary to recalibrate the 1980-start version of the model to a 1960 start-date, based on the five sub-sector division of the energy sector: energy demand, energy resources, energy production, energy economics, and energy emissions – although no recalibration was necessary for emissions.

1.1 Energy Demand

For energy demand, initial values for the average fossil fuel and average electricity prices are necessary, since they determine the relative heat- *vs.* electric-energy demand, while the initial global aggregate electricity orders affects the growth in electricity demand over time. Several parameters also require resetting from their 1980 values: the normal energy price, AEP_{1990}, the energy to production ratio, $r_{ED:GDP_{1990}}$, the *price effect* exponent, ρ_p, and historical coal, oil, and natural gas production values (for use in the exogenous energy demand setting).

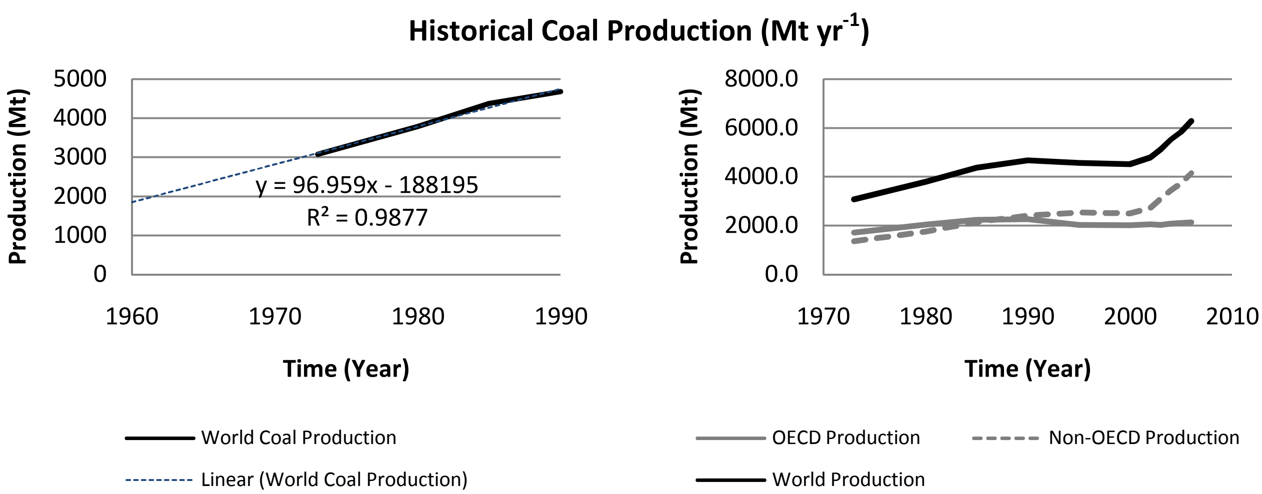
Initial average fossil fuel and electricity prices were taken from the "base case" simulation of the model. They were set to \$4.5 GJ^{-1} and \$9.3 GJ^{-1}, respectively. The approach is not perfect, but it yields reasonable results, and the values chosen are believable given the energy price graphs presented in Naill (1977) and in Chapter 2, section 4.1.3. For further information, the IEA's *Coal Information* (2007a), *Oil Information* (2008b), and *Natural Gas Information* (2007e) series provides some historical price data – and their online databases presumably offer more (see footnote 83) – and the EIA's *Annual Energy Review* (EIA, 2008a) presents historical US fossil fuel production costs.

[83] Although as mentioned in Chapter 2, section 1.1.2, the IEA (2007a) does provides detailed information about coal, oil, and natural gas production and consumption, dating back to 1960 on the online version of the resource, at http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=302 (for *coal*; accessed Jan 28, 2009). However, the databases are available only to subscribing institutions, and UWO does not subscribe.

Initial electricity orders are also unavailable, but the IEA (2005: I.62) reports that the OECD consumed roughly 1420 TWh of electricity in 1960. Assuming then that OECD use represented roughly 80% of the total in 1960 – it was 73% in 1973, and total global electricity production was 6124 TWh (IEA, 2005) – and that some production was wasted (transmission losses, and so on) gives a total initial value of 1825 TWh, or 6.57×10^9 GJ.

In the *endogenous energy demand* equation, the normal energy price, AEP_{1990}, is set to \$4.5 GJ^{-1}, which is slightly higher than the "base case" value of \$4.43 GJ^{-1}, simply because \$4.5 GJ^{-1} is a round figure (the effect of the difference on behaviour is negligible). The energy to production ratio, $r_{ED:GDP_{1990}}$, value of 0.014 GJ $\$^{-1}$ is slightly higher than the data for 1990 would suggest (Figure 48, above), since lower values give an initial energy demand that is far below historical figures – see the effects of lower ratio values in Figure 54 (Chapter 3, section 3.1). Finally, the exponent on the income effect, ρ_p, takes the same value of -0.28 as in Naill (1977).

When energy demand is prescribed (i.e. exogenous), accurate historical figures are required. For primary energy production, the IEA's *Coal Information* (2007a), *Oil Information* (2008b), and *Natural Gas Information* (2007e) series provides figures for OECD countries, non-OECD countries, and the world from 1973 (for coal), or 1971 (for oil and natural gas) onwards. To determine appropriate initial values for a 1960 start-date therefore requires "back-casting" through linear or quadratic fits to the available data. Figure 63 depicts these data fits (left-hand side figures), along with the historical, regional – OECD vs. non-OECD – divisions of production (right-hand side figures). The actual data and calculations are available in the **MS Excel database** called "Energy Reserves", which also shows the generally close fits between these data and the EIA (2006) data. Initial values for coal, oil, and natural gas production are 1845 Mt yr^{-1}, 11523 Mbbl yr^{-1}, and 0.622 Tm^3 yr^{-1}, respectively.



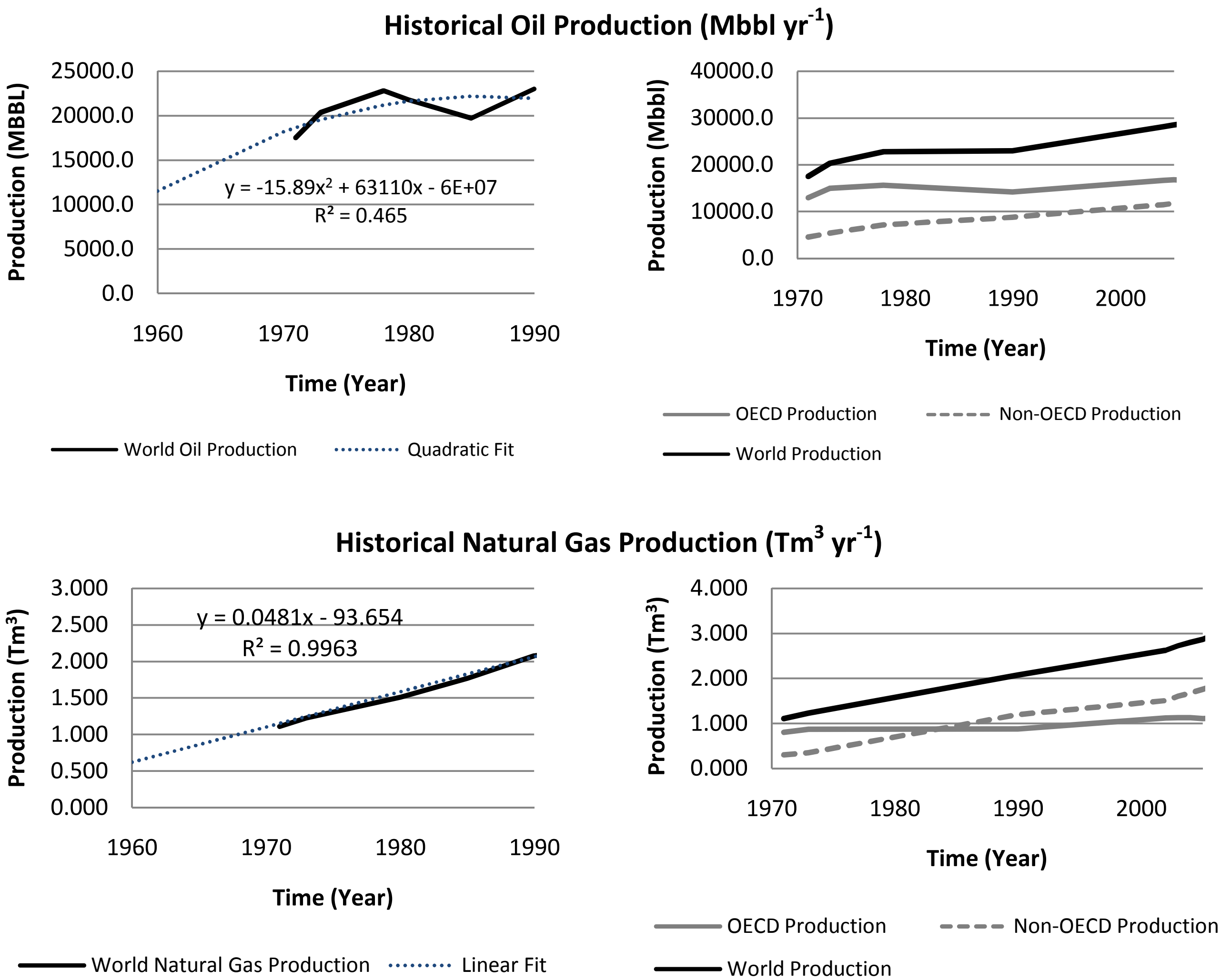


Figure 63: Historical primary energy production: data fits and regional production values (*various units*)

For secondary (electric) energy demand, the two figures for electricity production given above are used as 1960 and 1973 values, and IEA (2005) then gives values in TWh for 1980 onwards.

1.2 Energy Resources

Initial values for the non-renewable energy resources are required. Like the primary energy production values, historical *reserves* are not available for 1960, and are not even available before 1980, the earliest year for which the EIA (2006) publishes data. Earlier values are therefore calculated by using historical production values where available, and "back-cast" production values otherwise, and then adding the production to the known reserve values. Of course, discoveries over time have increased reserves; they must also be included, but in an approximate form – calculated as the difference between known, or best-fit, reserves and production – because no data are available at the global scale until 1980. After 1980, the EIA (2006) publishes discovery data for oil and natural gas, but no discovery data are provided for coal – presumably because coal reserve levels are assumed to be well-established, although see the comments below.

For coal, the aim of the calculations for 1960-1980 values was to obtain the reported 1980 reserve value of 1.02×10^6 Mt (EIA, 2006). A complicating factor was the reliability of the initial assumption that reserve values are well-known (Chapter 2, section 1.1.1). The WEC (2007) states that after extensive exploration, coal reserve levels are well established, and that only small revisions in values tend to occur; however, the IEA (2007a) states that a WEC publication from 1978 gave a significantly lower reserve value of 6.36×10^5 Mt. Assuming the discrepancy between the 1978 and 1980 figures was the result of a large discovery between 1978 and 1980 yields the coal reserve (left-hand graph), and production and discovery (right-hand graph) values for 1960-1980 in Figure 64 – note that the discovery and production graph uses a logarithmic scale, and that values to 1990 are provided to show the general patterns of behaviour. Since energy prices depend strongly on depletion dynamics (Chapter 2, section 3.1.2), this assumption clearly has implications for the calculation of coal prices. Again, the actual data and calculations are available in the **MS Excel database** called “Energy Reserves”, and the coal production from 1960 to 1980 follows the best-fit calculation in Figure 63. The initial value for coal reserves is 6.84×10^5 Mt.

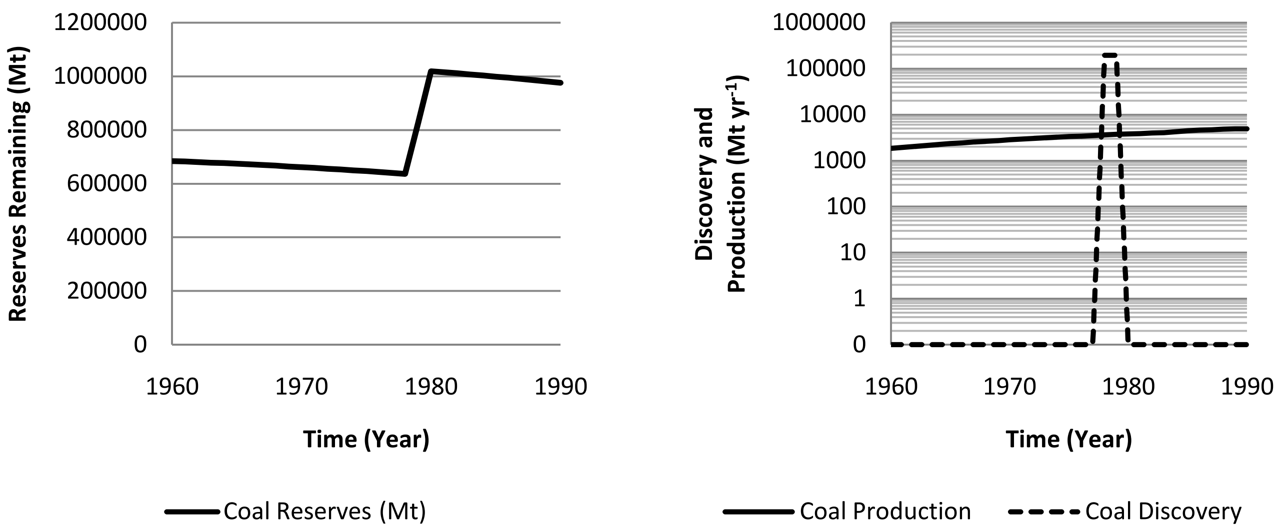


Figure 64: Calculated *coal reserves* (Mt) and *coal production and discoveries* (Mt yr^{-1})

For oil and natural gas, the approach is similar to that for coal: production values are taken from the quadratic or linear best-fits in Figure 63, and discoveries are assumed to increase the known reserve stock by 3.4% yr^{-1} – an arbitrary value based on the growth of electricity generation capacity (2005). Reserves are then "back-cast" from their known 1980 values using these production and discovery values to initial values for 1960. The approach yields initial values of 5.69×10^5 Mbbl and 51.6 Tm^3 for oil and natural gas, respectively. The calculated values for oil and natural gas reserves (left-hand graphs), and production and discoveries (right-hand graphs) are shown in Figure 65. The data and calculations are available in the “Energy Reserves” database.

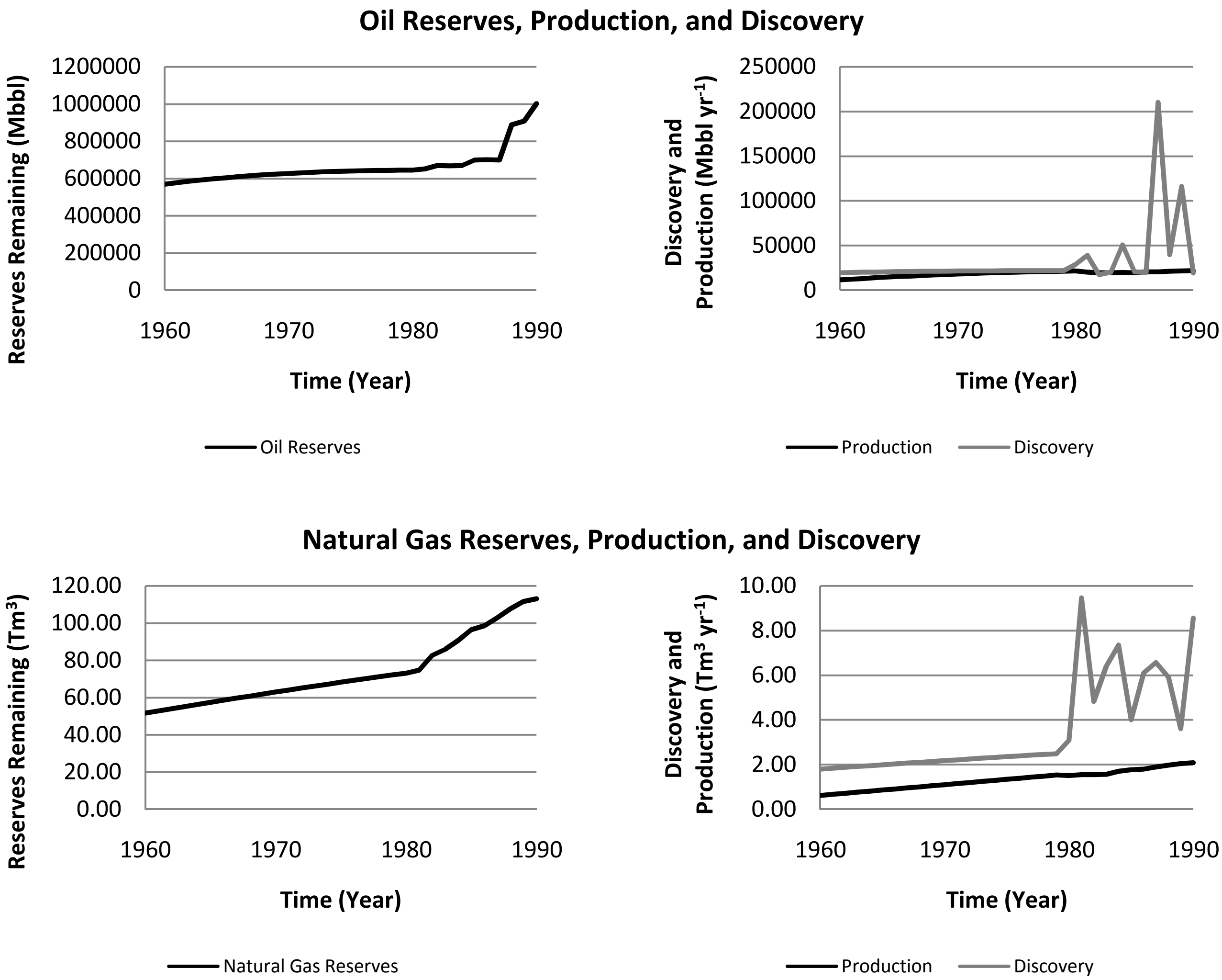


Figure 65: Calculated *oil and natural gas reserves* and *oil and natural gas production and discoveries*

1.3 Energy Production

Initial *maximum energy extraction/production capacities* and *capacities under construction* are required for both the heat-energy and electric-energy sources. While the former values are calculable from the data, at least to some extent, the latter result from model calibration. The model's initial conditions vary depending on the choice of endogenous or exogenous energy demand, because the initial energy demand values in the two cases differ significantly (see Chapter 3, sections 3.1 and 3.2), with obvious consequences for the required maximum heat-energy and electric-energy capacities.

1.3.1 Exogenous Energy Demand

Initial *heat-energy extraction capacities* for each of the three fossil fuel types can be set easily when the model runs with **exogenous energy demand**: the model must simply match historical production values, which requires a slightly higher production capacity than demanded quantity. Therefore, the initial extraction capacity for each of the three fuel types is set to 1.1 times its historical production value in 1960.

Initial *extraction capacities under construction* are unavailable from the data, so values are chosen that yield relatively smooth capacity utilization figures over the first five-or-so years of the simulation – recall that construction of new extractive capacity occurs with a delay of three years, which means that the model should (and does) reach its own equilibrium after the first several years of simulation. In selecting appropriate initial values, the aim is to avoid activating either the *bankruptcy flow* (which becomes greater than zero when the capacity grows too quickly, since too much construction of new capacity means no profit), or reaching the maximum production capacity for the resource in question (so that energy demand is not fully supplied). Of course, other variables such as market prices and production costs affect the capacity utilization, but the selection of initial values for the capacity under construction plays the most important role in ensuring that neither "extreme event" occurs. Reasonable initial values for the capacity under construction turn out to be 4 x 10^9 GJ yr^{-1}, 1 x 10^{10} GJ yr^{-1}, and 4 x 10^9 GJ yr^{-1} for coal, oil, and natural gas, respectively. Figure 66 demonstrates the effects of different values – in the "lower" case, 0 GJ yr^{-1}, and in the "higher" case, 2 x 10^{10} GJ yr^{-1} – for the *initial coal production capacity under construction*. The selected initial values clearly have little appreciable impact on the model's behaviour.

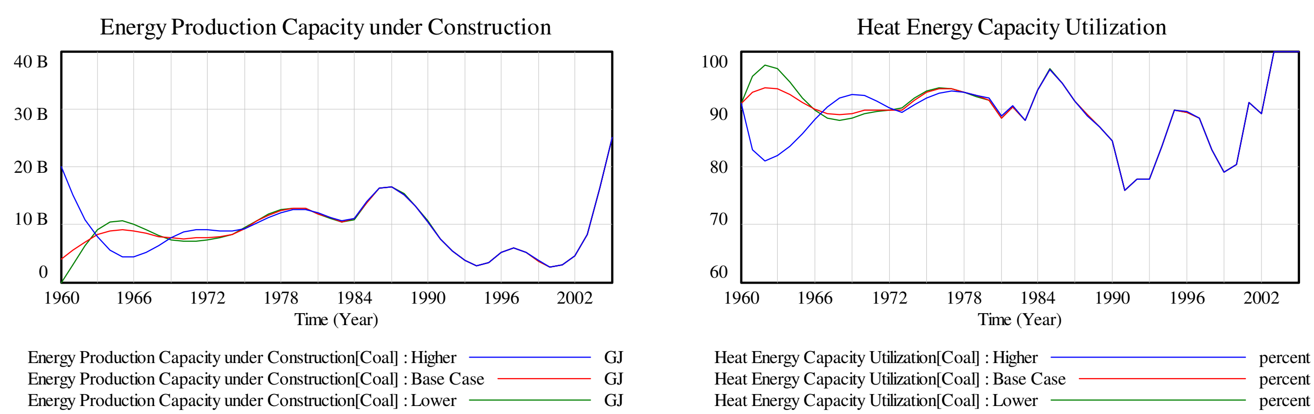


Figure 66: Effects on model of different *initial capacity construction values*, using *exogenous* energy demand

The determination of initial values for *maximum electric-energy capacities* and *production capacities under construction* poses the same problems as in the heat-energy case: historical data for 1960 are not available. Therefore, the "back-casting" approach used for calculating historical fossil fuel production values (1.1) was applied in establishing *initial maximum production capacities* – except in the case of nuclear energy, for which the International Atomic Energy Agency (2008) provides figures.

The installed electricity production capacities calculated in the **MS Excel** database called "Energy-Capital Calculations", and described first in Table 9 of Chapter 2, section 1.2.3.3, cover the period from 1974-2003. These values form the basis for the "back-cast" to 1960 shown in Figure 67. Initial maximum capacity values for each of the electricity production technologies are 335 GW, 279 GW, 94 GW, 0.5 GW, 0.9 GW, and 154 GW, for coal-, oil-, and natural gas-fired thermal capacity, alternative energy, nuclear power, and hydroelectric capacities, respectively.

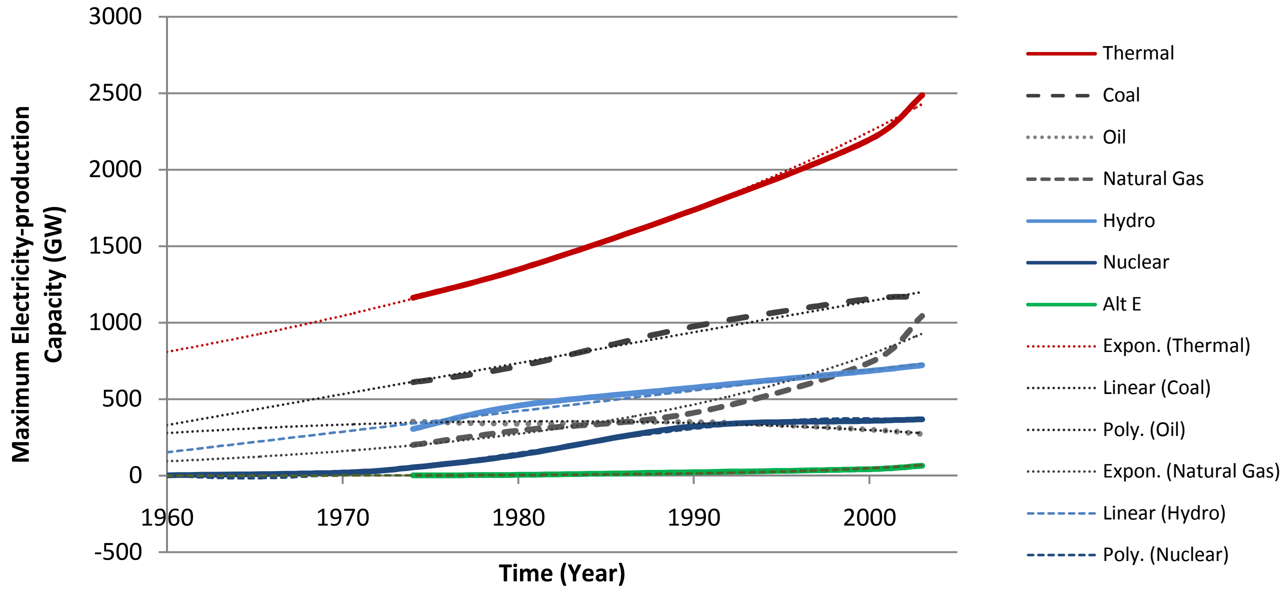
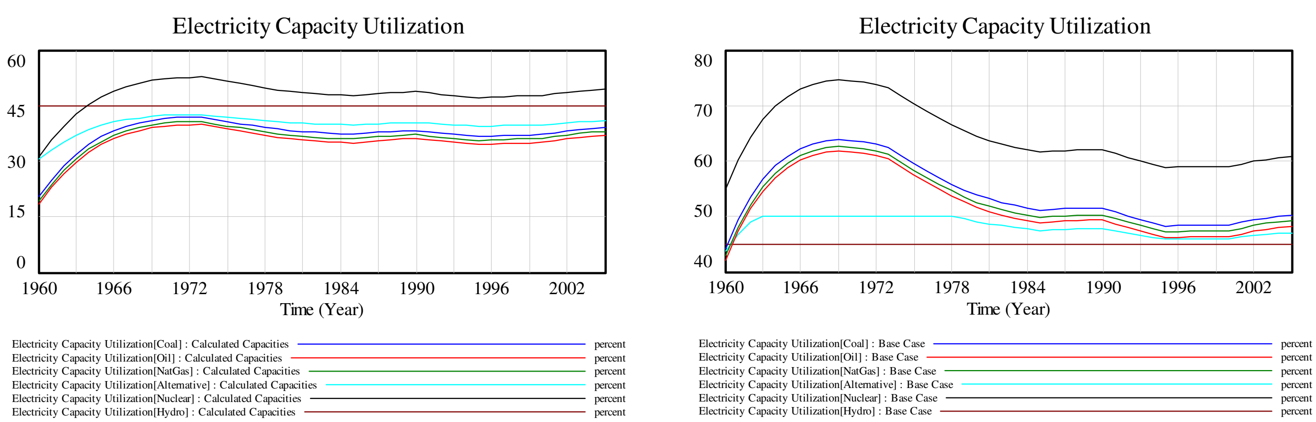


Figure 67: Best-fit "back-casts" for initial maximum electricity-production capacities, by technology (in GW)

Strangely, when the calculated values are used in the model, in conjunction with the historical electricity orders (1.1), the simulated capacity utilization values are much lower than expected – see the left-hand graph in Figure 68. Therefore, alternative values of slightly less than half the calculated values are used instead for the thermal and alternative electricity production capacities: 152 GW, 126 GW, 42 GW, and 0.25 GW for coal-, oil-, and natural gas-fired thermal capacity, and alternative energy, respectively. Their effects on capacity utilization are also displayed in Figure 68 (right-hand side).[84]



Alternative: higher, calculated initial values | **Base Case: calibrated initial values**

Figure 68: Effects of *initial maximum electricity-production capacities* values on capacity utilization (in % yr^{-1})

[84] Note that neither of the graphs in Figure 68 is "correct" in the absence of validating data, but the right-hand side values give more reasonable figures. Capacity utilization figures are easily calculated from the available data in IEA and EIA publications on electricity production capacity (in GW) and actual production (in TWh), and tend to be in the 45% and higher range. Values of 15-30%, as in the left-hand graph, are quite low but are not necessarily false.

Initial *capacity under construction* values are determined through the same sort of calibration procedure as described for the heat-energy capacity under construction. The values chosen for the *exogenous energy demand* case are 200 GW, 150 GW, 125 GW, and 0.6 GW for coal-, oil-, and natural gas-fired thermal capacity, and alternative energy, respectively. Initial nuclear and hydroelectric production capacities under construction – as well as the capacities under construction until 2005 – are prescribed to match historical data, as explained in Chapter 2, section 3.2.5.

Initial values that are too high result in maximum electricity production capacity values that are well above those of the historical data, whereas low initial values result in the installation of too little production capacity. The aim in assigning initial construction values, then, is to match historical capacity values from 1974 onwards as closely as possible. Figure 69 shows the results of low (0 GW), base case (200 GW) and high (400 GW) *initial capacity under construction values* for coal-fired electricity production capacity, as well as their feedback effects on other thermal electricity production technologies. Clearly, the values chosen have implications for all electricity production, and not just for the specific technology adjusted.

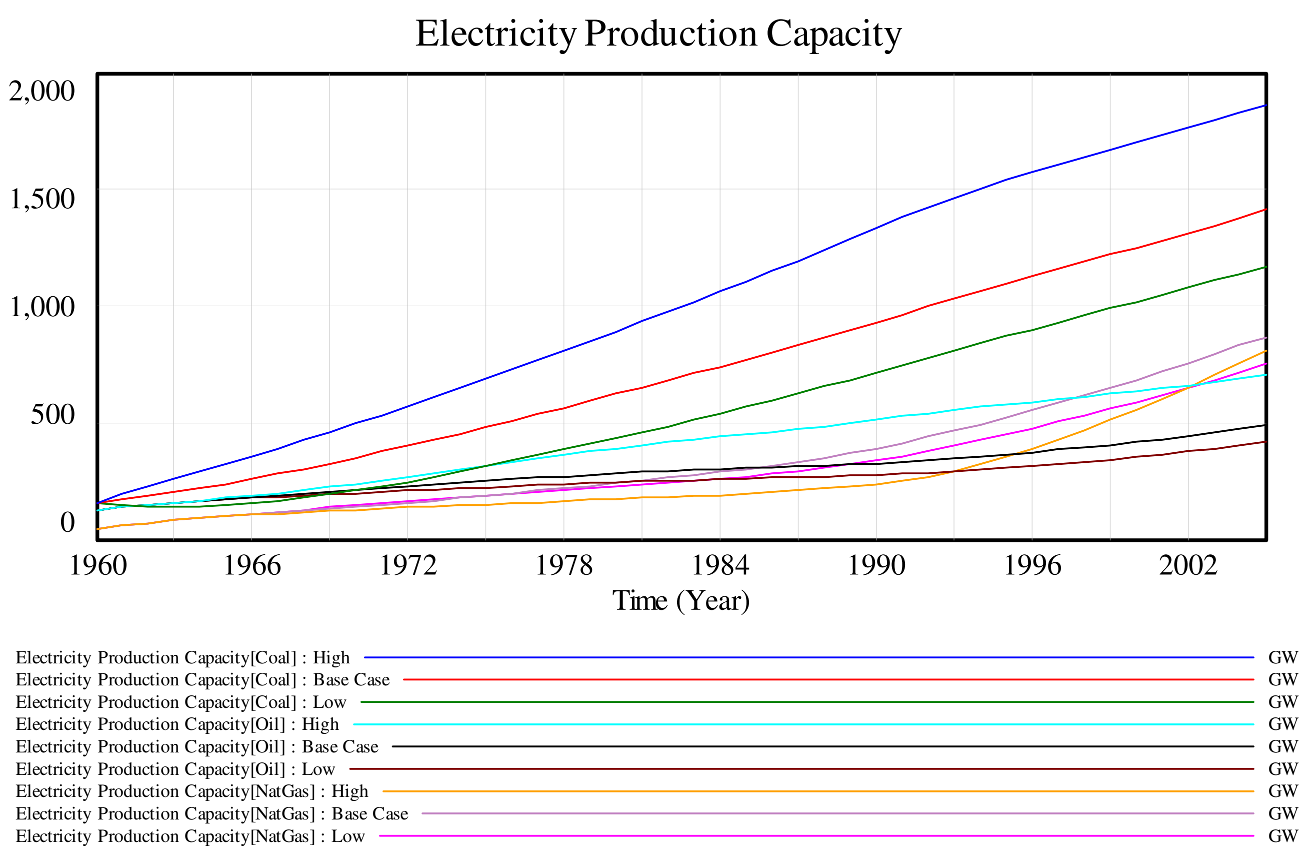
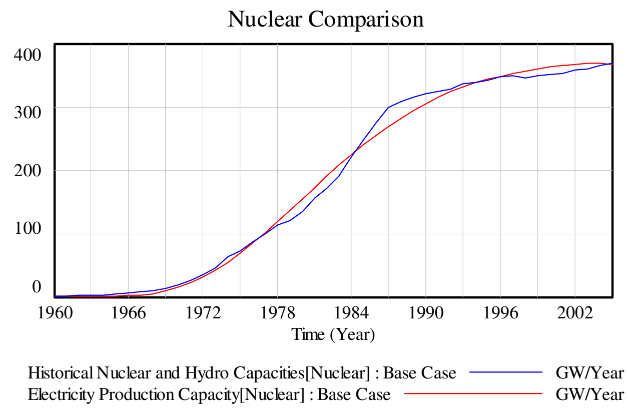


Figure 69: Effects of alternative *initial coal-fired capacity under construction* values on *maximum electricity production capacity* values of coal, oil, and natural gas-fired electricity production for (in GW)

Expansions in the maximum nuclear and hydroelectric capacities were chosen to match the IAEA (2008) data for nuclear power, and the best-fit line in Figure 67 for hydroelectric capacity. The annual capacity expansion values are too numerous to list (forty-five values from 1960-2005 for each technology)[85], but the resulting match is shown in Figure 70. It is possible to obtain better matches to historical data, but the roughly logistic-shaped curve in the nuclear capacity graph (left-hand) cannot be simulated with constant capital construction times, for example – an alternative might be the use of variable construction times, as in Table 8; however, the model currently uses constant values. Initial capacity under construction values of 0.9 GW and 69 GW were used for nuclear and hydroelectric power, respectively.



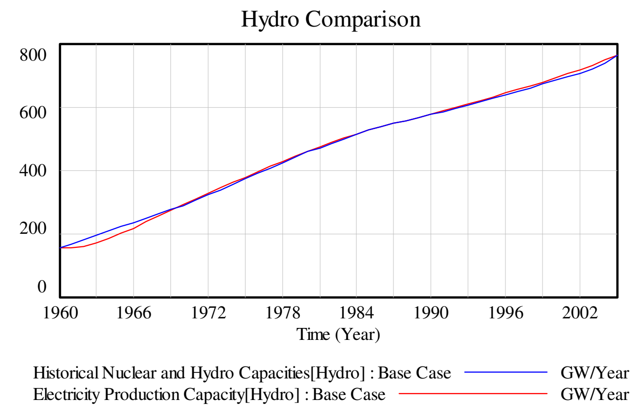


Figure 70: Comparison of historical and simulated nuclear and hydroelectric production capacities (in GW)

1.3.2 Endogenous Energy Demand

In the case of **endogenous heat-energy demand**, the situation changes considerably: the correct selection of initial values for primary energy extraction capacity has an appreciable impact on the model's behaviour, since greater production capacities lead to lower market prices and thus higher energy demand in the future. However, the lack of historical data means that there is no recourse but to choose the best values possible. The aim in selecting *initial maximum extraction capacity* and *capacity under construction* values is to obtain as smooth a curve as possible in the capacity utilization figures, and to avoid the two "extreme events", as explained above. Appropriate values turn out to be 1.4×10^{10} GJ and 2×10^{9} GJ yr^{-1}, 2.9×10^{10} GJ and 6×10^{9} GJ yr^{-1}, and 2.5×10^{10} GJ and 5×10^{9} GJ yr^{-1} for coal, oil, and natural gas maximum extraction capacities and capacities under construction, respectively. Since the two initial values interact, they were chosen in tandem.

The effects of high and low initial values for both *maximum capacities* and *capacities under construction* are illustrated in Figure 71 in the case of coal; they demonstrate the sorts of behaviour that a good calibration will prevent. In the top, left-hand graph, the drop in the capacity utilization for the "higher" case is the result of the introduction of too much extraction capacity in the first three years of the simulation period, while the resulting higher net energy demand in the top right-hand graph stems from lower energy prices because of excess capacity – recall that lower prices drive higher demand. In the bottom graphs, the "base case" value leads to a capacity utilization that remains just below 100% (peaking at 98.7%), while the other two values overshoot; furthermore, the net energy

[85] The values are available in the Vensim model, under the variable "prescribed nuclear and hydro capacity expansion".

demand in the bottom, right-hand graph shows far less sensitivity to differences in initial maximum capacity than it does to the initial capacity under construction.

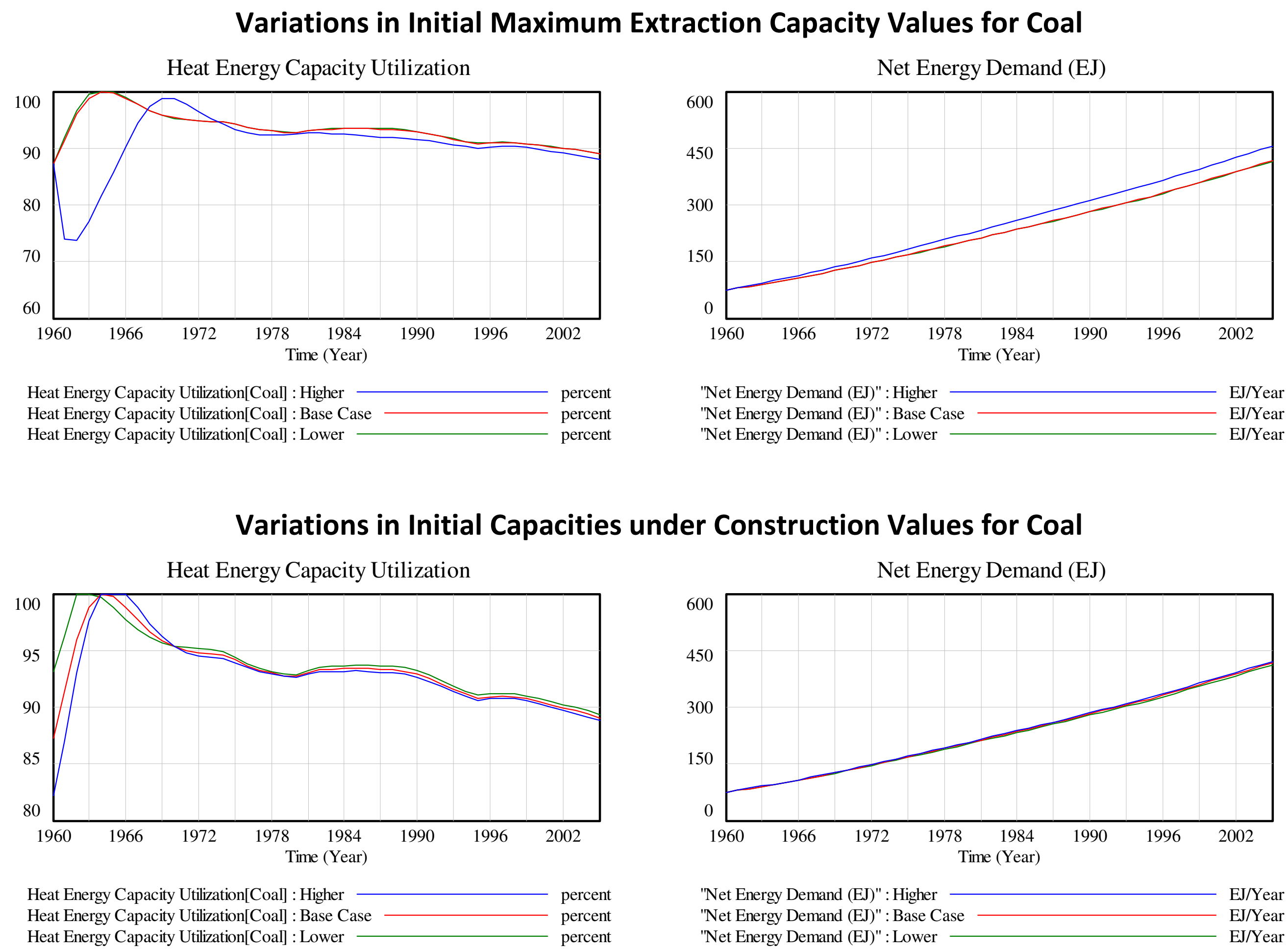


Figure 71: Effects on model of different *initial capacity construction values*, using *endogenous* energy demand

In the case of the *maximum electric-energy capacities* and *production capacities under construction*, the initial capacity values calculated in the **MS Excel** database called "Energy-Capital Calculations" are used: 335 GW, 279 GW, 94 GW, 0.5 GW, 0.9 GW, and 154 GW, for coal-, oil-, and natural gas-fired thermal capacity, alternative energy, nuclear power, and hydroelectric capacities, respectively. For the *production capacities under construction*, values of 300 GW, 175 GW, 100 GW, 0.6 GW are chosen for coal-, oil-, and natural gas-fired thermal capacity, and alternative energy, respectively. They result in the production capacity and capacity utilization values shown in Figure 72.

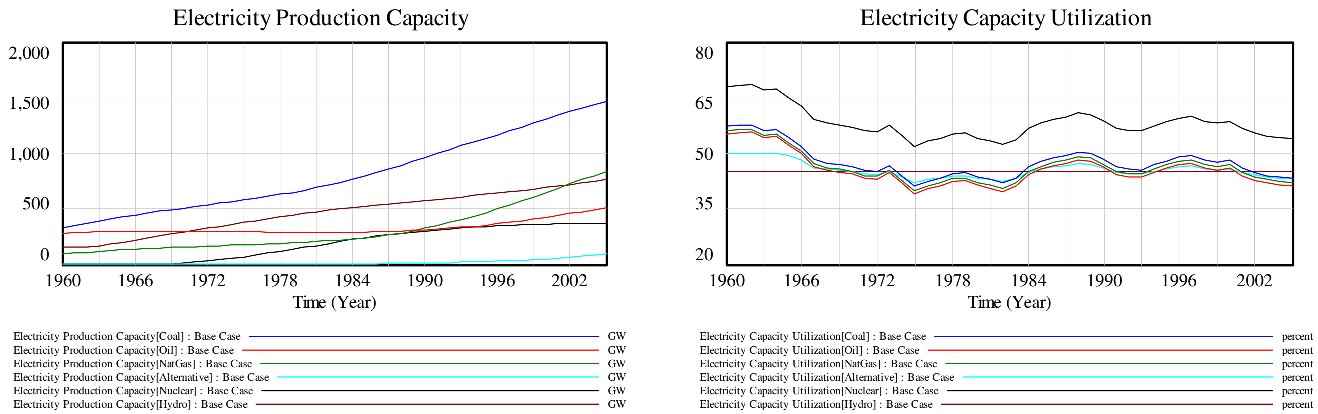


Figure 72: Maximum electricity production capacity and capacity utilization, for *endogenous energy demand* (in GW and % yr^{-1}, respectively)

1.4 Energy Economics

Initial values for the heat-energy *market prices*, and *production costs* (Chapter 2, section 2.2.2.2), and for the *electricity capital costs* (Chapter 2, section 3.1.4) are required. Both affect allocation decisions for investment funds, particularly when energy demand is calculated *endogenously*.

In terms of market prices and production costs, differences in initial values have little effect on model behaviour when energy demand is modelled *exogenously*, since primary energy production follows the historical trends, regardless of the calculated values of the economic variables; however, their impact is not zero, since differences in the variable cost of electricity production will affect the allocation of investment to different electricity production technologies (Chapter 2, section 3.2.4). In contrast, market prices and production costs can have a significant effect on model behaviour in the case of *endogenous energy demand*, since they affect not just allocations of invested funds into specific electricity production technologies, but also expansions or contractions in the primary energy extraction capacity for each fossil fuel.

The values used for initial market prices are \$2.2 GJ^{-1}, \$5.6 GJ^{-1}, and \$4 GJ^{-1}, for coal, oil, and natural gas, and are intended to be representative of historical price differences (see also Chapter 2, section 4.1.3 for a discussion of sources of historical energy price data). These values also cause relatively smooth changes in energy market prices over the first several years of the simulation period – in other words, they lead to a smooth model equilibration, as shown in Figure 73. For initial production costs, the values used are \$1.9 GJ^{-1}, \$5.2 GJ^{-1}, and \$3.7 GJ^{-1}, again for coal, oil, and natural gas, respectively. These values were also chosen to reflect historical values to the degree possible, and to result in an initial profit for energy producers (price > cost). Changes in production costs over time are shown in the right-hand side of Figure 73; note that production costs decrease over time because discoveries of energy reserves are greater than depletion effects from resource extraction.

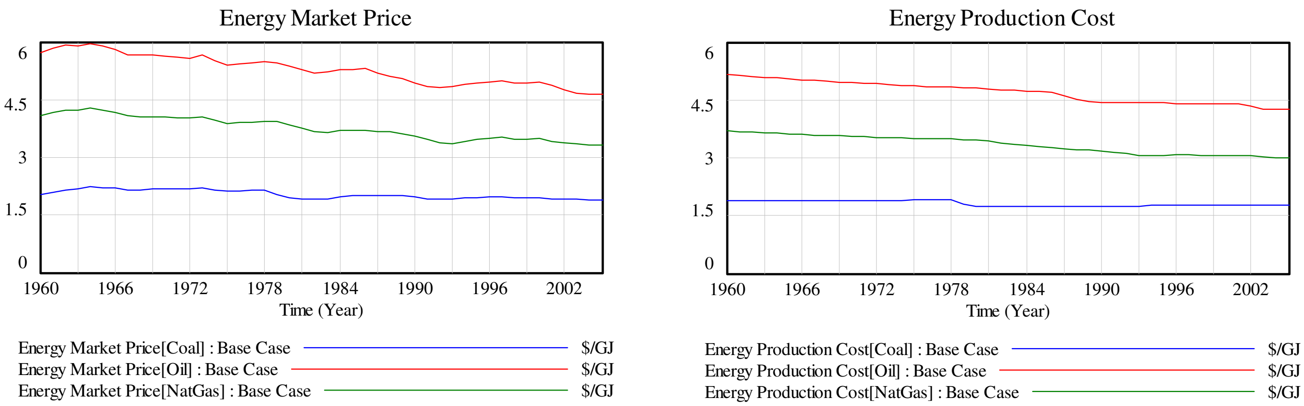


Figure 73: Energy *market price* and *production cost* values over the period 1960-2005 (in \$ GJ^{-1})

In the case of electricity capital costs, changes in their values over time affect the model's behaviour strongly, regardless of whether energy demand is modelled endogenously or exogenously. This dependence of behaviour on capital costs is a result of the use of market mechanisms (differences in generation costs – again, see Chapter 2, section 3.2.4) to determine the relative levels of investment into thermal and alternative-energy electricity production technologies. In other words, the *fractional allocation* of investment has no dependence on energy demand (although note that the *total* investment funds, in monetary terms, do depend on energy demand).

Because energy demand and initial production capacity values differ considerably between simulations using endogenous and exogenous energy demand, electricity capital costs can differ as well. Table 23 summarizes initial electricity capital costs, their periods of change, and the annual changes during those periods – only the initial electricity capital costs are different with alternative energy demand values. The changes in cost that result from the increases or decreases in technology costs over the prescribed duration result in the values in Table 13. Note that the discussion of capital costs in Chapter 2, section 1.2.3.2 gives some qualitative support for the values in Table 23, but that actual quantitative values are unknown.

Table 23: Initial electricity capital costs and their changes over time for *exogenous* and *endogenous* demands

	Exogenous Energy Demand		Endogenous Energy Demand	
Technology	Initial Value	Cost Changes with Duration	Initial Value	Cost Changes with Duration
Coal-fired	\$1816 kW^{-1}	1960-1980: \$30 kW^{-1} yr^{-1} ↓	\$1516 kW^{-1}	1960-1980: \$30 kW^{-1} yr^{-1} ↓
Oil-fired	\$555 kW^{-1}	N/A	\$555 kW^{-1}	N/A
N. Gas-fired	\$2100 kW^{-1}	1960-1975: \$10 kW^{-1} yr^{-1} ↓	\$2100 kW^{-1}	1960-1975: \$10 kW^{-1} yr^{-1} ↓
		1975-1990: \$80 kW^{-1} yr^{-1} ↓		1975-1990: \$80 kW^{-1} yr^{-1} ↓
		1990-2010: \$10 kW^{-1} yr^{-1} ↓		1990-2010: \$10 kW^{-1} yr^{-1} ↓
Alternatives	\$3077 kW^{-1}	1960-2015: \$40 kW^{-1} yr^{-1} ↓	\$3077 kW^{-1}	1960-2015: \$40 kW^{-1} yr^{-1} ↓
Nuclear	\$225 kW^{-1}	1980-2005: \$50 kW^{-1} yr^{-1} ↑	\$255 kW^{-1}	1980-2005: \$50 kW^{-1} yr^{-1} ↑
Hydro	\$860 kW^{-1}	N/A	\$860 kW^{-1}	N/A

The values in Table 23 were chosen so that the simulated changes in the production capacities of each technology were as similar as possible to the historical capacities in Table 20. Figure 74 compares the historical electricity production capacity values with the simulated values for both exogenous and endogenous energy demand values.

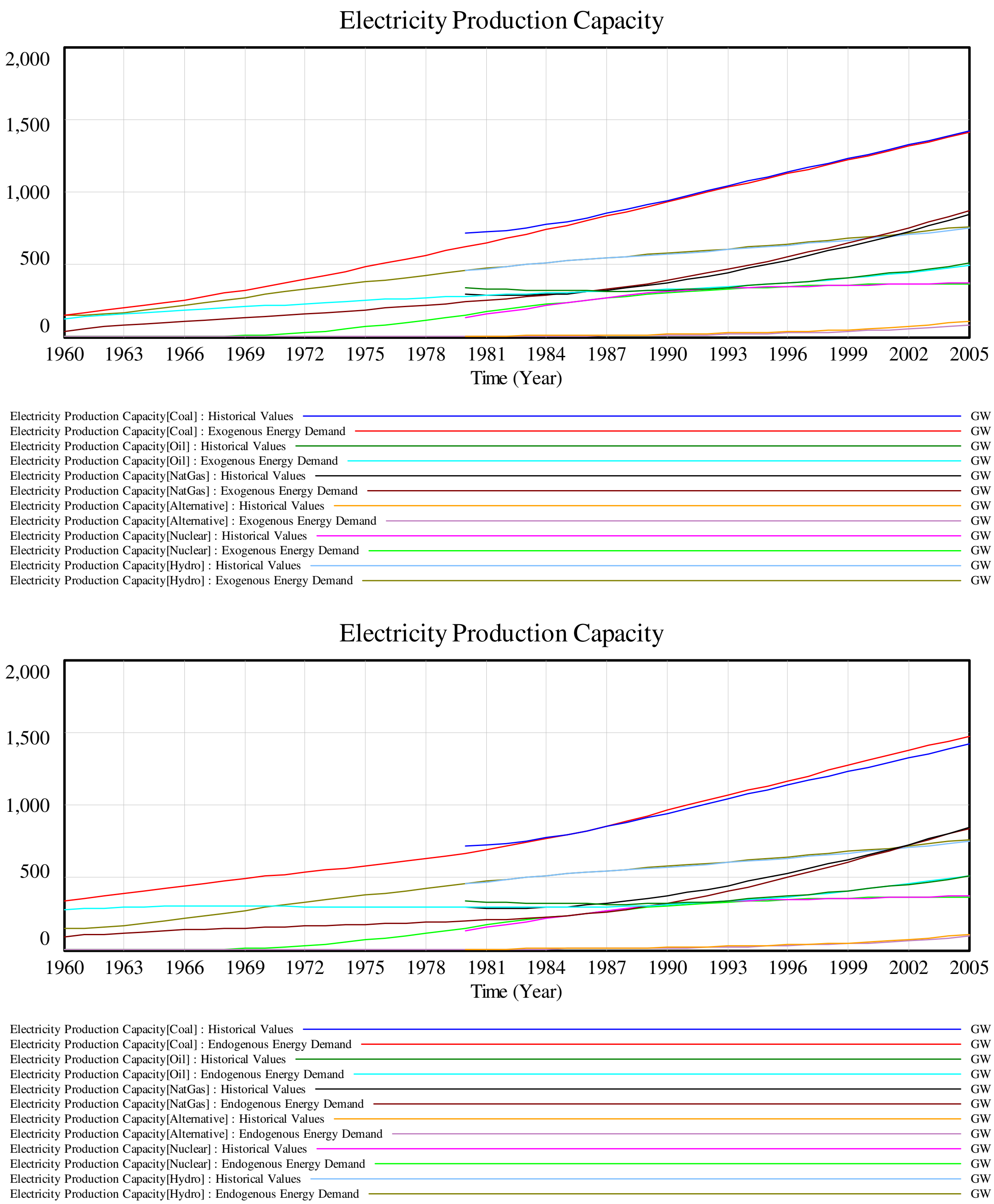


Figure 74: Comparison of historical and simulated electricity production capacities for *exogenous* (top) and *endogenous* (bottom) energy demand (in GW)

2. Integration of 1960-Start Version into Full Model

Completion of the model recalibration to a 1960 start-date means that the energy sector model is ready for integration into the complete, multisectoral model described in Davies (2007) and Davies and Simonovic (2008). Like the rest of the intersectoral connections in the model, the interaction of the energy sector with the other model sectors occurs through several *key variables*.

The three key variables that connect the energy sector with the rest of the model are industrial emissions, energy demand, and electricity production, as shown in Figure 75; the associated structural changes required to the model to incorporate the new energy sector mean that,

- Industrial emissions as input to the global **carbon cycle** now come from the *emissions* component of the **energy sector**, rather than from the emissions component of the DICE model;
- Endogenous *energy demand* in the new **energy sector** depends on the *economic output* variable simulated in the **economic sector** of the model, which previously had no explicit representation of energy use;
- Industrial surface water demand, both *withdrawals* and *consumption*, in the **water use** sector of the complete model now depend on the explicitly simulated *electricity production* variable in the energy production section of the **energy sector**, rather than on historical values extrapolated linearly outward from 2005-2100.

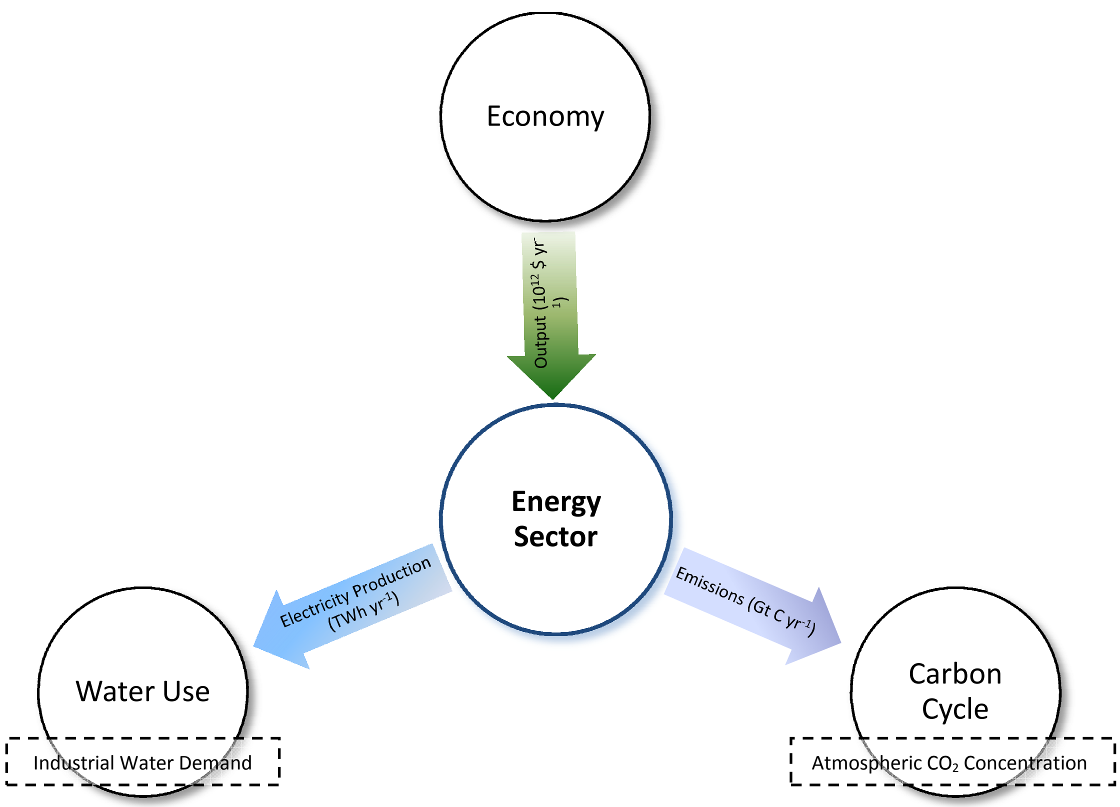


Figure 75: Integration of energy sector into the complete model

To represent the carbon cycle-energy sector interaction, several significant changes are required in the structure of the larger model. First, the complete society-biosphere-climate model uses the DICE model's (Nordhaus and Boyer, 1999; Nordhaus and Boyer, 2000) energy-economy representation, which generates emissions based on changes in economic production and carbon tax policy – thus, energy systems are not modelled explicitly; instead, their effects are modelled as a function of economic activity. In contrast, the new energy sector generates emissions based on the simulated use of primary and secondary energy sources, and so explicitly represents the causes of changes in carbon emissions. Therefore, the new energy sector replaces the simplified representation of energy/emissions in DICE, which is consequently removed from the model.

Second, the current society-biosphere-climate model has several *duplicate* sectors: two climate sectors, two carbon sectors, two economic sectors, and two energy/emissions sectors. These duplications allow identification, and quantification, of the effects of carbon tax policies on model behaviour, where one set of the duplicate sectors acts as a baseline for comparison, and the other set simulates the effects of the chosen policy. Since the new energy sector has five components (demand, resources, economics, production, and emissions), the replication of the *duplicates-based* baseline-to-policy comparison structure in the older model would require the addition of not five, but ten new model components, with considerable consequences for both model simulation time and complexity. More importantly, the strength of the DICE approach is its ability to *quantify* the effects of taxation policies on the overall *welfare* of society. With the significant changes to the model structure that result from the incorporation of a new energy sector, the realism of this quantification is likely reduced or even eliminated. For these reasons, the duplicate structure has been removed from the model. Note that it could be reintroduced without a great deal of effort, but that its reintroduction would not necessarily add to the value of the model.

The connection between the economic sector and the energy sector is through *endogenous energy demand*: economic output is the driver of changes in energy demand, so that as output rises, energy demand rises as well.[86] When energy demand is prescribed exogenously, there is no connection between the economy and the energy sector – a situation that has obvious consequences for the realism of the simulated results.

Finally, industrial water demand (both withdrawals and consumption) depends on electricity production. The substitution of endogenously simulated electricity production for the exogenous prescription in the older version of the complete model is straightforward: the old exogenous variable is deleted, and replaced by the new energy sector *actual electricity production* variable (which is measured in TWh yr^{-1}, as was the exogenous variable).

The mathematical equations altered by the incorporation of the energy sector in the larger society-biosphere-climate models are given below, beginning with the emissions to the carbon cycle,

[86] Furthermore, economic output and energy production capacity must also be connected, eventually. Economic growth is the source of investment funds for expansions in primary energy extraction capacity and secondary energy production capacity. However, the feedback connection of this investment – in other words, investment of funds in electricity production capacity does not preclude investment in economic capital as well, and so the same money can therefore be invested *twice* – is not yet modelled.

$$\boldsymbol{E_{Ind}(t)} = E_{coal} + E_{oil} + E_{nat\ gas} + E_{cement} + E_{flaring}$$

where $E_{Ind}(t)$, in bold type, represents the carbon cycle sector's received emissions from industrial and energy-based processes (in Gt C yr^{-1}), and the right-hand side variables are the energy-sector variables (also in Gt C yr^{-1}) explained in Chapter 4, sections 3.1 and 3.2.

Next, the endogenous energy demand equation (given first in Chapter 3, section 2.1) connects the *endogenous energy demand* to the economic output, $Q(t)$, measured in 10^{12} US \$ yr^{-1} at market exchange rates and shown in bold type,

$$ED(t) = r_{ED:GDP_{1990}} \cdot \boldsymbol{Q(t)} \cdot SMOOTH\left(\left[{}^{AEP}/_{AEP_{1990}}\right]^{\rho_p}, 10\right)$$

Finally, water withdrawal and consumption for industrial purposes depend on electricity production, as explained in Davies (2007) and Davies and Simonovic (2008). The equations involved, based on Alcamo et al. (2003), are presented below, showing the new connection in bold type,

$W_{i_{desired}} = \boldsymbol{ElP_{TWh}} \cdot \omega_{MWh} - Q_{ww\ reuse_i}$, and
$C_{i_{desired}} = \boldsymbol{ElP_{TWh}} \cdot \kappa_{MWh}$

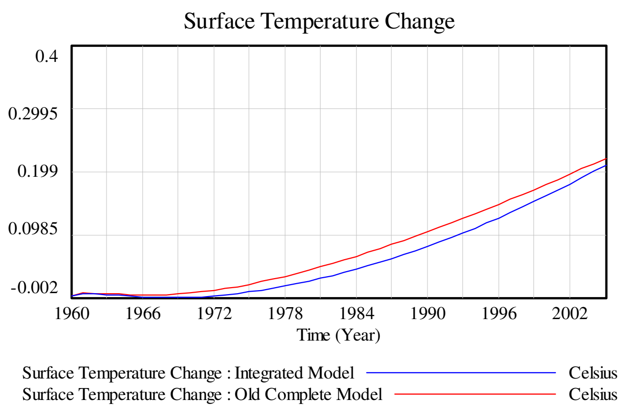
where $W_{i_{desired}}$ and $C_{i_{desired}}$ are, respectively, the desired withdrawal and consumption of surface waters for industrial purposes (in $km^3\ yr^{-1}$), ElP_{TWh} is the electricity production (in TWh yr^{-1}), ω_{MW} and κ_{MWh} are variables that represent the required surface water *withdrawals* and *consumption* per MWh of electricity produced (in $m^3\ MWh^{-1}$), and $Q_{ww\ reuse_i}$ is the amount of treated wastewater reused for industrial purposes (in $km^3\ yr^{-1}$). Unit conversion factors are not included in the equation.

3. Modelling Results from Integrated Model

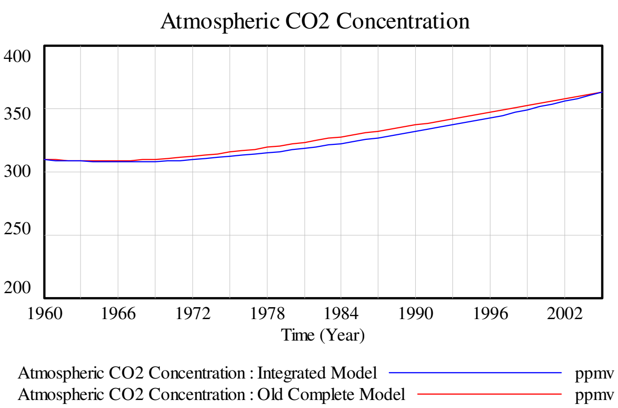
The results shown in this section are not intended to be exhaustive, but rather to show the general differences in model behaviour that result from the changes to the model structure described in the previous section. The simulation results focus on the key variables from several model sectors,

- Global temperature,
- Atmospheric carbon dioxide levels,
- Economic output,
- Renewable flow of surface water,
- Surface water withdrawals and consumption,
- Water stress, and
- Greenhouse gas emissions

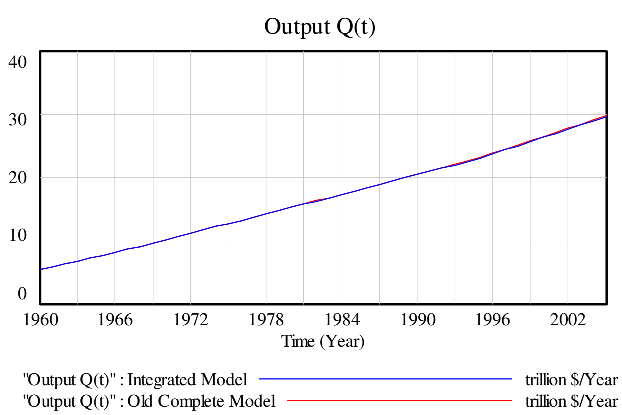
In the following graphs, the results marked "integrated model" come from the new version of the model that incorporates the energy sector, while the results from the "old complete model" are from the "base case" simulation using the older version of the model. All results are presented in FIG X, with the key variables depicted clearly stated below each graph.



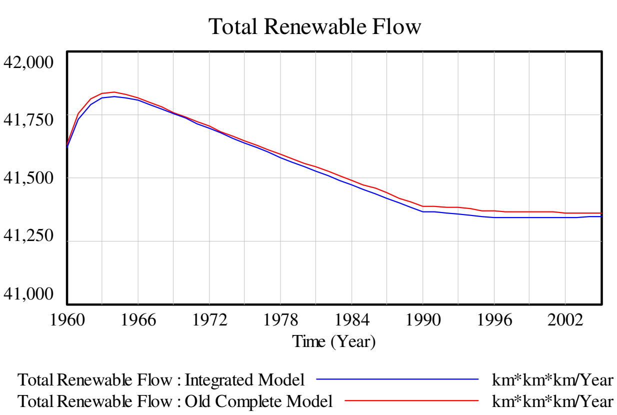
Average Global Temperature (Δ°C)



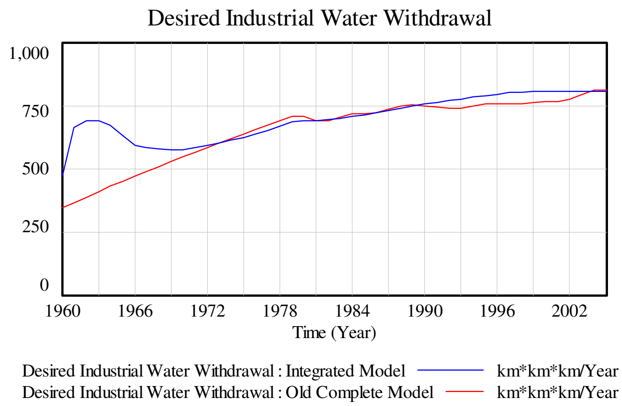
Atmospheric CO_2 Concentration (ppm)



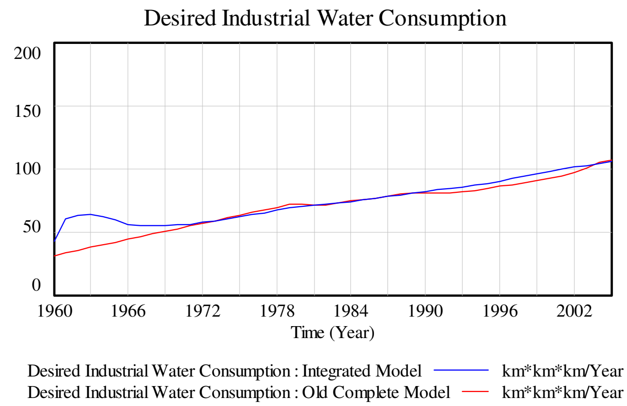
Global Economic Output (10^{12} US$ at MER)



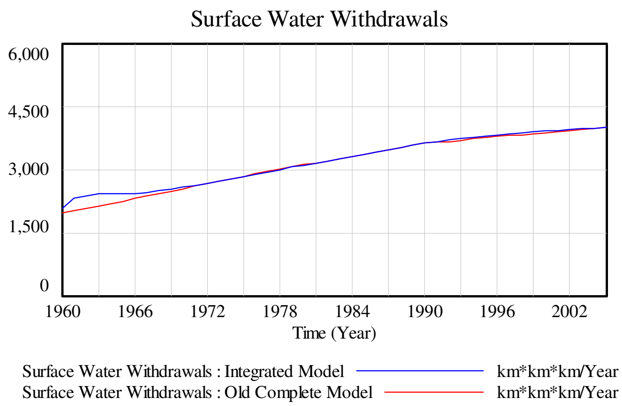
Total Renewable Flow (km^3 yr^{-1})



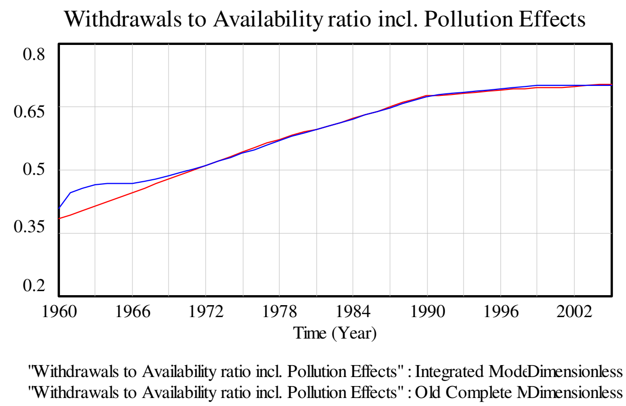
Industrial Water Withdrawals (km^3 yr^{-1})



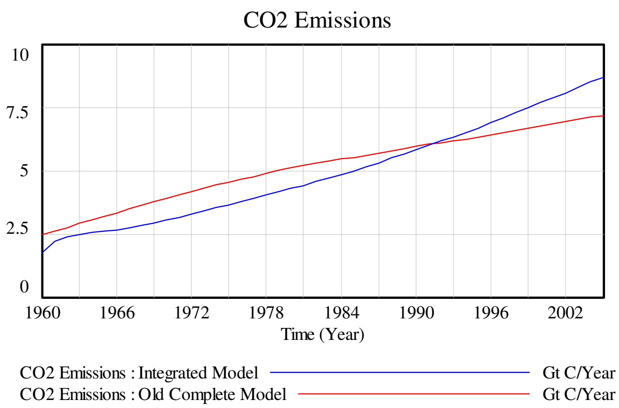
Industrial Water Consumption (km^3 yr^{-1})



Total Surface Water Withdrawals (km^3 yr^{-1})



Water Stress (-)



Total Industrial Emissions (Gt C yr^{-1})

Figure 76: Results from the incorporation of the energy sector into the full society-biosphere-climate model

Chapter Seven: Model Use and Capabilities

This chapter focuses on model use and improvement in the following areas: economic variables and processes, and model strengths and limitations (1), and key policy variables and their use in policy simulations (2).

1. Economic Improvements to Model

The economic elements of the model currently represent economic variables in a simplified fashion, and many equations serve as place-holders for a more complex economic treatment. However, the current approach gives results that match historical figures relatively closely, with simulated behaviour that is basically reasonable. Below is a description of the individual economic components of the model, followed by a listing of the major economic variables whose equations may require changes.

Investments can be made into both primary and secondary energy supply:

- Investment into *primary energy supply* (heat-energy, and fossil fuels for electricity production) depends on the profitability of the current supply. When energy extraction is profitable, some (variable) fraction of that profit is invested into new extraction capacity. When profits are small, minimal investment into new capacity occurs. When losses occur, a calculated proportion of the resource extraction capacity goes bankrupt and is removed from the resource-specific extraction capacity.
- Investment into *secondary energy supply* (electricity) increases based on the historical trend in capacity increases, and also serves to replace the retirement of current capacity. Excess electricity generation capacity does not go bankrupt, but if demand falls, excess capacity may not be replaced after its (eventual) retirement.

The **allocation of investments** depends on the energy type:

- Investments into *resource extraction* of the three primary fuels depend on relative costs of production, with the least expensive fuel receiving the most funding for expansion; however, to increase the realism of the simulation, fuels are weighted according to their relative convenience. Since the cheapest fuel may not be the most convenient, investment depends on both cost and usefulness.
- Investments into *electricity production* are allocated to the specific technologies available on the basis of total generation cost (*fixed* plus *variable* costs) of each technology.[87] Fixed costs vary over time as a result of technological change. Variable costs depend on the production costs of fossil fuels.

Note that the allocation algorithm used is a built-in function in Vensim that allows either exclusive investments (i.e. the lowest price option gets all the investment) or inclusive investment (investment funds are allocated relatively evenly). For more information, see Chapter 2, section 3.2.3.

[87] Future model versions must include changes in price for renewables (hydro, alternatives), since less accessible locations have higher capital costs and saturation effects reduce the efficiency of generation, and so on.

Energy prices vary over time based on the effects of depletion and the ability of energy supplies and production capacity to meet energy demands:

- Primary *energy prices* increase when demand rises quickly and extraction almost reaches its maximum; energy prices decrease when demand falls and capacity is left idle. Depletion effects increase production costs.
- Secondary *energy prices* have two components: average generation costs, and average variable costs. Decisions about electricity generation capacity expansions use the average generation cost of each electricity production technology, where the average generation cost is the annualized *capital costs* plus the annual *variable costs*. Once the chosen electricity production capacity is installed, decisions about capacity utilization depend on variable costs. Thus, oil-fired electricity plants may simply not be used when energy demand is low, for example, since oil is relatively expensive, while almost all the nuclear capacity is used because fissile material is relatively inexpensive.

The names, symbols, and descriptions of the key economic variables that may require equation updates are provided next. Note that the equations of all energy sector variables are listed in Appendix A, on page 141, along with a reference to the report section that describes each variable in greater detail.

- *Market Price*, MP_i, the market price of each fossil fuel (in \$ GJ^{-1}),
- *Production Cost*, PC_i, the cost to produce each unit of fossil fuel energy (in \$ GJ^{-1}),
- *Energy Profit*, $EP_{{profit}_i}$, the annual profit from the extraction of each fossil fuel (in \$ yr^{-1}),
- *Average Generation Cost*, GC_i, the average cost of producing one unit of electricity capacity through each technology type (in \$ kW^{-1} yr^{-1}). Its constituent elements are,
  - *Fixed Cost*, $\mathfrak{F}C_{\mathrm{i}}$, the fixed cost of electricity produced from each available technology (in \$ kW^{-1} yr^{-1}), which depends on the,
    - *Annual Capital Cost*, KC_i, the annualized cost of capital for each electricity production technology (in \$ kW^{-1} yr^{-1}),
  - *Variable Cost*, VC_i, the variable cost of electricity produced from each available technology (in \$ kW^{-1} yr^{-1}), which depends on the,
    - *Fuel Cost*, FC_i, the average fuel cost for each technology, including depletion (in \$ kW^{-1} yr^{-1}),
- *Electricity Capital Cost*, $KE_{{cost}_i}$, the cost of each additional unit of electricity production capacity (in \$ kW^{-1}),
- *Available Market-based Investment in Electricity*, Inv_{Market}, the total monetary value of funds invested in increasing the maximum electricity production capacity (in 10^9 \$ yr^{-1}),
- *Desired Investment in Electricity Capacity*, $\frac{dInv_{KEcap\_des_i}}{dt}$, the desired investment in the electricity production capacity of each available technology (in 10^9 \$ yr^{-1}), and,
- *Technology-specific Electricity Investment*, $\frac{dInv_{KEcap_i}}{dt}$, the amount of investment that each available electricity production technology receives (in 10^9 \$ yr^{-1}).

Other variables that are not specifically *economic* variables, but that are strongly affected by economic factors, may also require revision,

- *Proposed Expansion of Electricity Production Capacity*, $\frac{dKE_{cap_i}}{dt}$, the proposed expansion of electricity production capacity by available production technologies (in GW yr^{-1}), which is calculated using an allocation procedure that could be modified,
- *Electricity Production*, ElP_i, the electricity produced by each available electricity production technology (in GJ yr^{-1}), which is calculated using an allocation procedure that could be modified,
- *Net Energy Demand*, ED, the total of endogenous heat- plus electric-energy demand (in GJ yr^{-1}),
- *Heat*- or *Electric-energy Demand*, ED_i, the energy demand for either heat-energy or electric-energy sources (in GJ yr^{-1}), which is calculated using an allocation procedure that could be modified. The sum of $ED_{heat} + ED_{electricity}$ is ED, and,
- *Primary Energy Demand*, ED_{heat_i}, the quantity of heat-energy demanded from each fossil fuel-type (in GJ yr^{-1}), which is calculated using an allocation procedure that could be modified.

1.1 Limitations of the Current Economic Approach

As stated above, economic variables and decisions are represented very simply. *Investment funds* for electricity generation are prescribed and then allocated; therefore, total investment is dynamic only in the sense that it meets demand, which rises over time through economic development. *Price calculations* (both market prices and production costs) are very simple, and *demand* is represented in a simple fashion that does not adequately capture historical changes in behaviour. Further, the model is *myopic*, and so decisions are made on the basis of historical behaviour with no ability to adapt to anticipated changes until they arrive.

Details of the economic limitations of the model are provided in the following list.

- The determination of available funds for expansion of the maximum electricity production capacity is particularly simple: the demand for funds is always met.
- The allocation algorithm used for distributions of *investment funds* to individual heat-energy and electric-energy production capacity expansions (total coal, oil, and natural gas extraction capacities as well as coal-fired, oil-fired, nuclear, etc., electricity production capacity), and allotments of *capacity utilization* (how much of the total available capacity to use) is a built-in Vensim function and its operation is opaque. This opacity does not mean that the resulting behaviour is wrong, but it does mean that its causes are not specified.
- Price calculations use simple forms that function basically as place-holders for more complicated equations. Production costs change as a result of depletion effects. Market prices vary with the ratio of demand : extraction capacity, and depend on the production cost. These forms are suggested by the literature, but are generally provided there only in a qualitative form – I had to fill in the blanks. Therefore, modifications are probably necessary.
- The global energy demand is currently simulated through an approach developed for the COAL2 energy model. The approach is simple, and works reasonably, but more complex treatment is likely required. COAL2 ties energy demand to *income* and *price effects*: a 1% rise in GDP will cause a 1% rise in energy demand, and a 1% rise in price will cause a -0.28% rise in demand (after some delay).

- Economic output is not tied to energy supply/demand or prices. Thus, energy prices could rise or fall dramatically with no effect on the economic system. One option is to modify the Cobb-Douglas production function used for economic output to include energy as well as capital and labour.
- The base-year for economic measurement in the energy sector is not presently specified – my guess is that the capital cost calculations use a base year of roughly 2000, but the sources were not specific. EIA and IEA data sources tend to provide a base year, and I have included these units where possible in the model documentation.

However, despite the current economic limitations of the current model, the approach has strengths as well. In particular, the physical representations – resources, extraction capacity, electricity generation – are complete, easy to understand, and easy to modify. Importantly, they generate behaviour that approximates historical behaviour quite well. Furthermore, the decision-making elements of the model – investments, prices and costs, construction pipelines – approximate real-world behaviour, at least qualitatively.

Therefore, the basic informational framework of the energy sector is in place, and modifications of economic variables (and their calculations) should be possible within the provided framework.

2. KEY POLICY VARIABLES AND POLICY SIMULATIONS

Simulation models allow an investigation of "what if" questions, help to identify useful policies and practices, and improve understanding of modelled interconnections and their impacts on simulated and real-world behaviour. An initial, "base case" simulation serves as a basis of comparison for other simulations that differ from the base case because of changes imposed on model *constant* values or on exogenously-imposed *time-trends* of variables. These alternative simulations represent *alternative policies*, and may cause minor alterations in model behaviour in some cases, and substantial changes in others.[88]

Policies that can be simulated with minimal effort, and very minor modifications to the model structure, include:

1. Carbon taxes (increasing the costs of fossil fuels);
2. Energy subsidies (supporting one technology over another); and,
3. Planned electricity technology expansions (e.g. prescribed nuclear or hydroelectric expansions).

To simulate these policies, the focal variables should be,

1. *Market Price*, MP_i, the market price of each fossil fuel (in \$ GJ^{-1}),
2. *Electricity Capital Cost*, KE_{cost_i}, the cost of each additional unit of electricity production capacity (in \$ kW^{-1}),
3. *Prescribed " Nuclear and Hydro" Capacity Expansion*, or the *Market-based Investment by Electricity Production Technology*, $\frac{dInv_{KEcap_i}}{dt}$, which both represent the amount of investment that each electricity technology receives (in 10^9 \$ yr^{-1}).

Again, the equations of all energy sector variables are listed in Appendix A, on page 141, along with a reference to the report section that describes each variable in greater detail.

In terms of the actual approach, a multiplier could be added to the energy market price variable, MP_i, to simulate *carbon tax* effects. Using the multiplier, fossil fuel-based energy prices could be made to rise gradually over time, or even to rise instantaneously, depending on the policy approach chosen. The resulting rise in energy costs would affect both primary energy demand and capacity expansions, and technology-specific investments in additional electricity capacity.

Energy subsidies could be simulated by changing the profile of electricity capital costs, so that alternative-energy, nuclear, and hydroelectric capital costs decrease relative to fossil fuel-fired plants; changes to the profile could be made through a common multiplier that assigns a value of *x* to fossil fuel-fired plants and a value of *y* to non-fossil fuel plants, or individual values to each of the electricity production technologies. For example, the electricity capital cost equation could be changed to,

[88] The causes of changes can then be traced by identifying reasons for differences in the behaviour of model variables between simulation runs. Such causes include sensitivities built in to model equations, structural elements of the model (particularly in terms of integration effects), and combinational effects (calculation of one variable's value may depend on the value of another single variable, or on the combination of the values of many different variables). My thesis provides examples of *feedback-analysis*.

$KE_{cost_i} = \varphi_{subsidy_i} \cdot KE_{base\ cost_i}$

where KE_{cost_i} is the *new* capital cost of electricity production capacity (in \$ kW^{-1}), $\varphi_{subsidy_i}$ is the multiplier, set to $x_i > 1$ for *i* = coal, oil, natural gas, and $y = 1$ for *i* = alternatives, nuclear, and hydro, and $KE_{base\ cost_i}$ is the capital cost of electricity production capacity (in \$ kW^{-1}) until $t < t_{subsidy}$, after which time it becomes the *subsidy-free* cost of capital.

Finally, with slightly more effort, changes could be made to the *investment* structure to simulate "prescribed capacity expansions" in alternative energy, or in nuclear and hydroelectric power beyond the current cut-off of 2005 (after which time, nuclear and hydroelectric capacity expansions occur through market-based investments), or additional funds can be added directly to the market-based investment variable, so that more capacity will be installed after the construction delay.

Another approach towards implementing certain economic policies could rely on the *convenience factors* introduced in the endogenous energy demand equations. They could, for example, be used to represent effects like the expansion of an electric grid, or oversaturation of the same.

Other policies could also be simulated after additional model adjustments, including

- Carbon capture and storage technologies (which would require additional array subscripts, energy capital cost information and cost trends, and minor changes to the *emissions* sector);
- Preferential expansions in either heat-energy or electric-energy capacity (which would require a relatively small effort, and could be approached through the *convenience factors*);
- Simple representations of research and development efforts (such as those described in Chapter 5. Here, a relatively large effort would be required).

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Appendices

Appendix A: Energy Sector Equation Listing

A. Energy Sector Equations

This appendix provides a complete listing of all equations in the energy sector. Equations are organized according to the location of their introduction in the report. Therefore, full descriptions and explanations for the majority of the equations below are available in the body of the report; furthermore, the section and subsection numbers in that document are listed below to enable a quicker cross-reference.

Many of the equations use arrays. In general, subscript *i* indicates a fuel source selection, and takes values of *coal*, *oil*, and *natural gas* in heat-energy equations (Chapter 2, section 2); in electric-energy equations (Chapter 2, section 3), the set of subscript values also includes *nuclear*, *hydro*, and *alternative*. The subscript *j* is occasionally substituted for *i* when primary and secondary energy sources are used in close proximity, or in the same equation. Finally, in the case of *endogenous energy demand* (Chapter 3), the subscript *i* takes values of *heat* and *electricity*.

A.1 Key Variables

The number of equations below – almost seventy – necessitates some indication of relative importance. The variables that interact with other model sectors are, by equation number, for

Energy Resources:

- [1] The current energy source **reserves**, $R_i(t)$, of coal, oil, and natural gas (Mt, MB, and Tm^3),
- [2] The **resource depletion** (use) rate, R_{depl_i}, of coal, oil, and natural gas (Mt yr^{-1}, MB yr^{-1}, and Tm^3 yr^{-1}),
- [5] The total **production**, EP_i, of coal, oil, and natural gas (in GJ yr^{-1}),
- [9] The **maximum energy production capacity**, EP_{cap_i} (in GJ yr^{-1}),

Electricity Production:

- [22] The **capital cost** of electricity production capacity, $\boldsymbol{KE_{cost_i}}$ (in \$ kW^{-1}; changes are currently *prescribed* from historical figures),
- [24] The funds available for investment to increase the electricity production capacity, Inv_{Market} (in 10^9 \$ yr^{-1}),
- [40] The total electricity **production capacity**, KE_{cap_i}, for technology *i* (in GW),
- [43] The **electricity produced** by technology *i*, ElP_i (in GJ yr^{-1}),

Endogenous Energy Demand:

- [48] The **net energy demand**, ED (in GJ yr^{-1}),
- [49] The **heat-energy** and **electric-energy demand**, ED_i (in GJ yr^{-1}),

Greenhouse Gas Emissions:

- [64]-[66] **Carbon emissions** from coal, oil, and natural gas combustion (in Gt C yr^{-1}),
- [67]-[68] **Carbon emissions** from cement production and natural gas flaring (in Gt C yr^{-1}),

Other important variables include:

- [12]-[13] The **average market prices**, MP_i, and **production costs**, PC_i, of fossil fuels (in \$ GJ^{-1}),
- [21] The **average generation cost**, GC_i, for electricity production technology *i* (in \$ kW^{-1} yr^{-1}),
- [23] The desired *total* (i.e. technology-independent) change in electricity **generation capital**, $\frac{dKE_{cap\_des}}{dt}$ (in GW yr^{-1}),
- [27] The proposed expansion of electricity **production capacity**, $\frac{dKE_{cap_i}}{dt}$, for technology *i* (in GW yr^{-1}),
- [31] The amount of **investment** that technology *i* receives, $\frac{dInv_{KEcap_i}}{dt}$ (in 10^9 \$ yr^{-1}),
- [35] The total funds, IKE_{cap_i}, **invested** in the electricity production capacity of technology *i* (in 10^9 \$),
- [42] The maximum (i.e. **production at full capacity**) electricity production of technology *i*, ElP_{max_i} (in GJ yr^{-1}),
- [47] The fractional **capacity shares** of each electricity production technology, ς_i,
- [55]-[57] The **average energy**, **fossil fuel**, and **electricity prices**, AEP_i, AFC_{ff}, and AGC_{elec} (in \$ GJ^{-1}),
- [60] The quantity of **heat-energy demanded**, ED_{heat_i}, from fossil fuel-type *i* (in GJ yr^{-1}).

A.2 Energy Resources Equations (Chapter 2, Section 2.2)

The model currently simulates energy reserves of coal, crude oil, and natural gas, as well as additions through new reserve *discoveries*, and reductions of reserve levels through *extraction* and *fuel use* (2.2.1). Based on energy demand, it then adjusts reserve production capital and thus capacity (2.2.2).

1. Non-renewable Energy Reserves (Section 2.2.1)

The following equations replicate key behaviours in non-renewable energy resource (coal, oil, and natural gas) extraction: resource availability (equation [1]), resource discovery (prescribed time series), and resource depletion (equations [2]-[5]).

[1] $R_i(t) = \int \left(R_{disc_i} - R_{depl_i}\right) dt$

$R_i(t)$ is the current energy source reserve (in Mt, Mega-barrels (MB), or $Tm^3\ yr^{-1}$ for coal, oil, and natural gas, respectively),
R_{disc_i} is the resource discovery rate (in Mt yr^{-1}, MB yr^{-1}, or $Tm^3\ yr^{-1}$, respectively),
R_{depl_i} is the calculated resource depletion rate (same units).
Notes: Initial values are from section 2.1.1. Discoveries, R_{disc_i}, are prescribed.

[2] $R_{depl_i} = RE_{elec_i} + RE_{heat_i}$

RE_{elec_i} is the energy resource extraction for electricity production (same units as for R_{disc_i}),
RE_{heat_i} is for non-electric (heat) resource extraction (same units).
Note: Input to [1].

[3] $RE_{elec_i} = \left(\frac{1}{\varepsilon_i} + \lambda_i\right) \cdot \frac{ElP_i}{EC_i}$ (Section 2.2.1.1)

RE_{elec_i} is the resource extraction for electricity production (in Mt yr^{-1}, MB yr^{-1}, or $Tm^3\ yr^{-1}$),
ε_i is the efficiency of electricity production (40% for non-renewables; up to 100% for renewables[1]),
λ_i is the transmission and own-use losses of electricity production (15-25%),
ElP_i is the actual production of electricity from resource *i* (in GJ yr^{-1}; see equation [42]),
EC_i is the energy content of resource *i* (in GJ t^{-1}, MJ bbl^{-1}, or MJ m^{-3}; *constant value*)
Note: Input to [2].

[4] $RE_{heat_i} = EP_i / EC_i \cdot \alpha_i$ (Section 2.2.1.2)

EP_i is the actual primary energy production of fuel type *i* (in GJ yr^{-1}; see equation [5]),
$EC_i$is the energy content of fuel type *i*, (in GJ t^{-1}, MJ B^{-1}, or MJ m^{-3}),
α_i is a unit conversion factor (for ones to millions of units, and so on; *constant value*).
Note: Input to [2].

[5] $EP_i = MIN\left(ED_{heat_i}, EP_{cap_i}\right)$

EP_i is the actual primary energy production of fuel type *i* (in GJ yr^{-1})
ED_{heat_i} is the fuel-specific primary energy demand (in GJ yr^{-1}; currently set from *historical values* or calculated according to equation[60]),
EP_{cap_i} is the energy production capacity (in GJ yr^{-1}; see equation [9]),
MIN( ) ensures that energy production does not exceed capacity.
Note: Input to [4].

[1] The efficiency of non-renewable energy production should actually not be set to a constant value, since it has increased over time in the real-world. Changes in efficiency are a result of technological progress, and so are actually endogenous. For the sake of simplicity, they are treated as constant values here.

A.3 Energy Resource Extraction Capital (Section 2.2.2)

This section has two parts: 1) actual energy production capacity, and 2) investment into new production capacity.

1. Actual Energy Production Capacity: The Construction Pipeline (Section 2.2.1.1)

Fluctuations in energy demand over time and delays in capital construction mean that excess capacity is necessary. Identification of required capacity, its construction, subsequent addition to working capital, and eventual decommission constitutes a "pipeline" of four flows and two stocks (note similarity to electricity "pipeline" of section 3.3.1):

- Energy production capacity orders (flow 1, equation [6]; *inflow to stock 1*);
- Energy production capacity under construction (stock 1, equation [7]);
- Energy production capacity installation (flow 2, equation [8]; *outflow from stock 1, inflow to stock 2*);
- Energy production capacity (stock 2, equation [9]);
- Energy production capacity retirement (flow 3, equation [10]; *outflow from stock 2*);
- Energy production capacity bankruptcy (flow 4, equation [11]; *outflow from stock 2*).

[6] $EP_{cap\_orders_i} = MAX\left(EP_{des\_cap_i}, 0\right)$

$EP_{cap\_orders_i}$ is the energy production capacity orders (GJ yr^{-1}),
$EP_{des\_cap_i}$ is the desired energy production capacity addition (in GJ yr^{-1}; see equation [16]),
MAX( ) ensures non-negativity.

[7] $EP_{cap\_constr_i}(t) = \int \left(EP_{cap\_orders_i} - EP_{cap\_install_i}\right) dt$

$EP_{cap\_constr_i}(t)$ is the energy production capacity under construction (in GJ),
$EP_{cap\_install_i}$ is the energy production installed in the current time step (in GJ yr^{-1}).

[8] $EP_{cap\_install_i} = EP_{cap\_constr_i} / \tau_{constr_i}$

τ_{constr_i} is a "residence time", set to 3 years for all fossil fuel types.

[9] $EP_{cap_i}(t) = \int \left(EP_{cap\_install_i} - EP_{cap\_retire_i} - EP_{cap\_bankrupt_i}\right) dt$

EP_{cap_i} is the maximum energy production capacity of technology *i* (in GJ yr^{-1}),
$EP_{cap\_retire_i}$ is the energy production capacity retired in the current time period (in GJ yr^{-1}),
$EP_{cap\_bankrupt_i}$ is the energy production capacity lost to bankruptcy, in the case that overcapacity decreases market prices of resource *i* below production prices (in GJ yr^{-1}).

[10] $EP_{cap\_retire_i} = EP_{cap_i} / \tau_{cap\_lifetime_i}$

$\tau_{cap\_lifetime_i}$ is the "lifetime" of the production capacity for resource type *i*, set to 20 years.

[11] $EP_{cap\_bankrupt_i} = IF\ THEN\ ELSE\left(EP_{profit_i} < 0,\ \left|EP_{des\_cap_i}\right|,\ 0\right)$

EP_{profit_i} is the annual profit for the extraction of fuel *i* (in \$ yr^{-1}),

$EP_{des\_cap_i}$ is the desired energy production capacity addition (in GJ yr^{-1}; see equation [16]).

IF THEN ELSE(x, y, z) is a Vensim function/logical construction that checks the truth of the condition *x*, and then sets the LHS to value *y* if true, and to *z* if false.

2. Investment in Resource Extraction Capacity (Section 2.2.2.2)

This subsection provides equations for calculating investment in additional extraction capacity. Investment in new extractive capacity depends on its profitability, which depends in turn on the difference between market prices for energy resources and their production costs, and on the amounts of resources extracted. I assume here that production costs are relatively stable compared with market costs.

[12] $MP_i = \mu_i \cdot PC_i \cdot \left(\frac{ED_i}{EP_{cap_i}}\right)$

MP_i is the market price for fossil fuel *i* (in \$ GJ^{-1}),

PP_i is its production cost (in \$ GJ^{-1}),

μ_i is the transportation and storage adjustment (currently set to 1.2),

ED_i is the energy demand (in GJ yr^{-1}; currently set from *historical values*),

EP_{cap_i} is the maximum energy resource extraction rate (in GJ yr^{-1}; see equation [9]).

[13] $PC_i = fc_i(0) \cdot \left(\frac{R_i}{R_i(0)}\right)^{\rho}$

PC_i is the production cost for fuel *i* (in \$ GJ^{-1}),

$fc_i(0)$ is the initial fuel cost, neglecting depletion (in \$ GJ^{-1}; lower-case characters used to avoid same symbol as in equation [19]),

ρ is a resource coefficient (set to -0.4)

The last bracket is the depletion effect (see equation [1] and 4.1.2).

[14] $EP_{profit_i} = (MP_i - PC_i) \cdot EP_i$

EP_{profit_i} is the annual profit for the extraction of fuel *i* (in \$ yr^{-1}),

$MP_i - PC_i$ is the difference between market and production prices (\$ GJ^{-1}),

EP_i is the actual energy production (in GJ yr^{-1}; see equation [5]).

Investments into additional energy resource extraction capacity are made according to the potential profitability of that additional capacity – a Vensim function, *forecast( )*, is used here.

[15] $MP_{forecast_i} = FORECAST(MP_i, 10, 5)$

$MP_{forecast_i}$ is the market price of fuel *i* (in \$ GJ^{-1}) forecast 5 years (*third term* in equation) into the future based on 10 years (*second term* in equation) of market price data.

[16] $EP_{des\_cap_i} = \lambda_{MP\_lookup} \cdot EP_{profit_i}$

$EP_{des\_cap_i}$ is the desired energy production capacity addition (in GJ yr^{-1}),

λ_{MP_lookup} is a lookup table that transforms the ratio of current to forecast market prices, $MP_{forecast}/MP_i$ into a multiplier value. When $MP_{forecast}/MP_i > 1$, investment will occur at its maximum; when $MP_{forecast}/MP_i < 1$, investment will fall relative to its possible maximum. λ_{MP_lookup} values are given in Table A-1. Note that these values are placeholders only, and can therefore be updated from available data sources.

Table A-1: Lookup table for investment multiplier values

$MP_{forecast}/MP_i$	0.6	0.9	1.0	1.5	2.5
λ_{MP_lookup}	0.1	0.8	0.9	1	1

Note: When positive, $EP_{des\_cap_i}$ becomes the production capacity orders (in GJ yr^{-1}), $EP_{cap\_orders_i}$; when negative, it becomes the amount of extraction capacity lost to bankruptcy, $EP_{cap\_bankrupt_i}$.

A.4 Electricity Production (Chapter 2, Section 3)

The starting point of electricity production is the modelling of energy resource extraction and use for electricity production: the primary energy supply (section 2.2). Investment in electricity production capacity depends on electricity prices (section 3.1; first sub-section below), and consequently changes the mix of electricity production options (section 3.2; second subsection below), fuels required, efficiency of production (technology), and energy-generation prices. Electricity production prices affect, in turn, the capacity utilization by production-technology (section 3.3; third subsection below) – whether coal-fired, oil-fired, nuclear, or other – and the technological mix in the longer term.

1. Electricity Pricing: Screening Curve (Section 3.1.3)

Electricity capital- and fuel-pricing is used to determine relative investments into different types of electricity production capital, and for decisions about capital operation (how much technology-specific capacity to use). One option for capital pricing is a *screening curve* approach, which has five main components (Shaalan, 2001):

6. Fixed annual costs (capital costs; equation [17]);
7. Fixed operation and maintenance costs (prescribed values, based on *historical data*);
8. Cost per year at capacity factor of zero (fixed capital plus O&M costs; equation [18]);
9. Fuel costs (equation [19]); and,
10. Variable operation and maintenance costs (equation [20]).

[17] $KC_i = (r + 1/\tau_i) \cdot KE_{cost_i}$

KC_i is the annualized cost of capital of electricity production technology *i* (in \$ kW^{-1} yr^{-1}),

r is the interest rate (currently prescribed as 6%),

τ_i is the capital lifetime (also prescribed),

KE_{cost_i} is the electricity capital cost (in \$ kW^{-1}; see equation [22]),

[18] $\mathfrak{F}C_{\mathrm{i}} = KC_i + OM_{fix_i}$

$\mathfrak{F}C_{\mathrm{i}}$ is the fixed cost for electricity produced using technology *i* (in \$ kW^{-1} yr^{-1}),
OM_{fix_i} is the fixed operation and maintenance cost (in \$ kW^{-1} yr^{-1}).

[19] $FC_i = h/yr \cdot \left(fc_i(0) \cdot \left(\frac{R_i}{R_i(0)} \right)^{\rho} \right)$

FC_i is the average fuel cost for technology *i*, including depletion (in \$ kW^{-1} yr^{-1}),
h/yr is a capacity factor: the number of hours per year in operation (set to 8760 h/yr, or 100% capacity),
$fc_i(0)$ is the initial fuel cost, neglecting depletion (in \$ kW^{-1} h^{-1}),
ρ is a resource coefficient (set to -0.4)
The last bracket is the depletion effect (see equation [1]).

[20] $VC_i = FC_i + h/yr \cdot \left(OM_{var_i}\right)$

VC_i is the variable cost for technology *i* (in \$ kW^{-1} yr^{-1}),
FC_i is the average fuel cost, including depletion (in \$ kW^{-1} yr^{-1}, see equation [19])
h/yr is a capacity factor (set to 8760 h/yr),
OM_{var_i} is the variable operation and maintenance cost (in \$ kWh^{-1}; prescribed from *historical data* in Shaalan, 2001).

[21] $GC_i = \mathfrak{F}C_i + VC_i$

GC_i is the average generation cost for electricity production technology *i* (in \$ kW^{-1} yr^{-1}),
$\mathfrak{F}C_{\mathrm{i}}$ is the fixed cost for electricity produced using technology *i* (in \$ kW^{-1} yr^{-1}; see equation [18]),
VC_i is the variable cost for technology *i* (in \$ kW^{-1} yr^{-1}; see equation [20]).

2. Electricity Capital Costs (Section 3.1.4)

The “electricity capital cost” stock can change, through its flows:

[22] $KE_{cost_i}(t) = \int \left(KE_{cost\uparrow_i} - KE_{cost\downarrow_i} \right)$

KE_{cost_i} is the cost of electricity production capacity (in \$ kW^{-1}),
$KE_{cost\uparrow_i}$ and $KE_{cost\downarrow_i}$ are, respectively, the increase or decrease in the capital cost of technology *i* over time. These values are currently *prescribed* from historical data.[2]

3. Investment Sums for New Electricity Production Capacity (Section 3.2)

Investment has two components: a desired electricity production level, and desired electricity-production technologies. In terms of desired production, investment occurs both to meet the projected need and to replace the retired capacity. For investment to exceed the level required to replace retired electricity-production capital, there must be some anticipation of future electricity needs, and the requirements for investable funds must be determined. Of course, the retired capacity

[2] However, they can change because of cost increases from increased regulation, changes in policy, or materials shortages, for example, or because of cost decreases from policy or regulatory changes and, more importantly from a modelling viewpoint, from technological change.

need not be replaced with exactly the same generation technology, and new investment will be allocated to the most suitable – i.e. least-cost, generally-speaking – generation technology.

3.1 Anticipation of Future Needs (Section 3.2.1)

[23] $\frac{dKE_{cap\_des}}{dt} = TREND(EO, \tau_{EO}) \cdot KE_{cap} + \sum_i KE_{cap\_retired_i}$

$\frac{dKE_{cap\_des}}{dt}$ is the desired *total* (i.e. technology-independent) change in electricity generation capital (in GW yr^{-1}),
EO is the total electricity orders (in GJ yr^{-1}; currently prescribed from *historical data*),
τ_{EO} is the number of years to use in determining the *trend* in electricity orders, EO, currently set to 5 years,
KE_{cap} is the total installed electricity capacity (in GW),
$KE_{cap\_retired_i}$ is the generation capacity, of technology type *i*, retired in the current year (in GW yr^{-1}).
TREND( ) is a Vensim function that provides a very simple, fractional rate of change for a variable – in this case, *EO*, the energy orders – and that only works for positive trends.

3.2 Determination of Invested Sum (Section 3.2.2)

Although the investment funds necessary to build all of the desired electricity production capital may not be available in reality, the current approach is to calculate just such a sum – in other words, all desired capital is built. The "build-all" approach is intended as a place-holder for a more realistic treatment to be implemented at a later date. An additional assumption here is that dKE_{cap_des}/dt represents the amount of capacity to be added through a market-based allocation, rather than as a result of prescribed increases in capacity (nuclear and hydroelectric).[3]

[24] $Inv_{Market} = \frac{dKE_{cap\_des}}{dt} \cdot KE_{avg\_cost}$

Inv_{Market} is the total monetary value of funds invested in increasing the maximum electricity production capacity (in 10^9 \$ yr^{-1}),
dKE_{cap_des}/dt is the desired change in electricity production capital (in GW yr^{-1}; see equation [23]),
KE_{avg_cost} is the average cost of electricity capital (in \$ kW^{-1}).
Clearly, some unit conversion is required.

[25] $KE_{avg\_cost} = \sum_{\forall\, i} \varsigma_i \cdot KE_{cost_i}$

KE_{avg_cost} is the average cost of electricity capital (in \$ kW^{-1}),
ς_i is the market share of technology *i* (*fractional*; see equation [47]),
KE_{cost_i} is the capital cost for electricity production technology *i* (in \$ kW^{-1}; see equation [22]).

3.3 Allocation of Investment Funds (Section 3.2.3)

Investment funds are allocated among the electricity production technologies using a built-in Vensim function, called *ALLOCATE BY PRIORITY( )*. The function is described in some detail in section 3.2.3 of

[3] See the body of the report for a discussion of the implications of this assumption.

Chapter 2. The key point, however, is that the function allocates a scarce resource to *x* requesters (in this case, six) by a selected allocation priority (in this case, generation cost, equation [21]). The allocation can be quite even – so that each requester receives a value equal, or nearly equal, to the value received by all other requesters – or quite uneven – so that a 'winner' takes all.

The allocation procedure has the following steps:

4. Identification of the optimal electricity production capacities by the available electricity generation technologies (in this case, coal-fired, oil-fired, natural gas-fired, and alternative sources[4]; equations [26]-[29]);
5. Allocation of available investment funds to the desired electricity production technologies (equations [30] and [31]);
6. Entering of the investment funds into the construction pipeline, so that the desired production capacity becomes available, after the construction delay.

Steps one and two both use the *allocate by priority* function.

Step 1:

[26] $\frac{dKE_{cap\_des_i}}{dt} = IF\ THEN\ ELSE\left(\frac{dKE_{cap\_des}}{dt} \leq KE_{cap_i}, \frac{dKE_{cap\_des}}{dt}, \frac{KE_{cap_i}}{3}\right)$

$\frac{dKE_{cap\_des_i}}{dt}$ is the *requested* additional capacity for technology *i* (in GW yr^{-1}),

$\frac{dKE_{cap\_des}}{dt}$ is the desired change in *total* electricity production capacity (in GW yr^{-1}; see equation [23]),

KE_{cap_i} is the currently installed electricity production capacity for technology *i* (in GW),
The effect of the equation is to restrict the maximum increase in the capacity of technology *i* to one-third[5] its current value, so that the capacity rises slowly.

[27] $\frac{dKE_{cap_i}}{dt} = ALLOCATE\ BY\ PRIORITY\left(\frac{dKE_{cap\_des_i}}{dt}, p_i, Hydro, w_{constr}, \frac{dKE_{cap\_des}}{dt}\right)$

$\frac{dKE_{cap_i}}{dt}$ is the proposed expansion of electricity production capacity for technology *i* (in GW yr^{-1}),
$\frac{dKE_{cap\_des_i}}{dt}$ is the *requested* additional capacity for technology *i* (in GW yr^{-1}; see equation [26]),

p_i is the *priority* (see equation [28]),
$Hydro$ is the last element of the *electricity sources* array (see section 3.2.3),
w_{constr} is the *width* (see equation [29]),
$\frac{dKE_{cap\_des}}{dt}$ is the desired change in *total* electricity production capacity (in GW yr^{-1}; see equation [23]).

[4] Nuclear and hydroelectric production capacities are prescribed. This is a common approach in energy-economy models.
[5] The value of one-third is chosen because it provides a relatively close match to historical growth patterns. The sort of approach taken here, allowing a growth per year of only 1/3 the current production capacity, is chosen for simplicity; however, as the model increases in complexity, a fixed-factor or similar approach may prove superior.

[28] $p_i = 1/GC_i$

p_i is the *priority* (used in the *allocate by priority* function) for electricity production technology *i.* Technologies with lower generation costs are preferable to those with higher costs per kWh.

[29] $w_{constr} = MAX(p_i)$ or $w_{constr} = VMAX(p[i!])$

w_{constr} is the *width* (used in the *allocate by priority* function).
The left-hand equation is a logical form, while the right-hand equation follows Vensim syntax. This calculation *weights* the allocation of electricity production capacity among technologies *i*.

Step 2:

[30] $\frac{dInv_{KEcap\_des_i}}{dt} = (1 + r_i)^{\tau_{kc}} \cdot KE_{cost_i} \cdot \frac{dKE_{cap_i}}{dt}$

$\frac{dInv_{KEcap\_des_i}}{dt}$ is the desired investment in the electricity production capacity of technology *i* (in 10^9 \$ yr^{-1}),
r_i is the fractional interest rate (set to 0.06; same as in equation [17]),
τ_{kc} is the construction period (set to 8, 8, 8, 4, 10, 10 years for coal, oil, natural gas-fired, alternatives, nuclear, and hydro, respectively),
KE_{cost_i} is the cost of electricity production capacity (in \$ kW^{-1}; see equation [22]),
$\frac{dKE_{cap_i}}{dt}$ is the proposed expansion of electricity production capacity for technology *i* (in GW yr^{-1}; see equation [27]).

[31] $\frac{dInv_{KEcap_i}}{dt} = ALLOCATE\ BY\ PRIORITY\left(\frac{dInv_{KEcap\_des_i}}{dt}, p_i, Hydro, w_{constr}, Inv_{Market}\right)$

$\frac{dInv_{KEcap_i}}{dt}$ is the amount of investment that technology *i* receives (in 10^9 \$ yr^{-1}),
Inv_{Market} is the availability of market-based – i.e. non-nuclear, non-hydroelectric – investment funds for the year (in 10^9 \$ yr^{-1}; see equation [24]).

Step 3 (Section 3.2.4):

For i = 1, 2, 3, 4, $\frac{dInv_{KEcap_i}}{dt}$ is determined through the *allocate by priority* function; for *i* = 5, 6, $\frac{dInv_{KEcap_i}}{dt}$ is prescribed according to historical values (see section 3.2.5). *Step 3* is analogous to the construction pipeline of section 2.2.2.1 (equations [6]-[11]).

[32] $IKE_{cap\_orders_i} = \frac{dInv_{KEcap_i}}{dt}$

$IKE_{cap\_orders_i}$ is the amount of investment that technology *i* receives (in 10^9 \$ yr^{-1}; see equation [30]).

[33] $IKE_{cap\_constr_i}(t) = \int \left(IKE_{cap\_orders_i} - IKE_{cap\_install_i}\right) dt$

$IKE_{cap\_constr_i}(t)$ is the total investment in construction of electricity production (in 10^9 \$),
$IKE_{cap\_install_i}$ is the value of electricity production installed in the current period (in 10^9 \$ yr^{-1}).

[34] $IKE_{cap\_install_i} = IKE_{cap\_constr_i}/\tau_{kc_i}$

τ_{kc_i} is a "residence time" (see equation [30]).

[35] $IKE_{cap_i}(t) = \int \left(IKE_{cap\_install_i} - IKE_{cap\_retire_i}\right) dt$

IKE_{cap_i} is the total funds invested in electricity production capacity (in 10^9 \$),

$IKE_{cap\_retire_i}$ is the value of the electricity production capacity retired in the current period (in 10^9 \$ yr^{-1}).

[36] $IKE_{cap\_retire_i} = IKE_{cap_i}/\tau_{k_i}$

τ_{k_i} is the "lifetime" of the electricity production capacity for technology *i*, (set to 20 years for all technologies except hydro, set to 50 years).

4. Electricity Production (Section 3.3)

Electricity production capacity is not all used – in fact, load factors for certain electricity production capital can be relatively low. The maximum production capacity comes directly from investment, and its degree of utilization depends on variable costs.

4.1 Maximum Electricity-production Capacity (Section 3.3.1)

The electricity production capacity plays a crucial role in the model, because it determines the maximum amount of electricity that can be produced in each year, regardless of demand. The modelled set of stocks and flows constitutes a "construction pipeline" and so is analogous to equations [6]-[11] and [32]-[36]. It consists of capacity under construction (stock one), and operational electricity production capacity (stock 2), as well as the flows that connect them:

[37] $KE_{cap\_orders_i} = \frac{dInv_{KEcap_i}}{dt}/KE_{cost_i}$

$KE_{cap\_orders_i}$ is the electricity production capacity under construction (in GW yr^{-1}),

$\frac{dInv_{KEcap_i}}{dt}$ is the amount of investment that technology *i* receives (in 10^9 \$ yr^{-1}; see equation [31]),

KE_{cost_i} is the cost of electricity production capacity (in \$ kW^{-1}; see equation [22]),

Note: necessary unit conversions not shown.

[38] $KE_{cap\_constr_i}(t) = \int \left(KE_{cap\_orders_i} - KE_{cap\_install_i}\right) dt$

$KE_{cap\_constr_i}(t)$ is the amount of electricity production currently under construction (in GW),

$KE_{cap\_install_i}$ is the electricity production capacity installed in the current period (in GW yr^{-1}).

[39] $KE_{cap\_install_i} = KE_{cap\_constr_i}/\tau_{kc_i}$

τ_{kc_i} is a "residence time" (see equation [30]).

[40] $KE_{cap_i}(t) = \int \left(KE_{cap\_install_i} - KE_{cap\_retire_i}\right) dt$

KE_{cap_i} is the maximum electricity production capacity for technology *i* (in GW),

$KE_{cap\_retire_i}$ is the electricity production capacity retired in the current period (in GW yr^{-1}).

[41] $KE_{cap\_retire_i} = KE_{cap_i}/\tau_{k_i}$

τ_{k_i} is the "lifetime" of the electricity production capacity for technology *i*, (set to 20 years for all technologies except hydro, set to 50 years).

4.2 Actual Electricity Production by Technology (Section 3.3.2)

While the previous section focuses on the modelling of maximum electricity production capacity, this section explains how actual generation is determined. Hoogwijk (2004) explains that the *operational strategy* determines how much of the installed capacity is used and when, based on the *variable costs*. The approach taken here is to use the *allocate by priority* algorithm, again.

[42] $ElP_{max_i} = \kappa_{max_i} \cdot h/yr \cdot KE_{cap_i}$

ElP_{max_i} is the maximum (i.e. production at full capacity) electricity production (in GJ yr^{-1}),

κ_{max_i} is the technology-specific maximum operating capacity, (set to 90% except for both alternative and hydroelectric energy, which are set to 50% and 45%, respectively),

KE_{cap_i} is the total electricity production capacity (in GW; see equation [40]),

A conversion factor for GWh to GJ is necessary, and equals 3600 (1 GWh = 3600 GJ)

Note: The maximum operating capacities for alternative and hydroelectric energies are perhaps unreasonably low numbers[6]; however, the rationale is that weather or ecology places restrictions on “fuel” availability

[43] $ElP_i = ALLOCATE\ BY\ PRIORITY \left(ElP_{max_i}, p_{prod_i}, Hydro, w_{prod}, EO_{elec}\right)$

ElP_i is the electricity produced by technology *i* (in GJ yr^{-1}),

p_{prod_i} is the *priority* of production technology *i* (see equation [44]),

w_{prod} is the *width* of the allocation algorithm (see equation [45]),

EO_{elec} is the total amount of electricity ordered in the current period, based on *historical data* (in GJ yr^{-1}).

[44] $p_{prod_i} = 1/VC_{kWh_i}$

p_{prod_i} is the electricity production priority of request *i*,

VC_{kWh_i} is the variable cost of production for technology *i* (in \$ kWh^{-1}, see equation [46]).

[6] Although, the electricity generation capacity required to satisfy peak loads, plus some margin of safety (typically 20%) is significantly greater than average generation rates. Indeed, the *annual capacity utilization factor* has remained near 50-55% over most of the history of the electric utility industry (Naill, 1977: 89)

[45] $w_{prod} = MAX\left(p_{prod_i}\right)$ or $w_{prod} = VMAX(p_{prod}[i!])$

$w_{prod} = MIN\left(p_{prod_i}\right)$ or $w_{prod} = VMIN(p_{prod}[i!])$

w_{prod} is the *width* of the allocation algorithm,

The left-hand equation is a logical form, while the right-hand equation follows Vensim syntax.

This calculation *weights* the allocation of electricity production among technologies *i*.

Explanation: The two easiest approaches for *width* are to assign either the maximum priority value or the minimum priority value. The maximum priority approach would allocate electricity production most evenly across all generating capacity, while the minimum priority would allocate sequentially, from highest priority to lowest priority.[7]

[46] $VC_{kWh_i} = FC_i/\varepsilon_i + OM_{var_i}$

VC_{kWh_i} is the variable cost of production for technology *i* (in \$ kWh^{-1}),

FC_i is the total fuel cost for technology *i*, including depletion (in \$ kW^{-1} yr^{-1}; see equation [19]),

ε_i is the efficiency of electricity production (see equation *[3]*),

OM_{var_i} is the variable operation and maintenance cost (see equation [20]),

A conversion factor of 3.6/1000 converts the fuel cost, FC_i, from \$ kW^{-1} yr^{-1} to \$ kWh^{-1}.

4.3 Market Share (Section 3.3.3)

Market share values are important in determining average electricity- and electricity-capital prices.

[47] $\varsigma_i = {KE_{cap_i}}\Big/{\sum_{\forall i} KE_{cap_i}}$

ς_i is the market share of electricity technology type *i* (Fractional),

KE_{cap_i} is the maximum electricity production capacity for technology *i* (in GW; see equation [40]).

A.5 Endogenous Energy Demand (Chapter 3, Section 0)

Energy demand in the model can be represented endogenously, so that changes in certain parts of the model causes changes in the simulated energy demand, or exogenously, through the prescription of historical values, in which case model behaviour has no effect on the energy demand.

Net Energy Demand (Section 2.1)

The equations here relate to *endogenous* energy demand. Changes in *net energy demand* occur as a result of changes in GDP and the average energy price, according to an *income effect* and a *price effect*. The net energy demand represents the total quantity of energy demanded for consumptive purposes, and so includes both heat-energy and electric-energy demands.

[7] There are reasonable grounds for either choice. Use of the maximum width approach would guarantee that all installed capital would see some operating time, and represent the dispersed nature of global electricity production capacity more realistically (many areas have only one generation option, and so each area will use the technology it has). The minimum width approach would cause variable cost differences to play the driving role in allocation decisions, but may overemphasize small differences in variable costs.

[48] $ED = r_{ED:GDP_{1990}} \cdot Q(t) \cdot SMOOTH\left(\left[{}^{AEP}/_{AEP_{1990}}\right]^{\rho_p}, 10\right)$

ED is the net energy demand, or the total of endogenous heat- plus electric-energy demand (in GJ yr^{-1}),
$r_{ED:GDP_{1990}}$ is the ratio of energy use to GDP in 1990 (in GJ $\$^{-1}$, set to 0.014 GJ $\$^{-1}$),
$Q(t)$ is the economic output from the economic sector of the full model (in 10^{12} 1990 US \$ at MER),
AEP is the average energy price (in \$ GJ^{-1}; see equation [55]),
AEP_{1990} is the "normal" energy price, using 1990 as a base year (in \$ GJ^{-1}, and set to \$4.5 GJ^{-1}),
ρ_p is the price elasticity (set to -0.28),
$SMOOTH(\,)$ averages the left-hand quantity over the right-hand parameter value (10 years).

Heat- and Electric-energy Demand (Section 2.2)

Because the model differentiates between heat-energy and electric-energy demand, the net energy demand (equation [48]) must be divided into its heat- and electric-energy components through a call to the *allocate by priority* algorithm.

[49] $ED_i = ALLOCATE\ BY\ PRIORITY\left(ED_{des_i}, p_{demand_i}, electricity, w_{demand}, ED\right)$

ED_i is the energy demand for either heat-energy or electric-energy sources (in GJ yr^{-1}). The sum of $ED_{heat} + ED_{electricity}$ is ED (see equation [48]),
ED_{des_i} is the desired heat-energy or electric-energy production (in GJ yr^{-1}; see equations [50] and [51]),
p_{demand_i} is the *demand priority*, or the relative attractiveness of heat-energy and electric-energy, with higher values being more attractive (see equations [52] and [53]),
$electricity$ is the last member of the array, and is a parameter in the *allocate by priority* algorithm,
w_{demand} is the *width* variable in the *allocate by priority* algorithm (see equation [54]),
ED is the net energy demand, or the total of endogenous heat- plus electric-energy demand (in GJ yr^{-1}; see equation [48]).

[50] $ED_{des_{heat}} = \sum_{\forall i} \varphi_{reserve_i} \cdot EP_{cap_i}$

$ED_{des_{heat}}$ is the desired heat-energy production (in GJ yr^{-1}),
$\varphi_{reserve_i}$ is a binary flag (0, 1) that indicates whether fossil fuel reserves of type *i* are non-zero (i.e. are not exhausted), and is also used in equation [61],
EP_{cap_i} is the maximum primary energy resource extraction for fuel type *i* (in GJ yr^{-1}).
Note: the subscript *i* represents primary production from coal, oil, and natural gas resources.

[51] $ED_{des_{electricity}} = \sum_{\forall j} ElP_{max_j}$

$ED_{des_{electricity}}$ is the desired electric-energy production (in GJ yr^{-1}),
ElP_{max_j} is the maximum electricity production per year for electricity production technology *j* (in GJ yr^{-1}).

Note: the subscript *j* represents secondary production from coal-fired, oil-fired, natural gas-fired, alternative, nuclear, and hydroelectric power plants.

[52] $p_{demand_{heat}} = SMOOTH\left(\varphi_{convenience_{heat}} \cdot \frac{1}{AFC_{ff}}, 10\right)$

$p_{demand_{heat}}$ is the relative attractiveness of heat-energy, as compared with the attractiveness of electric-energy (equation [53]),
$\varphi_{convenience_{heat}}$ is a multiplier that accounts for the relative *attractiveness* of heat-energy and electric-energy (set to 1),
AFC_{ff} is the average cost of fossil fuels (in \$ GJ^{-1}; see equation [56]),
$SMOOTH(\,)$ averages the left-hand quantity over the right-hand parameter value (10 years).

[53] $p_{demand_{electricity}} = SMOOTH\left(\varphi_{convenience_{elec}} \cdot \frac{1}{AGC_{elec}}, 10\right)$

$p_{demand_{electricity}}$ is the relative attractiveness of electric-energy, as compared with the attractiveness of heat-energy (equation [52]),
$\varphi_{convenience_{elec}}$ is a multiplier that accounts for the relative *attractiveness* of heat-energy and electric-energy (set to 1.25),
AGC_{elec} is the average electricity production cost (in \$ GJ^{-1}; see equation [57]),
$SMOOTH(\,)$ averages the left-hand quantity over the right-hand parameter value (10 years).

[54] $w_{demand} = MAX\left(p_{demand_i}\right)$ or $w_{demand} = VMAX(p_{demand}[i!])$

w_{demand} is the *width* variable in the *allocate by priority* algorithm.
The left-hand equation is a logical form, while the right-hand equation follows Vensim syntax.
This calculation *weights* the allocation of energy demand among energy types *i* (heat and electricity) – see also the notes for equation [45].

1. Average Energy Prices (Section 2.2.1)

Average prices play a key role in the energy demand sector, since they determine both the change in overall energy demand, and the changes in relative heat and electricity demands. Average price equations are provided here for all energy sources (primary and secondary), fossil fuels (primary), and electricity (secondary energy).

[55] $AEP = \frac{AFC_{ff} + AGC_{elec}}{EP_T}$

AEP is the average energy price (in \$ GJ^{-1}), a production-weighted price that accounts for both primary and secondary energy,
AFC_{ff} is the average cost of fossil fuels (in \$ GJ^{-1}),
AGC_{elec} is the average electricity production cost (in \$ GJ^{-1}),
EP_T is the total primary and secondary energy production (in GJ; see equation [58]).

[56] $AFC_{ff} = \frac{\sum_i MP_i \cdot EP_i}{\sum_i EP_i}$

AFC_{ff} is the average cost of fossil fuels (in \$ GJ^{-1}),
MP_i is the market price for energy resource *i* (in \$ GJ^{-1}; see equation [12]),
EP_i is the production of primary energy resource *i* (in GJ; see equation [5]).
Note: The subscript *i* represents primary energy sources, coal, oil, and natural gas.

[57] $AGC_{elec} = \sum_j GC_{GJ_j} \cdot \varsigma_j$

AGC_{elec} is the average electricity production cost (in \$ GJ^{-1}),
GC_{GJ_j} is the electricity generation cost for technology *j* (in \$ GJ^{-1}; see equation [59]),
ς_j is the market share of electricity production technology *i* (*fractional*; see equation [47]).
Note: The subscript *j* represents electric energy sources.

[58] $EP_T = \sum_i EP_i + \sum_j ElP_j$

EP_T is the total primary and secondary energy production (in GJ),
EP_i is the production of primary energy resource *i* (in GJ; see equation [5]),
ElP_j is the electricity produced by technology *j* (in GJ; see equation [43]).

[59] $GC_{GJ_j} = GC_j \cdot \frac{1}{h/yr} \cdot \frac{1}{0.0036}$

GC_{GJ_j} is the electricity generation cost for technology *j* (in \$ GJ^{-1}),
GC_j is the average generation cost for electricity production technology *i* (in \$ kW^{-1} yr^{-1}; see equation [21]),
The other factors convert the units of GC_j first to \$ kWh^{-1}, and then to \$ GJ^{-1} (note that 1 kWh = 0.0036 GJ).

2. *Primary Energy Demands (Section 2.2.2)*

With the *endogenous* calculation of heat-energy demand, it is necessary to allocate demand for heat-energy production between the three fossil fuels.[8] The *allocation by priority* algorithm is used again.

[60] $ED_{heat_i} = ALLOCATE\ BY\ PRIORITY\left(ED_{des\_heat_i}, p_{heat_i}, NatGas, w_{heat}, ED_{heat}\right)$

ED_{heat_i} is the quantity of heat-energy demanded from fossil fuel-type *i* (in GJ yr^{-1}),
$ED_{des\_heat_i}$ is the desired heat-energy production from fossil fuel-type *i* (in GJ yr^{-1}),
p_{heat_i} is the *priority*, or relative attractiveness, of each of the three primary energy sources, with higher values being more attractive (see equation [62]),
$NatGas$ is the last member of the array, and is a parameter in the *allocate by priority* algorithm,
w_{heat} is the *width* variable in the *allocate by priority* algorithm,
ED_{heat} is the energy demand for all heat-energy (in GJ yr^{-1}; see equation [49]).
Note that $ED_{des\_heat_i}$ is distinct from $ED_{des_{heat}}$ (see equation [50]), which is the sum of the three individual desired heat productions: $ED_{des_{heat}} = \sum_{\forall\, i} ED_{des\_heat_i}$.

[8] Recall that demands for each of the fossil fuels were prescribed, not calculated, with *exogenous* energy demand.

[61] $ED_{des\_heat_i} = \varphi_{reserve_i} \cdot EP_{cap_i}$

$ED_{des\_heat_i}$ is the desired heat-energy production from fossil fuel-type *i* (in GJ yr^{-1}),
$\varphi_{reserve_i}$ is a binary flag (0, 1) that indicates whether fossil fuel reserves of type *i* are non-zero (i.e. are not exhausted), and is also used in equation [50],
EP_{cap_i} is the maximum energy production capacity of technology *i* (in GJ yr^{-1}; see equation [9]).

[62] $p_{heat_i} = SMOOTH\left(\frac{1}{\varphi_{convenience_{ff_i}} \cdot MP_i}, 10\right)$

p_{heat_i} is the *priority*, or relative attractiveness, of each of the three primary energy sources,
$\varphi_{convenience_{ff_i}}$ is a multiplier (set to 2.6, 1, and 1.4 for coal, oil, and natural gas, respectively) that accounts for the relative *attractiveness* of each of the three primary energy sources, and allows a non-economic weighting of the relative priorities,
MP_i is the market price for fossil fuel *i* (in \$ GJ^{-1}; see equation [12]).

[63] $w_{heat} = MAX(p_{heat_i})$ or $w_{heat} = VMAX(p_{heat}[i!])$

w_{heat} is the *width* variable in the *allocate by priority* algorithm.
The left-hand equation is a logical form, while the right-hand equation follows Vensim syntax. This calculation *weights* the allocation of energy demand among energy types *i* (heat and electricity) – see also the notes for equation [45].

A.6 Greenhouse Gas Emissions (Chapter 4, Sections 3.1 and 3.2)

Fossil fuel use releases greenhouse gases, either as a result of primary energy use – coal, oil, natural gas, or biomass combustion – or through secondary sources, which (for our purposes here) convert primary energy to electricity. The calculations in equations [64]-[66] take the amount of coal, oil, and natural gas extracted, and then use a *conversion factor* (IPCC, 2006: Vol. 2, Ch. 1) to determine the corresponding volume of GHGs released. Equations [67] and [68] prescribe non-energy (i.e. industrial) carbon emissions, based initially on historical figures, and then on their extrapolation into the future.

[64] $E_{coal} = \kappa_{combust} \cdot \varphi_{coal} \cdot R_{depl_{coal}}/1000$

E_{coal} is the mass of carbon emissions[9] released from the combustion of coal (in Gt C yr^{-1}),
$\kappa_{combust}$ is necessary because the combustion process uses 99%, not 100%, of its fuel,
φ_{coal} is the conversion factor for coal (set to 0.518 $t_C\ t_{coal}^{-1}$; see section 2.1),
$R_{depl_{coal}}$ is the calculated resource depletion rate (in Mt yr^{-1}; see equation [2]),
The final factor of 1000 converts from Mt to Gt.

[65] $E_{oil} = \kappa_{combust} \cdot \varphi_{oil} \cdot R_{depl_{oil}}/1000$

E_{oil} is the mass of carbon emissions released from the combustion of oil (in Gt C yr^{-1}),
$\kappa_{combust}$ is necessary because the combustion process uses 99%, not 100%, of its fuel,

[9] Most sources draw a clear distinction between combustion-based *carbon* emissions and *carbon dioxide* emissions – specifically, 1 t_C corresponds to 3.667 t_{CO2}, because of the ratio of molecular masses of C to CO_2 (44 : 12).

φ_{oil} is the conversion factor for oil (set to 0.119 t_C bbl^{-1}; see section 2.2),
$R_{depl_{oil}}$ is the calculated resource depletion rate (in MB yr^{-1}; see equation [2]),
The final factor of 1000 accomplishes several unit conversions.

[66] $E_{nat\ gas} = \kappa_{combust} \cdot \varphi_{nat\ gas} \cdot R_{depl_{nat\ gas}} \cdot 1000$

$E_{nat\ gas}$ is the mass of carbon emissions released from combustion of natural gas (in Gt C yr^{-1}),
$\kappa_{combust}$ is necessary because the combustion process uses 99%, not 100%, of its fuel,
$\varphi_{nat\ gas}$ is the conversion factor for oil (set to 0.000525 t_C m^{-3}; see section 2.3),
$R_{depl_{nat\ gas}}$ is the calculated resource depletion rate (in Tm^3 yr^{-1}; see equation [2]),
The final factor of 1000 accomplishes several unit conversions.

[67] $E_{cement_{\rightarrow 2005}} = prescribed$

$E_{cement_{2005\rightarrow}} = 5.056 \cdot t - 9884.3$

E_{cement} represents the carbon emissions from cement production (in Gt C yr^{-1}).
Prior to 2005, emissions are prescribed from Marland et al. (2008) data. After 2005, emissions are calculated from the second equation (explained in Chapter 4, section 3.2).

[68] $E_{flaring_{\rightarrow 2005}} = prescribed$

$E_{flaring_{2005\rightarrow}} = 5.394 \times 10^{93} \cdot t^{-27.899}$

$E_{flaring}$ represents the carbon emissions from the flaring of natural gas (in Gt C yr^{-1}).
Prior to 2005, emissions are prescribed from Marland et al. (2008) data. After 2005, emissions are calculated from the second equation (explained in Chapter 4, section 3.2).

Appendix B: Electricity Plant Construction in FREE

B. Electricity Plant Construction

The realization that electricity-production capacity is required does not translate immediately into its availability; instead, significant delays exist between the initiation of planning and construction and the connection of a new electricity plant to the grid, as shown in Table A-1.

Table A-1: Time required to construct and license power plants in the U.S.[1]

Plant Type	Years
Nuclear	8-14
Fossil Fuel-fired Steam	6-10
Combined-cycle Units	4-8
Combustion Turbine	3-5

[1] Table 8.12 in Shaalan (2001)

Fiddaman (1997) provides a reasonable (but not transparent) approach towards the modelling of an "electric plant construction pipeline", which is described next.

B.1 The Construction Pipeline in FREE

Fiddaman's (1997) construction pipeline has three parts: order, build, and install. The first component of the pipeline, **energy capital orders** (*EKO*), has several functions. It replaces depreciated capital, fills gaps between desired capital under construction (*DKC*) and actual capital under construction (*KC*) and between the desired energy capital (*DKE*) and actual capital (*KE*), and grows by the expected growth rate of energy orders (*GE*). In equation form[10],

$$EKO = MAX\left(0, \delta_i \cdot KE_i(t) + \frac{DKC_i(t) - KC_i(t)}{\tau_{kc}} + \frac{DKE_i(t) - KE_i(t)}{\tau_k} + KE_i(t) \cdot GE_i(t)\right)$$

- Of these terms, the most complicated is the desired energy capital (*DKE*), which is determined by the actual energy capital (*KE*), the marginal product of energy capital (M_k), the energy order rate (*EO*), the interest rate (*r*), and the normal energy production rate (*NEP*), as $DKE_i = \frac{KE_i \cdot M_{i,k} \cdot EO_i}{r \cdot NEP_i}$, or in units, $\$ = \frac{\{\$\} \cdot \{1/year\} \cdot \{GJ/year\}}{\{1/year\} \cdot \{GJ/year\}}$ where
    - $M_{i,k}$ depends on the capital share of production (κ_i, a constant[11]), the effective primary energy price (*PEP*), the depletion rent (*DR*), and the long-run marginal productivity effect (M_{LRei}), such that $M_{i,k} = \kappa_i \cdot (PEP_i - DR_i \cdot M_{LRe_i})$ for non-renewables and $M_{i,k} = \kappa_i \cdot PEP_i \cdot M_{LRe_i}$ for renewables;
        - The effective primary energy price, PEP_i (equation 338)[12], switches from exogenous values to endogenous values at the year 1990 over a five year period. The endogenous equation is given by $PEP_i = PP_i + DR_i$ in the case of non-renewables, and by $PEP_i = PP_i$ for renewables, where

[10] Note that the index, *i*, represents the energy source, of which Fiddaman's model has four categories: *Coal*, *OilGas*, *HN* (hydro/nuclear), and *New* (renewables).

[11] Capital share is defined in equation 383 of Fiddaman's code appendix as 0.6, 0.6, 0.8, 0.8. The "variable share" is the remaining component of production, such that *capital share* + *variable share* = 1.

[12] Equation numbers provided here refer to the equation number provided in the model code appendix of Fiddaman's thesis.

PP_i is the price for energy producers and DR_i is the depletion rent. Note that PP_i is described in detail below;

- The depletion rent, DR_i (equation 415), is set to 0 as a default, since no depletion rent is actually collected by anyone; and,
- The long-run marginal productivity effect, M_{LRei} (equation 296), is $M_{L\,\mathrm{Re}\,i} = \dfrac{NEP_i \cdot M_{RE\,i}}{KE_i}$,

  where NEP_i is the normal energy production rate, M_{REi} is the marginal resource effect (takes saturation and depletion into account – equation provided below), and KE is the energy capital.

- The energy order rate, EO_i (equation 389), depends on the short-run marginal productivity of energy ($M_{i,sr}$), the energy delivery rate (ED_i), and the perceived energy price (P_i), so that $EO_i = ED_i \left(\dfrac{M_{i,sr}}{P_i} \right)^{\eta}$; and,
  - The energy delivery rate, ED_i (equation 387), is simply a smoothed version of the energy production curve with a delay of one economic quarter;
  - The short-run marginal product of energy, $M_{i,sr}$ (equation 185), is the product of the short-run marginal product of the aggregate energy good and the short-run marginal output of the aggregate energy good per unit of physical energy input.
  - The perceived energy price, P_i (equation 197), is the operative energy price smoothed by a perception delay. The operative energy price is the effective primary energy price (PEP_i) plus the total tax plus the unit distribution costs all multiplied by the energy price discount (set to 1 in the normal case).
- Finally, the normal energy production rate depends on the initial energy production ($EP_i(0)$), a resource effect (RE_i) that models the effects of depletion and saturation on the average productivity of capital, and a normal effective energy capital ratio ($KE_{norm\ eff\ ratio}$) that measures the current versus initial production effort, with adjustments for capital scale, technology, and varying input intensity. The normal energy production rate (equation 313) is given as $NEP_i = EP_i(0) \cdot RE_i \cdot KE_{norm\ eff\ ratio}$.
  - The resource effect (equation 315) is given by,

    $$RE_i = \left[\varsigma_i \cdot \left(\frac{R_i(t)}{R_i(0)} \right)^{\gamma_i} + (1-\varsigma_i) \cdot KE_{norm\,eff\ ratio_i}{}^{\gamma_i} \right]^{\frac{1}{\gamma_i}} \Big/ KE_{norm\,eff\ ratio_i}$$

    where ς_i is the resource share[13], R_i is the resource remaining, γ_i is the resource coefficient (related to the elasticity by $\gamma_i = (\sigma_i - 1)/\sigma_i$, where $\sigma = 0.7$ for non-renewables and 0.5 for renewables), and
  - The normal effective energy capital ratio (equation 312) is given by,

    $$KE_{norm\,eff\ ratio_i} = \frac{KE_i}{KE_{ref_i}} \cdot Tech_E \cdot Intens_{KE\,eff\ i}$$

    where KE_{ref} is the initial energy capital, $Tech_E$ (equation 375) is the energy technology multiplier, and $Intens_{KE\,eff}$ (equation 311) is the ratio of current versus initial ratio of output to capital[14].

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[13] The resource share, ς_i, represents the share of fixed factors (resource endowment) in energy production.

- For renewable resources, its equation is given by, $\varsigma_{renew} = \left(R_{\lim renew} / EP_{renew}(0) \right)^{\gamma_{renew}}$; and,
- For non-renewable resources, the resource share equation is $\varsigma_{non} = \left(\dfrac{R_{non}(0)}{\tau_{dep\,\min} \cdot EP_{non}(0)} \right)^{\gamma_{non}}$.

For both equations, R_i represents the resource remaining – in the case of renewables, the resource remaining is the theoretical maximum production, while for non-renewables, it represents the maximum extractable amount. The other elements of the equations are the initial energy production, $EP_i(0)$, the resource coefficient, γ, and the minimum time to depletion, $\tau_{dep\ min}$ (set to 20 years).

[14] The ratio of the current to initial ratio of output to capital, $Intens_{KE\ eff}$ (equation 311), is,

- Note that Fiddaman (1997) uses a different, simpler form of this equation in the model code Appendix (equation 279), but that its constituent parts work out to the same formula. The simpler equation is $DKE_i = KE_i \cdot P_{pressure_i} \cdot KE_{rtn\ rate\ effect_i}$, where,
  - $P_{pressure\ i}$ is the production-pressure adjustment to energy capital, given by $P_{pressure_i} = EO_i / NEP_i$, where EO_i and NEP_i are given above; and,
  - $KE_{rtn\ rate\ effect\ i}$ is the effect of return rate on the energy capital, and is given in equation 282 of Fiddaman's code appendix. The return rate effect is exogenous until 1990 (and set to 1), and then switches to an endogenous rate over the course of five simulated years, after which point $KE_{rtn\ rate\ effect_i} = RR_{perc}^{\rho_{rtn}}$, where RR_{perc} is the perceived relative return rate and smoothes the quotient of the marginal product of energy capital (M_k) and the energy capital cost (in other words, M_k / KE_{cost}), which is the sum of the Ramsey interest rate and the inverse of the capital lifetime, and the return coefficient, ρ_{rtn} is set to 1.
- The desired energy capital under construction is $DKC_i = KE_i \cdot (\delta_i + GE_i) \cdot \tau_{kc}$, with depreciation ($\delta_i$), expected growth ($GE_i$), and construction delay (τ_{kc}) terms.
- The expected growth (GE_i) variable uses a Vensim function called "trend" that uses the energy order rate (EO_i) and its variation over five years.

The energy capital under construction (*KC*) has a relatively simple structure, since it is a stock. Its equation is,

$$KC_i(t) = \int \left(EKO_i(t) - \frac{KC_i(t)}{\tau_c} \right) dt$$

which is similar to the energy capital (*KE*) equation,

$$KE_i(t) = \int \left(\frac{KC_i(t)}{\tau_c} - \delta_i \cdot KE_i(t) \right) dt$$

B.2 Comments on Electric Plant Construction in Our Model

In the case of our energy sector, some aspects of Fiddaman's approach toward the first pipeline component (**energy capital orders**, *EKO*) would be hard to implement, since the economy and energy sectors are separated more explicitly in our approach than in Fiddaman's; however, there are useful features of the FREE approach that are worth consideration. Certainly, the depreciation and expected growth terms should be fairly straightforward to implement, which means that the desired energy capital under construction would be relatively straightforward to model as well. The desired energy capital (*DKE*) will be more difficult, particularly if we use a marginal productivity approach.

$$Intens_{KE\ eff\ i} = VIntens_{rel\ i}^{1-\kappa_i} = \left(\frac{KE_{\cos t\ i} \cdot KE_i(0) \cdot (1-\kappa_i)}{\kappa_i \cdot VC_{ref\ i}} \right)^{1-\kappa_i}$$

where $VIntens_{rel}$ is the relative variable intensity (equation 398), which represents the ratio of current to initial intensity of variable inputs to energy production. The intensity of variable (vs. capital) inputs to production falls as interest rates fall.

Appendix C: Fuel Prices in FREE

This section discusses Fiddaman's (1997) calculations for energy prices – simply because his equations are described in detail, while others are not.

C. Fiddaman's Approach to Energy Pricing

Fiddaman (1997: 107) gives the following equation for energy price, which seems a good place to start:

$$P_i = PP_i + \mu_i + D_i + T_i$$

where P_i is the energy price, PP_i is the producer price (capital costs plus variable costs), μ_i (or DR_i as described above; set to 0) is the depletion rent, D_i is the distribution cost (also set to 0), and T_i is the total taxes. The producer price (PP) adjusts to an *indicated producer price* (IP) with a short delay – in other words,

$$PP_i(t) = \int \frac{IP_i(t) - PP_i(t)}{\tau_p} dt$$

The indicated producer price, given as equation 343 in the model code appendix of Fiddaman (1997: 266), is

$$IP_i = PP_i \left(\frac{AC_i}{PP_i} \right)^{\gamma_a} \left(\frac{MC_i}{PP_i} \right)^{\gamma_m} \left(\frac{EO_i}{NEP_i} \right)^{\gamma_d}$$

where AC_i is the average cost of energy production, MC_i is the marginal cost of energy production, and energy orders (EO) and normal energy production (NEP) are defined above. The gamma parameters (elasticities) are the weight to average cost (γ_a), the weight to marginal cost (γ_m), and the weight to demand pressure (γ_d). They are set to 1, 0, and 2, respectively. The two new variables, AC (equation 335) and MC (equation 356), are given by,

- $AC_i = {}^{AC_{SRi}}\!/_{M_{REi}} = {}^{\left(VC_{SR\,avg\,i} + K_{\cos t\, i}\right)}\!/_{M_{REi}}$

  where AC_{SRi} is the average short-run cost of energy production, based on:

- the average short-run cost of variable inputs, $VC_{SR\,avg\,i} = VI_{des\,i} / EP_i$, where VI_{des} is the desired variable input (equation 385)[1], and EP_i is the energy production (equation 390), which is just the normal production (NEP) multiplied by the capacity utilization (a multiplier).
- The capital costs, K_{cost} (equation 336), are given by $K_{\cos t_i} = \left(KE_{\cos t_i} \cdot KE_i\right) / NEP_i$; and
- The denominator, M_{REi} (equation 309), is the marginal resource effect, which measures the marginal effect of depletion and saturation on productivity, expressed as ratio of marginal to average product, at normal utilization. It is given by a relatively complicated equation,

$$M_{RE\,i} = \left[\varsigma_i \cdot \left(\frac{R_i(t)}{R_i(0)} \right)^{\gamma_i} + (1 - \varsigma_i) \cdot KE_{norm\,eff\,ratio}{}^{\gamma_i} \right]^{\frac{1}{\gamma_i} - 1} \cdot \left(KE_{norm\,eff\,ratio}{}^{\gamma_i - 1} / RE_i \right)$$

  where ς_i is the resource share, defined above, R_i is the amount of resource remaining, γ_i is the resource coefficient (related to the elasticity by $(\sigma_i - 1)/\sigma_i$), $KE_{norm\,eff\,ratio}$ is the normal effective energy capital ratio, defined above, which represents the ratio of current to initial production effort, with adjustments for capital scale, technology, and varying input intensity, and RE_i is the resource effect, also defined above, which is the effect of depletion and saturation on the average productivity of capital.

- $MC_i = \dfrac{M_{VI\,i}}{M_{k\,eff\,ratio\,i}}$,

  where M_{VI} (equation 347) is the marginal variable cost per unit increase in capital-variable aggregate, and $M_{k\,eff\,ratio}$ (equation 346) is the marginal increase in capital-variable aggregate per unit increase in production.

  - $$M_{VI\,i} = VC_{ref\,i} \cdot \left(\frac{DKE_{eff\,ratio\,i} / Tech_E}{\left(KE_i / KE_{ref\,i}\right)^{\kappa_i}} \right)^{\frac{1}{1-\kappa_i} - 1} \Bigg/ \frac{Tech_E}{\left(KE_i / KE_{ref\,i}\right)^{\kappa_i}} \cdot \frac{1}{1 - \kappa_i}$$

    where VC_{ref} is the reference (initial) variable costs of production, $DKE_{eff\,ratio}$ is the desired effective energy capital ratio, which is the desired ratio of intensive inputs to the normal level (see equation 384), and κ_i is the capital share, as explained above.

  - $$M_{k\,eff\,ratio\,i} = \left(\left[\left(\frac{EP_{sched\,i}(t)}{EP_i(0)} \right)^{\gamma_i} - \varsigma_i \cdot \left(\frac{R_i(t)}{R_i(0)} \right)^{\gamma_i} \right] \Bigg/ (1 - \varsigma_i) \right)^{\frac{1}{\gamma_i} - 1} \cdot \left(\left[\left(\frac{EP_{sched\,i}(t)}{EP_i(0)} \right)^{\gamma_i - 1} \right] \Bigg/ \left[EP_i(0) / (1 - \varsigma_i) \right] \right)$$

    where EP_{sched} is the scheduled energy production (the minimum of the maximum capacity and the energy order rate, equation 399), $EP_i(0)$ is the initial energy production rate, ς_i is the share of

[1] VI_{des} determines the desired input of goods to energy production. It is given in equation 385 by

$$VI_{des\,i} = VC_{ref\,i} \left(\frac{DKE_{eff\,ratio\,i} / Tech_E}{\left(KE_i / KE_{ref\,i}\right)^{\kappa_i}} \right)^{\frac{1}{1-\kappa_i}}$$

The equation works as follows: the initial variable costs value (which I interpret as the cost of fuel) is affected by three factors, the desired ratio of intensive inputs to the normal level ($DKE_{eff\,ratio}$), the level of technology ($Tech_E$), and the ratio of current energy production capital to the initial capital. The $DKE_{eff\,ratio}$ is interpreted in footnote 2, below, while increasing technology decreases costs ($Tech_E$) increases from '1' over time, as does the capital – both effects serve to reduce energy costs. I think this is a reasonable way of modelling the effects involved, but it's not very transparent. I may want to consider another, similar approach.

resources (resource endowment) in production, R_i is the amount of resource remaining, and γ_i is the resource coefficient (related to the elasticity by $(\sigma_i - 1)/\sigma_i$).

C.1 Recreating Fiddaman's Approach to Energy Pricing

Fiddaman's energy price equation looks complicated, but using only the components with non-zero exponents yields

$$IP_i = PP_i\left(\frac{AC_i}{PP_i}\right)^1\left(\frac{MC_i}{PP_i}\right)^0\left(\frac{EO_i}{NEP_i}\right)^2 = AC_i\cdot\left(\frac{EO_i}{NEP_i}\right)^2 = \left(\frac{VC_{SR\,avg\,i} + KE_{\cos t\,i}}{M_{RE\,i}}\right)\cdot\left(\frac{EO_i}{NEP_i}\right)^2$$

which actually makes a great deal of sense, in most ways – although see section C.2 for notes. It states that 1) costs have two components, goods and capital costs, 2) costs depend on the availability of resources (more resources reduce costs), and 3) that costs increase nonlinearly with demand – i.e. if the ratio of energy orders to normal energy production rises quickly, the price of energy increases quickly as well. I have trouble, however, with point 2: I would have thought that variable costs are sensitive to fuel depletion and saturation, rather than both variable costs *and* capital costs being depletion- and saturation-sensitive.

Step 1: Variable Costs

To approximate Fiddaman's approach, the first step is to replicate the variable costs term of the indicated producer price equation, above, by recreating the resource share (ς), the desired effective energy capital ratio ($DKE_{eff\,ratio}$), which is the desired ratio of intensive inputs to the normal level (see equation 384), and the desired input of goods to energy production (VI_{des}) equations. The resource share equation is given above, in footnote 13, while VI_{des} is given in footnote 1; however, since $DKE_{eff\,ratio}$ has not yet been provided, it is given here[2].

$$DKE_{eff\ ratio\ i} = \left[\frac{(EP_i/EP_i(0))^{\gamma_i} - \varsigma_i(R_i/R_i(0))^{\gamma_i}}{1-\varsigma_i}\right]^{\frac{1}{\gamma_i}}$$

These three variables enter the equation for the average short-run cost of variable inputs, $VC_{SR\,avg\,i} = VI_{des\,i}/EP_i$. Note that the VC_{ref} component of the desired input of goods to energy production, VI_{des}, is obtained through Fiddaman's (1997) equation 397, which has the following form,

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[2] In terms of behaviour, increasing energy production increases the EP:$EP(0)$ ratio, which causes an increase in $DKE_{eff\,ratio}$. There are two ways to understand this effect: 1) more energy production raises the share of fuel costs (variable input) as a proportion of energy production costs, or 2) more energy production drives up demand for fuel (more likely). More resource discoveries (R_i:$R_i(0) > 1$) decrease the desired effective energy capital ratio ($DKE_{eff\,ratio}$), while depletion increases the $DKE_{eff\,ratio}$ value – the desired input of goods to energy production decreases with growing scarcity. I think this is a reasonable way of modelling the effects involved, but it's not very transparent. I may want to consider another, similar approach.

$$VC_{ref\ i} = \nu_i \cdot PTE_{ref\ i} = \nu_i \cdot \left(PP_i(0) \cdot EP_i(0)\right),$$

where PTE_{ref}, is the reference pre-tax expenditure (equation 334), $PP_i(0)$ is the initial producer price (equation 345), and $EP_i(0)$ is the initial energy production (equation 391). Both *PP*(0) and *EP*(0) values are given as input data, with an initial producer price of $1.278/GJ – this value corresponds to a value of $27.11/tonne (*calculation*: $1.278/GJ x 21.213 GJ/tonne). Multiplying the producer price by the energy produced gives the total monetary value [$] of goods inputs.

Coal price data for 1980-2005 from the EIA (2006)[3] and IEA (2007a) are provided in Table C-1 below, and are clearly variable – to demonstrate this variability further, Figure 2 of IEA (2007a) is reproduced in Figure B-1. Since there is so little correspondence between the coal price data in Table C-1, I have simply prescribed an initial coal price of $40/tonne, or $1.886/GJ[4].

Table C-1: Coal prices per metric tonne and Indices of Real Energy Prices

Year	1980	1985	1990	1995	2000	2005
EIA (2006), U.S. Data (Table 7.8)[1]	$45.61	$36.15	$26.67	$20.44	$16.78	$20.88
EIA (2006), Int'l Data[2]	--	--	--	--	$27.50	$35.30
IEA (2007a), Figure 2[3]	--	~$31	~$34	~$30	~$25	~$45
IEA (2005), Table 28[4]	176.6	168.4	131.9	--	100	*129.7*

[1] Measured in Real Dollars (2000) and short tons.
[2] From table titled "Steam Coal Prices for Electricity Generation", 1998-2006. U.S. values given. Note that IEA (2007a: xv) defines different varieties of coal.
[3] Approximate export prices listed. Export prices include production costs, and within-country transportation, but not international shipping. Import prices move in tandem with export prices, but are considerably (1.5-2x) higher.
[4] This source lists indices of real energy prices for end-users. The index year is 2000 (i.e. 2000=100). Note that 2005 value provided is actually for year 2004.

[3] Note that the EIA (2006) lists the IEA (2007a) as a data source.
[4] Prices for crude oil are available from the IEA (2008a) and correspond *roughly* to $32/barrel in 1980, including fuel cost, insurance, and freight costs, but excluding import duties – see IEA (2008a: 3) and Table 4 (Pg. 8), which shows prices rising impressively from 2000 onwards. The price in 2000 as an IEA average was about $28/barrel, and had risen to $95/barrel by March 2008. For natural gas, historical prices are harder to find – they are not available in either EIA (2006) or IEA (2008a) – but are given as a rough graph in Figure 6.7 of the EIA's *Annual Energy Review 2007* as approximately $3/10^3 ft^3 (Real 2000-USD), and in more detail in IEA (2007e), which has figures beginning in 1995. I therefore use the rough EIA *wellhead* figure of $3/thousand ft^3, and increase it to $4 to reflect transport and insurance. This value of $4/10^3 ft^3 corresponds to "roughly" $3.692/GJ.

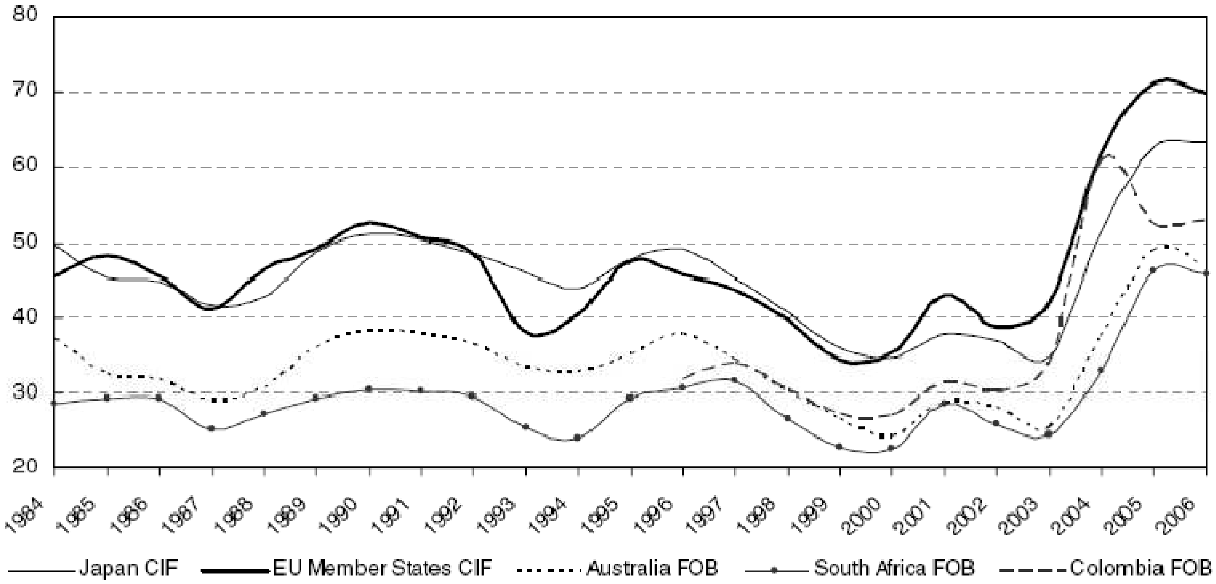


Figure C-1: Steam Coal Import and Export Value Comparison (US$/t), from Figure 2 of IEA (2007a)

Results of the First Step (VC_{SRavg})

From the VI_{des} equation (footnote 1), technological change has clear effects on the price of variable inputs. Assuming linear increases in technology (because it is easy to implement this approach until an endogenous approach is developed instead) from 1 in 1980 to 1.25 in 2005, and from 1 in 1980 to 1.125, yields the coal prices in Table C-2.

Table C-2: Simulated coal prices per metric tonne, based on alternative levels of technological change

Year	1980	1985	1990	1995	2000	2005
Higher Technological Change	$40	$36.89	$34.92	$33.26	$31.78	$30.61
Lower Technological Change	$40	$39.18	$39.22	$39.37	$39.50	$39.84

Step 2: Capital Costs

When VC_{SRavg} is added to the capital costs (equation 336), $K_{\cos t_i} = \left(KE_{\cos t_i} \cdot KE_i\right) / NEP_i$, the average cost equation, AC_i, results (excluding the M_{RE} term, of course). The capital costs equation relies on two other equations given above: 1) the energy capital costs, KE_{cost} (equation 286), and 2) the normal energy production rate, *NEP* (equation 313). The energy capital costs equation is simply $KE_{\cos t\, i} = Int(t) + 1/\tau_{KE\, i}$, where $Int(t)$ is the interest rate and τ_{KE} is the energy capital lifetime.

The *NEP* equation depends, in turn, on 1) the initial energy production, $EP_i(0)$, 2) the resource effect, *RE* (equation 315), and 3) the normal effective energy capital ratio, $KE_{norm\ eff\ ratio}$ (equation 312). Both the resource effect and normal effective energy capital ratio equations, along with the equations of their constituent parts, are given above.

The capital costs then result from the division of the annual energy capital value by the normal energy production value, or $K_{\cos t_i} = \left(KE_{\cos t_i} \cdot KE_i\right) / NEP_i$, as stated above.

Results of the Second Step (K_{cost})

The second step of the average cost calculation results in an annual cost of electricity production capital. The values obtained for coal fired plants are provided in Table C-3 below, using a constant interest rate of 6%/yr – the interest rate will come later from the economic sector of the model.

Table C-3: Simulated annual capital and variable input costs for coal-fired electricity plants, in ($/GJ)

Year	1980	1985	1990	1995	2000	2005
Annual Capital Costs	4.93	4.81	4.74	4.68	4.63	4.60
Annual Variable Inputs Costs	1.89	1.74	1.65	1.57	1.50	1.44
Average Costs	6.82	6.55	6.39	6.25	6.13	6.04

These capital costs actually compare well with figures from Shaalan (2001), who cites annual fixed capital and operation & maintenance costs of $126.25/kWyr, or $4.00/GJ (where 1 kWyr = 31.558 GJ), and with figures from Breeze (2005), who cites conventional pulverized-coal plant costs of $1079-1400/kW, or $176/kWyr = $5.58/GJ[5].

Step 3: Average Cost

The average cost equation given by Fiddaman (1997) was described above. The simpler version used here, which omits the marginal resource effect, is simply the sum of the variable (fuel) costs plus the capital costs, or $AC_i = VC_{SR\,avg\,i} + K_{\cos t\,i}$. The results are shown in Table, above.

Step 4: Indicated Producer Price

The indicated producer price, IP_i, was given above as,

$$IP_i = AC_i \cdot \left(\frac{EO_i}{NEP_i} \right)^2 = \left(VC_{SR\,avg\,i} + K_{\cos t\,i} \right) \cdot \left(\frac{EO_i}{NEP_i} \right)^2$$

where the marginal resource effect has been omitted again. In reproducing this equation in the model, I run into some problems, which are described in the next sub-section, below.

Note that, had this approach worked, I would now have energy prices (excluding carbon taxes) for the electricity produced from different energy sources, and could then use these values for

[5] The conversion from $/kW to $/kWyr to $/GJ is accomplished as follows:

1. Capital costs are subject to annual fixed charges of approximately 16%, which represent the average, or "levelized," annual carrying charges of the capital. These carrying charges result from interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit for the particular utility or company involved (Shaalan, 2001: 8.12). Therefore, the value in $/kW is simply multiplied by the annual carrying charges to get $/kWyr. In this case, $1100/kW = $176/kWyr.
2. Next, the energy units of kWyr can be converted to kJ very easily. 1 kWyr = 1 (kJ/s) x (60s/min) x … x (365.25 d/yr) = 31557600 kJ, or ~31.558 GJ. In this case, then, ($176/kWyr)(1 kWyr/31.558 GJ) = $5.58/GJ.

determining market shares, average electricity costs, and future investment (desired energy capital terms). Recall that IP_i is simply the producer price, PP_i, with the delay of one quarter, and that PP_i is the major input to the energy price equation, $P_i = PP_i + \mu_i + D_i + T_i$, presented at the start of section C.

C.2 Problems with Fiddaman's Approach

The normal energy production rate makes some sense as an idea. It represents a benchmark: the comparison of the original electricity production from coal/other fossil fuels against the effects of resource depletion on capital productivity (*RE*), and of improved energy technology, changes in capital scale, and varying input intensity ($KE_{norm\ eff\ ratio}$). In other words, without a change in electricity demand, energy production would rise or fall over time according to the factors included in *RE* and $KE_{norm\ eff\ ratio}$. Any deviation, captured in *EO*, from this "base" value would affect the average price calculated. *NEP* might be termed an "expected production value".

The problems with *NEP* are: 1) I am not sure my interpretation is correct, 2) the equations that make up its constituent parts are not well-explained, so manipulation is not really possible, and 3) the variable against which it is compared (*EO*) is neither modelled explicitly in my version of the model, nor does it make much sense in general, since no one orders electricity from coal vs. oil vs. … vs. hydro plants. They just order electricity, and if it's too expensive as an aggregate, they order less. In other words, the problems are that EO_{coal} makes no sense as a *demand* term, and that it is treated currently as an input variable rather than modelled through feedbacks.

However, it is important to note here that the *average cost* component of the *IP* equation does generate reasonable numbers, and that another approach to generating a normal energy production rate (*NEP*) term may mean that the *IP* equation can be used. Before using the *IP* equation, however, the confusing terms in its constituent parts must be explained more clearly.

APPENDIX D: ENERGY DEMAND IN COAL2

This section provides the code listing for the COAL2 model (Naill, 1977), along with a translation of the, now ancient, DYNAMO language.

D. COAL2 Model Approach

Naill (1977: 44) provides the following energy demand equations, in DYNAMO syntax[1], with translation on the right-hand side. I have recreated the model in Vensim – it is saved as the "COAL2 Energy Demand Model".

Original DYNAMO Code	**Symbols and Interpretation:**
Total Energy Demand (Naill, 1977: 44)	
1. NED.K=EGNPR70*GNP.K*DMP.K	$\boldsymbol{NED = EGNPR70 \cdot GNP \cdot DMP}$ NED = Net energy demand [Btu yr^{-1}] EGNPR70 = Energy to GNP ratio in 1970 [Btu \$$^{-1}$] GNP = Gross National Product [1970 USD yr^{-1}] DMP = Demand Multiplier from Price [Dmnl]
2. EGNPR70=5.77E4	EGNPR70 = Energy to GNP ratio in 1970 [Btu \$$^{-1}$]
3. GNP.K=GNP.J+(DT)(GNPIR.JK)	$\boldsymbol{GNP(t) = GNP_0 + \int_0^t GNPIR \cdot dt}$ GNPIR = GNP Increase Rate [1970 USD yr^{-2}]
4. GNP=GNPI	GNP = Gross National Product [1970 USD yr^{-1}]
5. GNPI=4.81E11	GNPI = Initial GNP [1970 USD yr^{-1}]
6. GNPIR.KL=GNP.K*GNPGR.K	$\boldsymbol{GNPIR = GNP(t-1) \cdot GNPGR}$ GNPGR = GNP Growth Rate [% yr^{-1}]
7. GNPGR.K=CLIP(GNPGR1.K,LTGR.K,TIME.K,RSYEAR)	GNPGR1 = GNP Growth Rate after 1973 [% yr^{-1}] LTGR = Long-term Growth Rate [% yr^{-1}]
8. RSYEAR=1973	RSYEAR = Recession Start Year
9. GNPGR1.K=CLIP(LTGR.K,RYGR.K,TIME.K,RCYEAR)	RYGR = Recession Year Growth Rate [% yr^{-1}]
10. RCYEAR=1975	RCYEAR = Recovery Year
11. LTGR.K=TABLE(LTGRT,TIME.K,1950,2010,10)*1E-2	LTGR = Long-term Growth Rate [yr^{-1}]

[1] For notes on DYNAMO, see Forrester (1961) and Meadows at al. (1974). A few general points may be useful here, however:

- In DYNAMO, variable names tend to be short, and (except for constants) have ".X" values appended to them. For example, a stock (or auxiliary variable) is written as A.K, while a flow is written as F.JK. These appendages indicate *timing*: .J indicates the previous timestep, so that A.J is the value of stock A at the previous timestep; .K indicates the current timestep, so that A.K is the value of stock A at the current time; and .L would theoretically be the next timestep – but system dynamics software does not 'look ahead' in this fashion. Intervals are used for flows, with .JK equal to the interval from the previous time to the current time; thus B.JK would be the rate of change for flow B from time J to time K. Finally, DT represents Δt. As a specific example, consider a stock A affected by an inflow B and an outflow C, shown below in DYNAMO, first, and then in standard mathematical notation underneath:
  $$A.K = A.J + (DT)(B.JK - C.JK)$$
  $$A = A_0 + \int_0^t (B - C)dt$$
- Finally, Meadows et al. (1974: 597) provide an Appendix on DYNAMO code, which begins with this note: each DYNAMO equation begins with a single letter that indicates the type of variable being defined. L = level equation, R = rate equation, A = auxiliary equation, N = initial value, C = constant, T = table, and S = supplementary equation.

	LTGRT = LTGR Table [% yr^{-1}] Range: 1950-2010, Interval: 10
12. LTGRT=3.55/3.55/3.55/3.4/3.2/3/2.8	(LTGR Table values)
13. RYGR.K=TABHL(RYGRT,TIME.K,1974,1976,1)*1E-2	RYGR = Recession Year Growth Rate [yr^{-1}] RYGRT = RYGR Table [% yr^{-1}]
14. RYGRT=-2.1/-3.6/3.5	(RYGR Table values)
15. DMP.K=SMOOTH(IDMP.K,DAT)	$\boldsymbol{DMP = smooth(IDMP, DAT)}$ DMP = Demand Multiplier from Price [Dmnl] IDMP = Indicated Demand Multiplier from Price [Dmnl] DAT = Demand Adjustment Time [yr]
16. DMP=1.09	Initial Demand Multiplier from Price value [Dmnl]
17. DAT=10	DAT = Demand Adjustment Time [yr]
18. IDMP.K=CLIP(IDMP2.K,IDMP1.K,TIME.K,PYEAR)	IDMP = Indicated Demand Multiplier from Price [Dmnl] IDMP1 = Value of IDMP before TIME = PYEAR IDMP2 = Value of IDMP after TIME = PYEAR
19. PYEAR=1977	PYEAR = Policy Year [yr]
20. IDMP1.K=TABHL(IDMP1T,AEP.K/AEPN,0,10,1)	IDMP1 = Value of IDMP before TIME = PYEAR AEP = Average Electricity Price [1970 USD Btu^{-1}] AEPN = Avg. Energy Price Normal [1970 USD Btu^{-1}]
21. IDMP1T=1.2/1/0.82/0.74/0.68/0.64/0.61/0.58/ 0.56/0.54/0.52	(IDMP1 Table values)
22. IDMP2.K=TABHL(IDMP1T,AEP.K/AEPN,0,10,1)	IDMP2 = Value of IDMP after TIME = PYEAR
23. IDMP2T=1.2/1/0.82/0.74/0.68/0.64/0.61/0.58/ 0.56/0.54/0.52	(IDMP2 Table values)
24. AEPN=0.94E-6	AEPN = Avg. Energy Price Normal [1970 USD Btu^{-1}]
25. AEP.K=(AOGP.K*NOGD.K*OGCDR.K+EP.K*TEG.K +CPRICE.K*DCUD.K*CPDR.K)/NEC.K	$\boldsymbol{AEP = \frac{(AOGP \cdot NOGD \cdot OGCDR)+(EP \cdot TEG)+(CPRICE \cdot DCUD \cdot CPDR)}{NEC}}$ AEP = Average Electricity Price [1970 USD Btu^{-1}] AOGP = Average Oil and Gas Price [1970 USD Btu^{-1}] NOGD = Net Oil and Gas Demand [Btu yr^{-1}] OGCDR = Oil & Gas Consumption/Demand Ratio [Dmnl] EP =Electricity Price [1970 USD Btu^{-1}] TEG = Total Electricity Generation [Btu yr^{-1}] CPRICE = Coal Price [1970 USD Btu^{-1}] DCUD = Direct Coal Use Demand [Btu yr^{-1}] CPDR = Coal Production/Demand Ratio [Dmnl] NEC = Net Energy Consumption [Btu yr^{-1}]
26. NEC.K=NOGD.K*OGCDR.K+TEG.K+DCUD.K*CPDR.K	$\boldsymbol{NEC = NOGD \cdot OGCDR + TEG + DCUD \cdot CPDR}$ NEC = Net Energy Consumption [Btu yr^{-1}] NOGD = Net Oil and Gas Demand [Btu yr^{-1}] OGCDR = Oil & Gas Consumption/Demand Ratio [Dmnl] TEG = Total Electricity Generation [Btu yr^{-1}] DCUD = Direct Coal Use Demand [Btu yr^{-1}] CPDR = Coal Production/Demand Ratio [Dmnl]

Interfuel Substitution (Naill, 1977: 44)

1. FEDC.K=TABHL(FEDCT,GNP.K/GNP70,.5,1.9,.2)* CDSM.K	FEDC = Fraction of Energy demanded as Coal [fraction] FEDCT = FEDC Table [fraction] GNP = Gross National Product [1970 USD yr^{-1}] GNP70 = Value of GNP in 1970 [1970 USD] CDSM = Coal Demand Substitution Multiplier [Dmnl]
2. FEDCT=.35/.15/.105/.087/.07/.06/.055/.05	(FEDCT Table values)

3. GNP70=974E9	GNP70 = Value of GNP in 1970 [1970 USD]
4. CDSM.K=TABLE(CDSMT,SCOPR.K/SCOPR70,0,2,.2)	CDSM = Coal Demand Substitution Multiplier [Dmnl] CDSMT = CDSM Table [Dmnl] SCOPR = Smoothed Coal-Oil Price Ratio [Dmnl] SCOPR70 = Value of SCOPR in 1970 [Dmnl]
5. CDSMT=5/4.5/2.5/1.7/1.3/1/.83/.71/.63/.56/.5	(CDSMT Table values)
6. SCOPR70=.52	SCOPR70 = Value of SCOPR in 1970 [Dmnl]
7. SCOPR.K=SMOOTH(COPR.K,DAT)	$\boldsymbol{SCOPR = smooth(COPR, DAT)}$ SCOPR = Smoothed Coal-Oil Price Ratio [Dmnl] COPR = Coal-Oil Profit Ratio [Dmnl] DAT = Demand Adjustment Time [yr]
8. SCOPR=.54	Initial Smoothed Coal-Oil Price Ratio [Dmnl]
9. COPR.K=CPRICE.K/AOGP.K	$\boldsymbol{COPR = CPRICE/AOGP}$ COPR = Coal-Oil Price Ratio [Dmnl] CPRICE = Coal Price [1970 USD Btu^{-1}] AOGP = Average Oil and Gas Price [1970 USD Btu^{-1}]
10. DCUD.K=FEDC.K*NED.K	$\boldsymbol{DCUD = FEDC \cdot NED}$ DCUD = Direct Coal Use Demand [Btu yr^{-1}] FEDC = Fraction of Energy demanded as Coal [fraction] NED = Net energy demand [Btu yr^{-1}]
11. FEDE.K=TABHL(FEDET,GNP.K/GNP70,0,8,1)*EDSM.K	FEDE = Fraction of Energy Demanded as Electricity [fraction] FEDET = FEDE Table [fraction] EDSM = Electricity Demand Substitution Multiplier [Dmnl]
12. FEDET=.03/.093/.14/.18/.21/.24/.26/.275/.28	(FEDET Table values)
13. EDSM.K=TABLE(EDSMT,SEPR.K/SEPR70,0,2.5,.25)	EDSM = Electricity Demand Substitution Mult. [Dmnl] EDSMT = EDSM Table [Dmnl] SEPR = Smoothed Electricity-Oil Price Ratio [Dmnl] SEPR70 = Value of SEPR in 1970 [Dmnl]
14. EDSMT=2.5/1.9/1.5/1.22/1/.78/.64/.56/.5/.44/.4	(EDSMT Table values)
15. SEPR70=8.75	SEPR70 = Value of SEPR in 1970 [Dmnl]
16. SEPR.K=SMOOTH(EPR.K,DAT)	$\boldsymbol{SEPR = smooth(EPR, DAT)}$ SEPR = Smoothed Electricity-Oil Price Ratio [Dmnl] EPR = Electricity Price Ratio [Dmnl] DAT = Demand Adjustment Time [yr]
17. SEPR=13.5	Initial Smoothed Electricity-Oil Price Ratio [Dmnl]
18. EPR.K=EP.K/AOGP.K	$\boldsymbol{EPR = EP/AOGP}$ EPR = Electricity Price Ratio [Dmnl] EP =Electricity Price [1970 USD Btu^{-1}] AOGP = Average Oil and Gas Price [1970 USD Btu^{-1}]
19. NELD.K=FEDE.K*NED.K	$\boldsymbol{NELD = FEDE \cdot NED}$ NELD = Net Electricity Demand [Btu yr^{-1}] FEDE = Fraction of Energy Demanded as Elec. [fraction] NED = Net energy demand [Btu yr^{-1}]
20. NOGD.K=(1-FEDE.K-FEDC.K)*NED.K	$\boldsymbol{NOGD = (1 - FEDE - FEDC) \cdot NED}$ NOGD = Net Oil and Gas Demand [Btu yr^{-1}] FEDE = Fraction of Energy Demanded as Elec. [fraction] FEDC = Fraction of Energy demanded as Coal [fraction]

Exogenous Inputs (Naill, 1977: 44)

1. AOGP.K=TABLE(AOGPT,TIME.K,1950,2010,10)*1E-6	AOGP = Average Oil and Gas Price [1970 USD Btu^{-1}]
2. AOGPT=.65/.65/.65/1.5/2/2.1/2.1	(AOGP Table values)
3. CPRICE.K=TABLE(CPRICET,TIME.K,1950,2010,10)* 1E-6	CPRICE = Coal Price [1970 USD Btu^{-1}]
4. CPRICET=.34/.33/.35/.5/.6/.6/.6	(CPRICE Table values)
5. EP.K=TABLE(EPT,TIME.K,1950,2010,10)*1E-6	EP =Electricity Price [1970 USD Btu^{-1}]
6. EPT=7.16/5.76/4.66/5.4/6.2/7/7	(EP Table values)

Supplementary Equations (Naill, 1977: 45)

1. OGCDR.K=1	OGCDR = Oil & Gas Consumption/Demand Ratio [Dmnl]
2. CPDR.K=1	CPDR = Coal Production/Demand Ratio [Dmnl]
3. *Others not listed here...*	

Notes

- AEP is defined in Naill (1977: 229) as the Average Electricity price. However, the form of the AEP equation and the definition of AEPN both suggest that AEP is in fact the Average Energy Price
- Relevant DYNAMO functions:
  - CLIP(T2,T1,TIME.K,PYEAR): Switches from lookup table 1 (T1) to table 2 at time=PYEAR
  - SMOOTH(Var,Adj): Smoothes a variable (Var) over an averaging time (Adj). A smooth function is a first-order delay containing one internal *level*
  - TABHL(Tab,Indep,Start,Finish,Int): Sets LHS variable to the lookup value (Tab) based on the value of the independent variable (Indep). The table is defined over the range from Start to Finish, with values set at a particular interval (Int)

D.1 Net Energy Demand

The first equation, $NED = EGNPR70 \cdot GNP \cdot DMP$, can be rewritten as,

$$ED = \left(\frac{ED_{1970}}{Q_{1970}}\right) \cdot Q \cdot \delta_{price}$$

which captures the nature of the constituent parts slightly better, and uses symbols more in line with other documents I've written so far. In this new form, net energy demand (NED) is expressed as a variable, ED, the energy to GNP ratio in 1970 ($EGNPR70$) is expressed as the ratio of two variables at a certain time, ED_{1970}/Q_{1970}, which basically provides a baseline for comparison, the GNP value is expressed as a variable, Q, since the economic sector provides this value, and the demand multiplier from price (DMP) is expressed as a parameter, δ_{price}, since it is a lookup.

D.2 The Demand Multiplier from Price

Although the first two right-hand variables in equation 1 are straightforward, the last term, DMP, requires a closer examination. The DMP/δ_{price} values take this form:

$$\delta_{price} = SMOOTH(\lambda_{\delta_{price}}, 10)$$

where $\lambda_{\delta_{price}}$ is a lookup table that translates the average energy [see Notes above] price, AEP, into the demand multiplier, δ_{price}, after a delay of 10 years. (The translation occurs through the $IDMP$ variable.) The lookup table, $\lambda_{\delta_{price}}$, is shown in Figure C-1,

AEP/AEPN	IDMP
0	1.2
1	1
2	0.82
3	0.74
4	0.68
5	0.64
6	0.61
7	0.58
8	0.56
9	0.54
10	0.52

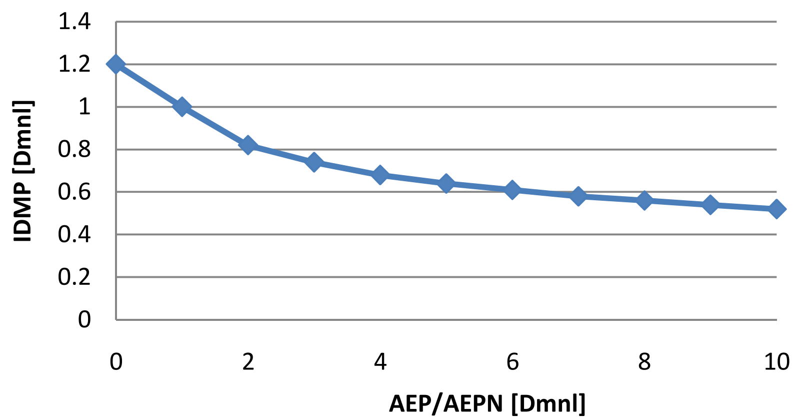


Figure D-1: Lookup table for IDMP

The independent variable, AEP, is the net price of direct oil and gas use, direct coal use, and (indirect) electricity use over the net energy consumption. In equation form, the more complicated expression, $AEP = \frac{(AOGP \cdot NOGD \cdot OGCDR) + (EP \cdot TEG) + (CPRICE \cdot DCUD \cdot CPDR)}{NEC}$, can be simplified to,

$$MP_{avg} = \frac{EC_{o\&g} + EC_{coal} + EC_{elec}}{EP}$$

where MP_{avg} is the average market price of energy (using the same terminology as in other documents), which is measured here in 1970 USD Btu^{-1} but can also be measured in $ GJ^{-1} as elsewhere, EC_i is the cost of energy from source *i* in 1970 USD, and EP is the energy production – assuming that all energy produced is used – in Btu or GJ.

Comparison of AEP or MP_{avg} with the normal energy price, $AEPN$, determines whether energy prices are low, "normal", or higher than usual. According to the lookup table values, $\lambda_{\delta_{price}}$, in Figure, low current market prices as compared with normal prices lead to more energy consumption, while higher than normal prices lead to lower energy consumption.

Instead of using a lookup table, it is also possible (and preferable from a sensitivity-testing perspective) to use an elasticity, such as,

$$\delta_{price} = SMOOTH\left(\left(\frac{AEP}{AEPN}\right)^{\rho}, 10\right)$$

where the exponent, ρ, is an elasticity < 0 – Naill (1977) uses a value of -0.28.

D.3 The Income Effect

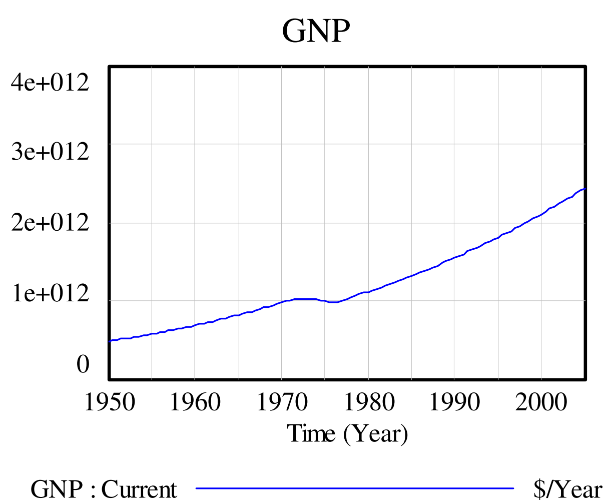
The second term in the net energy demand equation is economic output, Q. The absence of an exponent indicates that an elasticity of 1 is used, such that a 1% increase in GDP leads to a 1% increase in energy demand. However, the exponent need not be 1, and indeed simulations with a version of our model that contains the COAL2 energy demand calculation show that results can change considerably if another, even only slightly different (~0.98) elasticity is chosen.

D.4 Remaining Equations

In adapting the COAL2 energy demand model to our purposes, I required only the basic *net energy demand* equation. However, to understand the model function, I recreated the entire Naill (1977), as indicated at the beginning of this section. The equations are also presented – and deciphered – above to enable other interested readers to recreate the model. I will therefore provide no further description here, except to provide some basic results below.

D.5 Modelling Results

The results below demonstrate the basic behaviour of my recreation of the COAL2 model. Increases in the US net energy demand over time, along with the assumed changes in GNP, are shown in Figure C-2. The effects of the OPEC-caused recession in the early 1970s are readily apparent.



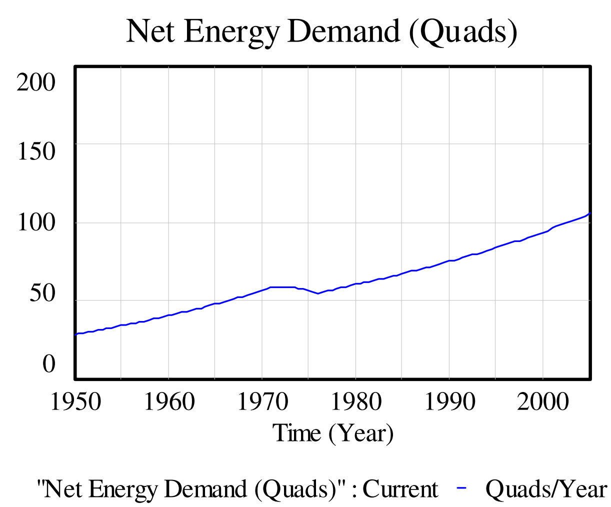


Figure D-2: Assumed changes in US GNP over time and simulated net energy demand

Average energy prices and specific prices for coal, oil & gas, and electricity are shown in Figure C-3. The coal, oil & gas, and electricity prices are assumed, while the average energy price is calculated – according to the *AEN* equation above – from the assumed component prices and calculated coal, oil & gas, and electricity demand values.

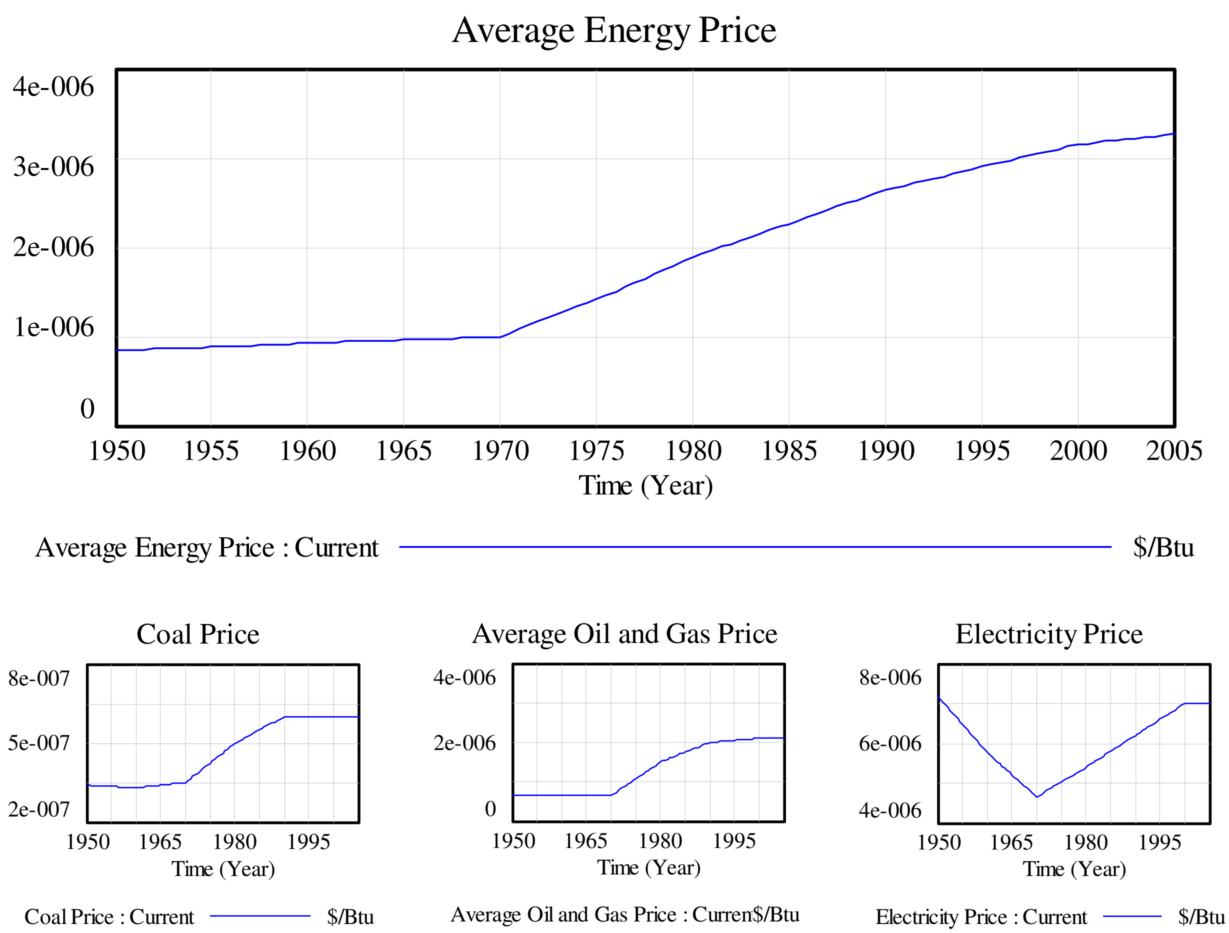


Figure D-3: Average energy price, and coal, oil & gas, and electricity prices ($ Btu^{-1})

These prices then affect the *demand multiplier from price* (section D.2), with the unsmoothed and smoothed values (*IDMP* and *DMP*) shown in Figure C-4.

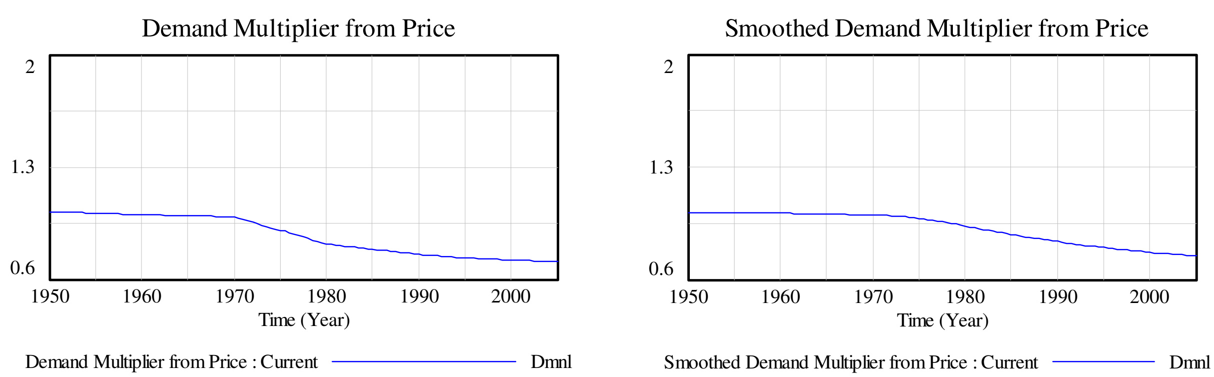


Figure D-4: Demand multiplier from price, raw value and smoothed

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