SWP-633

A Model of World Energy Markets and OPEC Pricing

WORLD BANK STAFF WORKING PAPERS
Number 633

WORLD BANK STAFF WORKING PAPERS
Number 633

A Model of World Energy Markets and OPEC Pricing

Boum-Jong Choe

The World Bank
Washington, D.C., U.S.A.

First printing February 1984

Manufactured in the United States of America

This is a working document published informally by the World Bank. To present the results of research with the least possible delay, the typescript has not been prepared in accordance with the procedures appropriate to formal printed texts, and the World Bank accepts no responsibility for errors. The publication is supplied at a token charge to defray part of the cost of manufacture and distribution.

The views and interpretations in this document are those of the author(s) and should not be attributed to the World Bank, to its affiliated organizations, or to any individual acting on their behalf. Any maps used have been prepared solely for the convenience of the readers; the denominations used and the boundaries shown do not imply, on the part of the World Bank and its affiliates, any judgment on the legal status of any territory or any endorsement or acceptance of such boundaries.

The full range of World Bank publications is described in the *Catalog of World Bank Publications;* the continuing research program of the Bank is outlined in *World Bank Research Program: Abstracts of Current Studies.* Both booklets are updated annually; the most recent edition of each is available without charge from the Publications Sales Unit of the Bank in Washington or from the European Office of the Bank, 66, avenue d'Iéna, 75116 Paris, France.

Boum-Jong Choe is an economist with the Commodity Studies and Projections Division of the World Bank's Economic Analysis and Projections Department.

Library of Congress Cataloging in Publication Data

Choe, Boum Jong.
A model of world energy markets and OPEC pricing.

(World Bank staff working papers ; no. 633)
Bibliography: p.
1. Energy industries--Mathematical models. 2. Petroleum industry and trade--Price policy--Mathematical models. 3. Organization of Petroleum Exporting Countries. I. Title. II. Series.
HD9502.A2C469 1984 338.2'3 84-2218
ISBN 0-8213-0328-7

ABSTRACT

This paper presents an analysis of the world energy and petroleum markets, carried out by means of an econometric simulation model. The model accepts a certain pricing path for OPEC crude oil (a price seen as being chosen by OPEC mainly on the basis of its revenue implications) together with assumptions about GDP and population growth, and generates energy balance projections for seven world regions--three industrial country regions and four developing country groups. The demand side of the model consists of three end-use sectors (transportation, industrial and residential/commercial) and one energy tranformation sector (thermal power generation). The model presently has an endogenous supply specification only for coal. The performance of the model in simulating the historical period of the 1970s was reasonably satisfactory.

Simulation results under a range of assumptions about future economic growth and OPEC pricing portend that world demand for energy and petroleum is likely to remain at relatively low levels throughout the 1980s and the early 1990s. Past and expected petroleum price increases will provide a strong and sustained incentive to substitute away from energy and petroleum; enough to keep the demand for OPEC oil comfortably within OPEC's productive capacity through the early 1990s. Coal will play a key role as a substitute fuel for the next 20 years. About two-thirds of the projected incremental demand for primary energy between 1978 and the year 2000 is accounted for by developing countries.

It is found that present values of future OPEC export revenues do not differ substantially for the alternative pricing paths considered to be reasonable for OPEC to follow. The results show that a pricing path that calls for steady price increases at a moderate rate starting from the second half of the 1980s is probably close to the optimal long-term pricing path for OPEC. Lower price elasticities of final energy demand and/or higher rates of economic growth in non-OPEC countries result in substantially higher revenues for OPEC, but the relative rankings of the alternative pricing paths do not change appreciably. Revenues of the two OPEC subgroups (capital-surplus and capital-deficit groups) show greater sensitivity to the choice of a production prorationing regime than to the choice of a pricing path. OPEC revenues are also shown to be sensitive to pricing policies of the oil-importing countries.

EXTRACTO

En este documento se presenta un análisis de los mercados mundiales de productos energéticos y petróleo realizado utilizando un modelo econométrico de simulación. El modelo toma como base una cierta trayectoria de los precios de los crudos de la OPEP (un precio que se considera escogido por los miembros de la OPEP principalmente en razón de sus efectos en materia de ingresos), así como varios supuestos sobre el crecimiento del PIB y de la población, y permite derivar proyecciones sobre el equilibrio energético correspondientes a siete regiones del mundo: tres regiones de países industriales y cuatro grupos de países en desarrollo. La función demanda del modelo consta de tres sectores de usos finales (los de transportes, industria y residencial/comercial) y un sector de transformación de la energía (la generación de energía térmica). El modelo en su actual forma tiene una especificación endógena de la oferta únicamente para el carbón. La aplicación del modelo en la simulación del período histórico del decenio de 1970 dio resultados razonablemente satisfactorios.

Los resultados de la simulación, partiendo de una serie de supuestos sobre el crecimiento económico futuro y los precios de la OPEP, auguran que la demanda mundial de energía y de petróleo probablemente se mantendrá a niveles relativamente bajos durante todo el decenio de 1980 y comienzos del de 1990. Los aumentos de los precios del petróleo, tanto pasados como previstos, proporcionarán un incentivo fuerte y sostenido para la sustitución de petróleo y otros productos energéticos, suficiente como para mantener la demanda del petróleo de la OPEP a un nivel atendible dentro de los límites de la capacidad productiva de sus países miembros hasta comienzos del decenio de 1990. El carbón jugará un papel clave como combustible de sustitución durante los próximos 20 años. Entre 1978 y el año 2000, aproximadamente dos terceras partes del aumento de la demanda de energía primaria indicado por las proyecciones corresponden a los países en desarrollo.

Se observa que los valores actualizados de los ingresos futuros de las exportaciones de petróleo de los miembros de la OPEP no difieren considerablemente cualesquiera que sean las distintas trayectorias en cuanto a precios que la OPEP pueda razonablemente seguir. Los resultados muestran que una trayectoria de precios que requiere aumentos sostenidos de éstos a un ritmo moderado a partir de la segunda mitad del decenio de 1980 probablemente se acerca bastante a la trayectoria óptima a largo plazo de los precios de la OPEP. Unas elasticidades-precio más bajas de la demanda final de energía o tasas más elevadas de crecimiento económico en los países que no son miembros de la OPEP, o ambas cosas, dan como resultado un volumen de ingresos considerablemente más elevado para la OPEP, pero la clasificación relativa de las distintas trayectorias en materia de precios no cambia apreciablemente. Los ingresos de los dos subgrupos de países miembros de la OPEP (los que tienen superávit y los que tienen déficit de capital) muestran un mayor grado de sensibilidad a la selección de un régimen de producción de racionamiento a prorrata que a la selección de una trayectoria dada de precios. Asimismo, los ingresos de la OPEP se manifiestan sensibles a las políticas de precios de los países importadores de petróleo.

Le présent document est une analyse des marchés mondiaux de l'énergie et du pétrole fondée sur un modèle de simulation économétrique. Ce modèle a été établi en fonction d'une certaine orientation en matière de fixation des prix du pétrole brut de l'OPEP (ce prix semblant être établi par l'OPEP sur la base, principalement, des revenus en découlant) et d'hypothèses en matière de croissance du PIB et de la population; d'autre part, il présente des projections relatives aux soldes des ressources énergétiques dans sept régions du monde, à savoir trois régions de pays industrialisés et quatre groupes de pays en développement. Du côté de la demande, le modèle comprend trois secteurs d'utilisation finale (secteur des transports, secteur industriel et secteur résidentiel/commercial) et un secteur de transformation de l'énergie (production d'énergie thermique). Seul le secteur du charbon présente une spécification d'offre endogène. Le modèle réussit de façon raisonnablement satisfaisante à simuler la période couvrant les années 70.

Les résultats de la simulation, dans le cadre d'une gamme d'hypothèses concernant la croissance économique future et l'évolution des prix pratiqués par l'OPEP dans l'avenir, donnent à prévoir que la demande mondiale d'énergie et de pétrole restera probablement à des niveaux relativement faibles jusqu'à la fin des années 80 et pendant le début des années 90. Les augmentations passées et envisagées du prix du pétrole encourageront vigoureusement et de façon soutenue la substitution d'autres ressources aux ressources énergétiques et pétrolières, ce qui devrait suffire à maintenir les besoins en pétrole provenant de l'OPEP dans les limites de la capacité de production de l'OPEP pendant les premières années de la décennie 90. Le charbon sera au premier rang des carburants de

substitution pendant les vingt prochaines années. Les deux tiers environ de l'augmentation prévue de la demande d'énergie primaire de 1978 à l'an 2000 proviendra des pays en développement.

Le présent exercice établit que les valeurs actuelles des recettes d'exportation futures de l'OPEP ne varient pas sensiblement en fonction des diverses hypothèses de prix que, selon les estimations, les pays de l'OPEP pourraient raisonnablement appliquer. Les résultats indiquent que la tendance optimale à long terme des prix de l'OPEP serait probablement proche du cheminement suivant : des hausses régulières des prix, d'un taux modéré, à partir de la deuxième moitié des années 80. Une réduction dans l'élasticité des prix de la demande finale d'énergie et/ou une hausse du taux de croissance économique dans les pays ne faisant pas partie de l'OPEP entraînent une augmentation considérable des recettes de l'OPEP, mais le classement des diverses hypothèses relatives aux prix pratiqués par l'OPEP ne varie pas sensiblement. Les recettes enregistrées par les deux sous-groupes de l'OPEP (groupe à excédent de capitaux et groupe à déficit de capitaux) indiquent une sensibilité plus grande à l'égard du choix d'un régime de rationnement de la production qu'à l'égard du choix d'une tendance en matière de fixation des prix. D'autre part, le modèle indique une sensibilité des recettes de l'OPEP à l'égard des politiques de fixation des prix adoptées dans les pays importateurs de pétrole.

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY..... 1

Annex 1.1: COUNTRY GROUPS IN WEPM..... 8

II. THE MODEL STRUCTURE..... 9

2.1. OPEC and World Energy Markets..... 9

2.2. Interrelationship of Energy Markets..... 16

Petroleum Market and Product Pricing..... 16
Relationships Between Energy Markets..... 19

III. MODELING THE DEMAND FOR ENERGY..... 24

3.1. A Methodological Overview..... 24

3.2. Transportation Demand for Energy 28

Demand for Gasoline..... 28
Demand for Diesel Oil for Road Transportation..... 36
Demand for Aviation Fuels..... 38
Fuel Demands for Other Transportation..... 39

3.3. Industrial Demand for Energy 40

Factor Substitution and Industrial Demand for Energy... 41
Interfuel Substitution in Industrial Energy Consumption..... 45
Demand for Metallurgical Coal by the Iron and Steel Industry..... 48

3.4. Residential Demand for Energy..... 49

Total Residential Demand for Energy..... 51
Interfuel Substitution in Residential Sector..... 55

3.5. Fuel Substitution in Electricity Generation..... 57

Fuel Efficiency of Thermal Electricity Generation..... 58
Fuel Substitution in Thermal Electricity Generation.... 59

Annex 3.1. DATA SOURCES AND LIMITATIONS..... 62

IV. SUPPLIES OF CONVENTIONAL AND NONCONVENTIONAL ENERGY..... 64

4.1. Conventional Petroleum and Natural Gas..... 65

4.2. Coal Supplies and Costs..... 66

Production and Reserves..... 66
Coal Cost Structure and Long-Term Coal Supply Model.... 69
Factor Prices and Productivities..... 77
Short-term Dynamics and Capacity Expansion..... 80
Other Related Costs..... 81

4.3. Hydro and Nuclear Electricity..... 82

4.4. Backstop Technologies and Costs..... 86

V. SIMULATION RESULTS..... 90

5.1. Simulation of the 1970s..... 91

5.2. The Base-Case Projections to the Year 2000..... 96

Assumptions..... 96
World Energy Balance..... 98
Sectoral Demands and Interfuel Substitution..... 105
International Trade and Export Prices..... 110

5.3. Simulations under Alternative Scenarios..... 111

High Economic Growth Scenario..... 111
Low Demand Adjustment Scenario..... 113
Low Nuclear Power Scenario..... 116
Tariff Scenario..... 116
Comparison with Other Projections..... 117

5.4. Long-Term OPEC Pricing and Production..... 120

Demand for OPEC Oil and OPEC Revenues..... 121
OPEC Pricing Under the Base Case..... 123
The Case of Low Demand Adjustments..... 128
Impact of Alternative Assumptions on OPEC Revenues..... 130

Annex 5.1. LIST OF EQUATIONS AND VARIABLES IN WEPM..... 134

Annex 5.2. REGIONAL AND SECTORAL ENERGY BALANCE PROJECTIONS..... 150

REFERENCES..... 164

LIST OF TABLES

Table No.		Page No.
2.1	OPEC PETROLEUM PRODUCTION AND RESERVES	13
2.2	ALTERNATIVE OPEC PRODUTION SHARES	15
2.3	EX-REFINERY PRODUCT PRICE DIFFERENTIALS FOR WORLD REGIONS AND INTERNATIONAL PRODUCT MARKET	19
3.1	WORLD GASOLINE CONSUMPTION	29
3.2	CAR DEMAND PARAMETERS	31
3.3	GASOLINE DEMAND PARAMETERS	33
3.4	ELASTICITY ESTIMATES OF THE DEMAND FOR GASOLINE	35
3.5	WORLD CONSUMPTION OF DIESEL OIL AND ITS DEMAND ELASTICITIES	37
3.6	WORLD CONSUMPTION OF AVIATION FUELS AND ITS DEMAND ELASTICITIES	39
3.7	WORLD FUEL DEMAND FOR OTHER TRANSPORTATION	40
3.8	THE STRUCTURE OF INDUSTRIAL ENERGY DEMAND	41
3.9	PARAMETERS OF AGGREGATE INDUSTRIAL ENERGY DEMAND	42
3.10	ESTIMATES OF PRICE ELASTICITY OF INDUSTRIAL ENERGY DEMAND	43
3.11	LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THE INDUSTRIAL SECTOR--WEPM AND OTHER STUDIES	46
3.12	ENERGY SAVING TECHNICAL PROGRESS IN THE IRON AND STEEL INDUSTRY	49
3.13	THE STRUCTURE OF RESIDENTIAL ENERGY CONSUMPTION	50
3.14	INCOME AND PRICE ELASTICITIES OF RESIDENTIAL ENERGY DEMAND	52
3.15	ESTIMATES OF RESIDENTIAL ENERGY DEMAND ELASTICITIES	53
3.16	LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THE RESIDENTIAL SECTOR--WEPM AND OTHER STUDIES	56
3.17	LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THERMAL ELECTRICITY GENERATION--WEPM AND OTHER STUDIES	60

Annex Table 3.1: SIGNIFICANCE OF THE DEVELOPING COUNTRIES WITH SECTORAL CONSUMPTION DATA..... 63

4.1 BASE-CASE PROJECTIONS OF PETROLEUM AND NATURAL GAS SUPPLIES.. 65

4.2 WORLD COAL RESERVES AND PRODUCTION..... 68

4.3 ESTIMATES OF COAL MINING COSTS..... 70

4.4 COMPOSITION OF COAL MINING COSTS..... 72

4.5 ESTIMATED PERCENT COST INCREASES OVER TIME AT THE 1976 RATES OF PRODUCTION IN THE UNITED STATES..... 74

4.6 LONG-RUN COST FUNCTION AND PRODUCTION SHARES OF COAL 76

4.7 MINING WAGES AND LABOR PRODUCTIVITY OF MAJOR COAL PRODUCING COUNTRIES..... 78

4.8 BASE CASE SUPPLIES OF HYDRO/GEOTHERMAL AND NUCLEAR ELECTRICITY..... 83

4.9 COST ESTIMATES FOR NUCLEAR AND FOSSIL FUEL POWERED ELECTRICITY GENERATION..... 85

4.10 PRODUCTION COSTS OF SYNTHETIC LIQUID FUELS..... 88

4.11 WORLD SYNFUELS PRODUCTION TO YEAR 2000..... 89

5.1 BASE-CASE GROWTH RATES OF GDP, GDP PER CAPITA AND INDUSTRIAL GDP BY REGIONS..... 97

5.2 WORLD ENERGY BALANCE PRODUCTIONS TO 2000..... 99

5.3 WORLD ENERGY BALANCE PROJECTIONS TO 2000..... 100

5.4 EFFICIENCIES OF FINAL ENERGY CONSUMPTION--HISTORICAL (1970-78) AND PROJECTED (1978-2000)..... 106

5.5 SECTORAL FUEL SHARES: HISTORICAL (1970-78) AND PROJECTED (1978-2000)..... 108

5.6 HIGH ECONOMIC GROWTH SCENARIO..... 114

5.7 LOW DEMAND ADJUSTMENT SCENARIO..... 115

5.8 IMPACT OF A TARIFF ON PETROLEUM IMPORTS..... 117

5.9 A COMPARISON OF WEPM AND IEA PROJECTIONS..... 119

5.10 PRICE ELASTICITY OF NON-OPEC DEMAND FOR OPEC OIL..... 123

5.11 OPEC PETROLEUM EXPORTS AND REVENUES UNDER ALTERNATIVE PRICING PATHS..... 124

5.12 PRESENT VALUES OF OPEC EXPORT REVENUES AND RESERVES: BASE-CASE DEMAND ADJUSTMENTS..... 127

5.13 PRESENT VALUES OF OPEC EXPORTS AND RESERVES: THE LOW DEMAND ADJUSTMENT CASE..... 129

5.14 PRESENT VALUES OF OPEC EXPORTS AND RESERVES UNDER ALTERNATIVE ASSUMPTIONS..... 132

LIST OF FIGURES

2.1 SCHEMA FOR DETERMINATION OF CRUDE OIL AND PETROLEUM PRODUCT PRICES..... 17

2.2 ENERGY MARKET INTERACTIONS AND DETERMINATIONS OF EQUILIBRIUM PRICES..... 22

5.1 DEMAND SIMULATION FOR THE 1970S..... 93

5.2 WORLD PRIMARY ENERGY DEMAND BY REGION..... 101

5.3 WORLD PRIMARY ENERGY DEMAND BY FUEL..... 102

5.4 NET IMPORTS AND EXPORTS OF PETROLEUM BY REGION..... 103

5.5 INTERNATIONAL EXPORT PRICES OF FUELS..... 112

5.6 ALTERNATIVE SCENARIOS FOR OPEC PRICING..... 122

ACRONYMS AND ABBREVIATIONS

b/d	-	Barrels per day
mbd	-	Million barrels per day
boe	-	Barrels of oil equivalent
mboe	-	Million barrels of oil equivalent
bdoe	-	Barrels per day of oil equivalent
toe	-	Tons of oil equivalent
mtoe	-	Million tons of oil equivalent
mbdoe	-	Million barrels per day of oil equivalent
tce	-	Tons of hard coal equivalent
mtce	-	Million tons of hard coal equivalent
BTU(s)	-	British thermal unit(s)
KWh	-	Kilowatt hour
GWh	-	Gigawatt hour
NGL	-	Natural gas liquids
EEC	-	European Economic Community
IEA	-	International Energy Agency
OECD	-	The Organization for Economic Co-operation and Development
OPEC	-	The Organization of Oil-Exporting Countries
UN	-	The United Nations
NOAM	-	Industrial North America
WEUR	-	Industrial Western Europe
JANZ	-	Japan, Australia, New Zealand
CSEX	-	Capital-Surplus Oil-Exporting Countries
CDOP	-	Capital-Deficit OPEC countries
NOEX	-	Non-OPEC Net Oil-Exporting Developing Countries
OIDC	-	Net Oil-Importing Developing Countries

CONVERSION FACTORS

1 toe = 7.3 boe = 1.47 tce = 40.8 million BTUs
1 mtoe = 0.02 bdoe
1,000 cubic meters of natural gas = 0.926 toe
1 million KWh = 3,412 million BTUs = 123 tce = 83.5 toe = 610 boe

I. INTRODUCTION AND SUMMARY

This paper presents an analysis of the world energy and petroleum markets with the aid of a state-of-the-art econometric simulation model, henceforth referred to as the World Energy and Petroleum Model (WEPM). It is formulated along the traditional lines of modeling the petroleum and energy markets, but with greater details about various energy markets and market interactions between fuels.

The world petroleum market is viewed as consisting of a dominant oligopolistic cartel, the Organization of Petroleum Exporting Countries (OPEC), and the competitive fringe, the non-OPEC producers. OPEC sets the international market price of crude oil (a price seen as being chosen mainly on the basis of its revenue implications for OPEC) and supplies the resulting demand for OPEC petroleum, which is determined as a residual (world total demand for petroleum minus non-OPEC supplies of petroleum). The model accepts a certain pricing path for OPEC crude oil, together with assumptions about GDP and population growth, and generates energy balance projections including the demand for OPEC petroleum. The model also calculates the discounted present value of revenues for OPEC as a whole and for its subgroups separately.

The model has three industrial country regions (North America, Western Europe and Japan/Australia/New Zealand) and four developing country groups (capital-surplus oil exporters, capital-deficit OPEC, non-OPEC oil exporters and oil-importing developing countries). The centrally planned economies enter the model exogenously, as net exporters of energy. 1/ Simulations with the model are carried out year by year from 1978 to the year 2000 (terminal year). Simple assumptions are made with regard to the value of OPEC's remaining petroleum reserves in the terminal year.

The demand side of the model consists of three end-use sectors (transportation, industrial and residential/commercial) and one energy

---

1/ Details of the country groups are shown in Annex 1.1. Throughout this paper, the term "world" is defined to include only the market-economy countries unless noted otherwise.

transformation sector (thermal power generation). The transportation sector consists of demand for gasoline, diesel oil, jet kerosene, and an assortment of fuels for rail, barge, and marine transportation. Final energy demands by the industrial and residential/commercial sectors are determined by aggregate output/income and energy prices. The demand for the individual fuels--coal, petroleum, natural gas, and electricity--is determined by an interfuel substitution model where the cost shares of the fuels are determined by the relative fuel prices. The demand for electricity is determined as a result of interfuel competition in the final end-use sectors. The three primary fossil fuels also compete in the thermal power industry, the only energy transformation sector in the model.

An important feature of the demand specification is allowance for the fact that demand adjustments to higher prices take many years because of the time required for retrofitting and replacement of capital stock. A polynomial lag structure stretching over more than ten years is used to represent the dynamic adjustment path for the final energy demand sectors. The model also adopts the view that the true long-term price elasticity of energy demand should be close to typical international cross-sectional, time-series estimates, which are about twice as large as those obtained from time series alone.

The model presently has an endogenous supply specification only for coal. Supplies of hydro/geothermal and nuclear electricity, synthetic fuels, and non-OPEC supplies of petroleum and natural gas are determined exogenously on the basis of projections available in the Bank and elsewhere. 1/ The long-run coal supply model is based on estimates of long-run production costs which are defined to be a function of cumulative production. In the major coal producing and exporting countries, long-run production costs are expected to increase only at 1-2% annually at the current rates of production. The model is used to examine the implications of various non-OPEC supply scenarios.

1/ A preliminary model of the non-OPEC supply of hydrocarbon fuels has been constructed. Simulations with the model pointed to the likelihood of a significant shortfall of petroleum supplies near the year 2000 below the base-case level specified exogenously. This supply model will be eventually incorporated into WEPM after further refinements.

The question of OPEC production and pricing has been the subject of intensive scrutiny since the first oil price shock of 1973/74. Earlier papers on the subject by Blitzer, et al. (1975), Cremer and Weitzman (1976) and Kalymon (1975) were critically surveyed by Fischer, Gately and Kyle (1975). Later studies were published by Pindyck (1978), Gately, Kyle and Fischer (1977), Hnilicza and Pindyck (1976), and a host of others. However, these analyses were overtaken by the second oil price shock of 1979/80. Despite the differences in methodology and assumptions, it was the general conclusion of the earlier models that the price of OPEC oil was not likely to increase much beyond its 1975 level, or at most increase gradually in the long run to a level substantially below its current level.

It is perhaps premature to pose the question, "What went wrong with the earlier models of OPEC pricing and production?" For one thing, the circumstances leading to the 1979-80 price increases were unforeseen. On the other hand, hindsight tells us that the earlier modelers and analysts were overly optimistic about the degree and speed of energy supply/demand adjustments to the first oil price increases. Contrary to earlier optimism, it became painfully clear that the supplies of petroleum and natural gas in North America, the most important traditional producing area, face a serious resource constraint. Non-conventional liquid fuel technologies have also been a major disappointment. Demand adjustments were slower than expected: significant adjustments came only after the second oil price shock.

WEPM represents an attempt to describe the energy markets in a more detailed and realistic way than the earlier models. As shown by Gately, Kyle and Fischer (1977), conclusions about OPEC pricing critically depend on the size of demand and supply elasticities. This pursuit of realism will be assisted by the hindsight of the last decade and advances made in recent years in empirical studies of energy demand and supply relationships.

The model was tested against the historical data of the 1970s. The performance of the model in simulating the 1970s was reasonably satisfactory. Total primary energy demand and sectoral final energy demand estimates were close to actual demand. Individual fuel demand estimates, based on the interfuel substitution functions, showed slight overestimation of the short-run interfuel substitution responses. The demand for natural gas was signi-

ficantly overestimated because of the unrealistic assumption of competitive equilibrium of the natural gas market. The anticipated deregulation of natural gas prices in the United States and elsewhere should substantially alleviate this difficulty for future projections work.

WEPM simulation results portend the following for the future of world energy balance and OPEC pricing. Under the base-case assumptions about GDP growth and the price of OPEC oil (assumed to increase gradually to $37 per barrel in 1990 and to $56 in the year 2000 in constant 1981 dollars), world primary energy demand is projected to increase at only 0.4% p.a. between 1978 and 1990 compared with the 2.9% p.a. growth experienced between 1970 and 1978; for the 1990s, the growth rate is projected at 2.4% p.a. About 43% of the incremental demand for primary energy between 1978 and the year 2000 is expected to come from the oil-importing developing countries, another 27% from the industrial countries, and the remaining 30% from the oil-exporting developing countries. Nevertheless, the oil-importing developing countries are projected to increase primary energy consumption at only 3.3% p.a. between 1978 and the year 2000, compared with 6.2% p.a. growth during 1970-78.

The model projects OPEC production of crude oil at 21.3 million b/d in 1982, compared with an estimated actual of 20-20.5 million b/d (without the stock drawdown). The base-case results suggest that for the next several years, world petroleum demand is not likely to exceed 45 million b/d; OPEC crude oil production is expected to hover around 21 million b/d, with net exports of petroleum at around 18-19 million b/d through 1985. These results suggest that in the short term the demand for OPEC crude oil will remain well below the productive capacity of OPEC. World demand for liquid fuels is not expected to rise beyond its 1978 level of 48.8 million b/d until 1995, then slightly exceed that level in the second half of the 1990s. World demand for liquid fuels is projected to increase to 52 million b/d by the year 2000; demand for OPEC oil is projected at 24.6 million b/d by 2000, still comfortably below the anticipated productive capacity of OPEC by that time.

Of the total incremental demand for primary energy between 1978 and the year 2000, about 10.5% is to be met by liquid fuels, 6.3% by natural gas, 62% by coal, and 21.2% by primary electricity. Interfuel substitution is seen to take place primarily in the movement from hydrocarbon fuels to coal

directly and indirectly through thermal electricity generation. The share of coal in total primary energy consumption is seen to increase from 20.2% in 1978 to 27.7% in 1990, and 30.6% in the year 2000. Of the total incremental demand for thermal coal between 1978 and the year 2000, about 53.4% is expected to come from the thermal power sector.

In brief, world demand for energy and petroleum is likely to remain at relatively low levels throughout the 1980s and most of the 1990s if OPEC follows the pricing path for its crude oil assumed in the base case. Past and expected petroleum price increases will provide a strong and sustained incentive to substitute away from energy and petroleum; enough to keep the demand for OPEC oil comfortably within OPEC's productive capacity. Coal will play a key role as a substitute fuel for the next 20 years.

Perhaps the most important source of uncertainty for the future development of energy markets is the uncertainty of economic growth. Under an assumption of 20% higher economic growth rates than the base case assumed for the 1985-2000 period, OPEC's production and exports increase significantly. World demand for energy is 13.3% higher, and world petroleum demand is 14.2% higher for the year 2000. This involves an increase of more than 30% in the demand for OPEC oil for the same year.

Another important source of uncertainty in projecting energy demand is the magnitude of the long-term price elasticities of final energy demand and interfuel substitution. A 20% reduction in the price elasticities of final energy demand results in a 10% increase in world primary energy demand and a 7.5% increase in world petroleum demand by the year 2000, while the demand for OPEC oil increases by almost 16% to 28.5 million b/d--a level still within the range of the likely OPEC productive capacity at that time. Lower interfuel substitution elasticities would cause the demand for OPEC oil to exceed this 28.5 million b/d figure by a substantial margin.

A significant shortfall in nuclear power supplies results in only a minor increase in the demand for petroleum; the shortfall is compensated largely (up to 88%) by an increase in coal-fired thermal power generation.

An interesting policy question is what the result might be if all oil-importing countries imposed a tariff on imports of petroleum. It could be expected that such an action would induce a counteraction by OPEC and the

eventual outcome would be hard to predict. The model can be used to calculate the first-round results of such a tariff. A 30% tariff on petroleum imports by the oil-importing countries reduces the world primary energy demand by 2.1% for the year 2000 compared with the base case; it would reduce world petroleum demand by 9% and the demand for OPEC oil by 18.6%. The tariff significantly increases the demand for natural gas, but increases the demand for coal only slightly.

The model is used to assess the relative merits, in terms of present value of export revenues and remaining reserves, of alternative long-term pricing paths that OPEC may consider. The model assumes that the demand for OPEC oil is price inelastic in the short run, close to unitary elasticity in the medium run, and moderately elastic in the long run. These elasticity values result in present values of OPEC export revenues that differ not substantially for the alternative pricing paths. Within reasonable variations of discount rates and price elasticities of final energy demands, the results show that the base-case pricing path yields generally higher revenues than other pricing options.

The above conclusions should be taken with caution. The lack of energy-economy feedback and non-OPEC supply responses in the model could have biased upwards the choice of the pricing path. Therefore, a pricing path somewhat more moderate than that of the base case probably would be close to the optimal long-term pricing path for OPEC.

A cyclical pricing path resembling actual price movements during the 1970s does not appear to be an attractive option for OPEC. In the wake of the second oil price shock of 1979/80, the opportunity for another substantial sudden price increase is not likely to arise during the 1980s unless the world economy grows at a substantially higher rate than the base case. A cyclical pricing strategy could make sense only if price increases are closely tied to demand increases.

OPEC as a whole is worse off by adopting a high pricing path, where the price of OPEC oil is quickly increased to the level of synthetic fuel costs and is maintained at that level for all subsequent years. The capital-deficit group, however, is better off by adopting this option, if its share of total OPEC production does not suffer as a consequence.

Revenues of the two OPEC subgroups show greater sensitivity to the choice of a production prorationing regime than to the choice of a pricing path. The best of all possible worlds for the capital-deficit group is higher prices and larger production shares for the period up to 2000. However, the group is better off by gaining a larger production share even if in return it has to yield to a relatively moderate pricing path. This strong incentive to gain a larger production share could trigger price competition between the OPEC groups to the point where both parties lose in the end. As with any oligopolistic cartel, production prorationing becomes the most critical issue once the cartel operates along an oligopolistic pricing path, a point which OPEC obviously has reached.

An assumption of lower final energy demand elasticities than those of the base case results in substantially higher revenues for OPEC, but the relative rankings of the alternative pricing paths do not change appreciably. Also critically important for OPEC revenues is economic growth in non-OPEC countries: 20% higher economic growth rates than the base case for the 1983-2000 period increase the present value of OPEC revenues by 12% on the average. However, it is the capital-surplus group of OPEC which benefits most from higher economic growth and/or lower energy demand adjustments in non-OPEC countries. This group would be more interested in fostering high economic growth than the capital-deficit group, even at the expense of somewhat lower prices for OPEC oil than what the latter group may prefer.

Imposition of a tariff on crude oil imports by the oil-importing countries would have an adverse impact on OPEC revenues and the value of reserves. A 30% tariff leads to a 17.2% reduction in the present value of OPEC exports. This implies that more than half of the tariff revenues of the oil-importing countries constitutes a resource transfer from the oil-exporting countries to the oil-importing countries. Within OPEC, the capital-surplus group suffers a more than proportional loss in export revenues.

The international price of thermal coal is expected to increase only slowly in line with increases in long-term costs of supply. This provides a strong incentive to substitute coal for petroleum, leading to rapid increases in international trade in thermal coal. Net coal exports from North America, which reached 98 mtce in 1981, are projected to increase to 650 mtce by the year 2000. Western Europe is projected to increase net coal imports from 88 mtce in 1980 to 400 mtce by the year 2000.

Annex 1.1

COUNTRY GROUPS IN WEPM

Group Number	Group Symbol	Countries Included in the Group
1	NOAM	United States, Canada
2	WEUR	European members of OECD except Spain, Greece, Portugal and Turkey.
3	JANZ	Japan, Australia, New Zealand
4	CSEX	Iran, Iraq, Libya, Kuwait, Oman, Qatar, Saudi Arabia, UAR
5	CDOP	Algeria, Ecuador, Gabon, Indonesia, Nigeria, Venezuela.
6	NOEX	Angola, Bahrain, Bolivia, Brunei, Congo, Egypt, Malaysia, Mexico, Syria, Trinidad and Tobago, Tunisia, Zaire
7	OIDC	All countries in the world excluding the groups 1-6 above and the centrally planned economies.
Centrally Planned Economies		Albania, Bulgaria, Czechoslovakia, Germany, D.R., Hungary, Poland, Romania, USSR. Cuba, Dem. Kampuchea, Laos, Vietnam, Korea, D.P.R., Mongolia, China, P.R.

II. THE MODEL STRUCTURE

WEPM consists of a system of equations and commands written in the Research Analysis Language (RAL) and a data file containing the historical observations and parameters. The model is divided into five blocks. The demand block calculates the demands for fuels by sectors under given energy prices and income growth. The supply block exogenously specifies the available supplies of hydrocarbons, hydro/nuclear electricity and synthetic fuels in addition to calculating the supplies of coal as a function of coal prices. The price block computes the end-user prices of energy under assumptions about the OPEC crude oil prices, domestic price controls and taxes. The OPEC block calculates the present value of OPEC revenues under assumptions about OPEC production prorationing. The main block links the other blocks together and performs the iterations to find the equilibrium solution.

The purpose of this chapter is to show the interrelationships between energy markets and how they are dealt with in the model. Since energy prices provide the linkages connecting various energy markets, an explanation of how energy prices are determined in the model will clarify the interrelationships between energy markets. We begin with the role of OPEC in the international petroleum market (OPEC block), and move on to the determination of energy prices in various markets (price block and main block). The demand and supply issues are the subjects of the next two chapters.

2.1 OPEC and World Energy Markets

OPEC has been variously described as a monopolistic cartel, 1/ a dominant oligopolistic cartel consisting of two or three distinct groups, or

---

1/ A cartel is defined as a collective body which sets the price of its product above the competitive level by restricting the supplies of its members.

even as a group of competitive producers. 1/ Following the majority view, OPEC is treated here as a dominant oligopolistic cartel, which sets the world market price of crude oil and adjusts its production accordingly. The non-OPEC producers of petroleum act competitively, taking the OPEC determined price as given. OPEC thus becomes the residual supplier to the world market. There were occasions when OPEC appeared to follow market determined prices. It should be remembered, however, that OPEC, jointly or individually, has restricted its supplies below the maximum sustainable capacity since the first oil price shock of 1973/74.

Understanding and modeling the behavior of an oligopolistic cartel has been one of the most intractable problems in economic theory. WEPM does not have an explicit model of OPEC's oligopolistic behavior that would lead to a specific solution of the OPEC pricing and production problem. 2/ The

---

1/ See, for example, J. Cremer and D. Salehi (1980), "A Theory of Competitive Pricing in the Oil Market: What Does OPEC Really Do?." In addition, Philip Verleger writes, "OPEC has managed to manipulate the price of oil not by reducing output, but by responding slowly to market conditions." See "Volcker Versus Yamani: Oil Prices in Decline," in Energy at Booz Allen, Vol. 4, No. 1, Winter 1982, p. 4.

2/ Hnyilicza and Pindyck (1976) modeled OPEC as a two-part exhaustible resource cartel and investigated the optimal pricing and production paths, using the framework of Nash's two-person cooperative games. The findings were surprising in that the optimal solution calls for one group (the capital-surplus oil exporters) not to produce at all until the other group (the capital-deficit OPEC countries) completely exhausts its petroleum resource. This outcome is clearly unrealistic, but it is indicative of the underlying economic forces. Kuenne (1979) developed perhaps the most realistic model of OPEC behavior, where OPEC is viewed as a community of simultaneously competing and cooperating rivals, each following its own strategies that reflect its perception of the industry power structure. He molds this line of approach in a modified non-linear programming format called "crippled optimization". Each rival maximizes a joint welfare function consisting of its own profits and the profits of its rivals discounted by a power structure discount factor, under a set of constraints containing subordinate objectives and perceived restraints. His results for the short run closely replicate the market developments during 1979/80; OPEC members would agree on the price of the marker crude at around $30, which is not substantially higher than what would prevail if OPEC members had acted individually, nor significantly lower than if OPEC had acted as a monopolist. The African producers and Iraq would be inclined to charge higher premiums--as they actually did--and opt to produce less than otherwise. Although very illuminating of the short-term behavior of OPEC, Kuenne's model has yet to be extended to incorporate the members' long-term economic considerations which could tell us more about the nature of OPEC rivalry and cooperation in the long run.

approach here is to confront OPEC with a menu of pricing, production, and revenue paths, and discuss OPEC's choice among them on the basis of the perceived economic interests of its members. Although this approach does not yield the optimal solution to OPEC's problem, it has the advantage of permitting detailed description of market structure and easy experimentation with various uncertainties of the market.

It is assumed that OPEC's criterion for evaluating alternative pricing paths, either jointly or individually, is the discounted present value of export revenues, i.e.:

$$\text{Maximize } W = \sum_{t=1}^{T} \frac{P_t \; Q_t}{(1+r)^t} , \qquad (2.1)$$

where P_t is the export price of OPEC petroleum in year t and Q_t is the export quantity. The time rate of discount of future revenues is represented by r. T is the year when reserves are exhausted. OPEC would be interested in maximizing net revenues (price minus production cost) rather than gross revenues as postulated above. For the lack of adequate information on production costs, we make the simple assumption that production costs will remain constant. 1/

To evaluate W in (2.1), we need to know P_t's and Q_t's beyond the year 2000 because OPEC's petroleum resources are not likely to be exhausted by that time. Following Nordhaus (1973), we rely on the notion that the price of petroleum will be constrained in the long run by the availability of "backstop" technologies--practically unlimited sources of supplies of substitutes for petroleum at constant costs. The economic theory of exhaustible resources tells us that the price of petroleum cannot exceed the cost of backstop supplies and an oligoplist will maximize revenues over time by having some reserves left on the day a backstop technology is introduced, even if the

---

1/ Theoretical literature on the production of exhaustible resources under increasing costs of extraction--for example, Solow and Wan (1976), Heal (1976), and Dasgupta and Heal (1979)--has suggested that optimality requires higher prices and lower production in the immediate future than in the case of constant production costs.

remaining reserves have to be sold at a constant price. 1/ To calculate W for the years beyond 2000, it is assumed that the price of OPEC oil will gradually reach the level of backstop costs and remain at that level for all subsequent years. Q_t's for the years beyond 2000 are calculated using the price and income elasticities of the demand for OPEC oil implicit in the model. 2/

The backstop technologies for liquid fuel supplies are still elusive. Possible candidates in various stages of development are liquid fuels from shale oil, tar sands and coal liquifaction, but estimates of their costs have been escalating throughout the recent years. Backstop supplies and costs are treated as uncertain quantities in this paper. We assume for the base case that the cost of backstop supplies will be about $56 per boe (in constant 1981 dollars), and about 4.8 mbdoe will be supplied from these sources by the year 2000. The level of backstop costs and the date of their arrival will have a fairly predictable impact on the optimal OPEC production and pricing path. For example, the higher the cost of backstop supplies, the higher the optimal pricing path for OPEC. A further delay in the introduction of backstop supplies would cause OPEC to restrict production and charge higher prices.

It has been well recognized that the OPEC countries have widely different economic interests with regard to their petroleum resource extraction and pricing. Short of modeling OPEC's oligopolistic behavior, we need to look at OPEC's pricing decision from the perspective of individual countries or at least some groups of countries.

The model distinguishes broadly two groups of countries within OPEC. The most important factor that differentiates OPEC members with regard to the pricing issue is the size of their resource base and the level of annual production *vis-a-vis* their revenue needs. Table 2.1 shows the proven

---

1/ For a succinct discussion of this subject, see Chapter 6 of Dasgupta and Heal (1979). Under competitive conditions, the resource will be depleted on the day the backstop supplies are introduced and the price reaches the level of backstop costs.

2/ See section 5.4 for estimates of these elasticities.

Table 2.1: OPEC PETROLEUM PRODUCTION AND RESERVES
(billions of barrels)

	Proven Reserves at End of 1978 (A)	Production in 1978 (B)	Cumulative Production to End of 1978 (C)	Reserve Production Ratio A/B	A/A+C
Capital-Deficit Group					
Algeria	11.59	0.44	5.60	26.3	0.67
Ecuador	1.11	0.08	0.54	13.9	0.67
Gabon	0.60	0.08	0.74	7.5	0.45
Indonesia	9.82	0.60	8.17	16.4	0.55
Nigeria	12.27	0.70	6.81	17.5	0.64
Venezuela	18.23	0.79	34.39	23.1	0.35
Subtotal	53.62	2.69	56.25	20.9	0.49
Capital-Surplus Group					
Iran	44.97	1.88	28.34	23.9	0.61
Iraq	34.39	0.93	13.59	36.9	0.72
Kuwait /a	74.60	0.78	20.46	95.6	0.78
Libya	27.20	0.72	11.38	37.8	0.71
Qatar	3.85	0.18	2.83	21.4	0.58
Saudi Arabia /a	170.27	3.03	35.20	56.2	0.83
UAE	31.58	0.66	5.89	47.8	0.84
Subtotal	386.86	8.18	117.69	47.3	0.77
Grand Total	440.48	10.87	173.94	40.5	0.72

/a Including half of the neutral zone production and reserves.

Source: World Oil, August 15, 1980.

reserves, cumulative production and the reserve/production ratios of petroleum of OPEC countries. The reserve/production ratio is an indication of the likely longevity of proven reserves. The ratio of current proven reserves to cumulative proven reserves (current proven reserves plus cumulative production) can be taken as an indication of the degree of resource exhaustion. The countries included in the capital-surplus oil-exporting group have reserve/production ratios of over 30 years and/or are deemed to have large undiscovered resources. The remaining countries in OPEC--the capital-deficit OPEC group--are generally characterized by relatively low reserve/production ratios and limited potential for additional discoveries. This distinction, although common in the existing studies of the petroleum market, is bound to have some degree of arbitrariness. Examples are Iran, Iraq and Libya, which often identified themselves with the interests of the capital-deficit group. These countries, however, have relatively high reserve/production ratios and the potential for large undiscovered resources, and hence are included in the capital-surplus group.

The conflicting economic interests of the two OPEC groups are reflected in the model in two ways. One is the problem of allocating the total OPEC production of crude oil betwen the two groups. The other is the choice of an appropriate discount rate for each group for evaluation of its revenue stream.

Production prorationing is the most difficult problem facing any cartel, and OPEC is not an exception. The model experiments with alternative prorationing regimes to find their long-term revenue implications. Table 2.2 shows three alternative prorationing regimes that are designed to cover the range of possibilities.

The most simple solution to the prorationing problem is to continue the present production shares until the reserves run out for one of the groups (regime A). The production shares have in fact shown a reasonable degree of stability over a number of years. The constant-share case, however, may not be economically efficient from the point of view of OPEC as a whole, as shown by Hnyilicza and Pindyck (1976). The regime B assumes that the share of the capital-deficit group would be maintained at a relatively high level in the 1980s and gradually decline as reserves are depleted.

Table 2.2: ALTERNATIVE OPEC PRODUCTION SHARES /a

Prorationing Regimes	1978	1980	1985	1990	1995	2000
A	75	72	75	75	75	75
B	75	72	60	60	70	90
C	75	72	80	80	70	70

/a Percent share of the capital-surplus oil-exporting countries in total OPEC production.

Source: World Bank, Economic Analysis and Projections Department.

In an effort to push for higher prices, the capital-deficit group may wish to charge premiums for their crudes and as a consequence lose some of its market share. The capital-surplus group would respond by increasing production in order to bring down the price to a level compatible with its long-term interests. This type of behavior is essentially of a short-run nature; both parties will eventually vie for a greater share of the market. However, because of inertia and market inflexibilities, the capital-deficit group in the medium run may produce a share of OPEC production which is less than in the case when they did not take such an action. This possibility is described by the regime C.

Fundamental differences among OPEC members in terms of economic development and revenue needs mean differences in the discount rate. A single discount rate applied to OPEC as a whole and for all future years is clearly unrealistic, and could seriously bias the conclusions. 1/

In an attempt to account in part for the diversity and variability of discount rates, we assume that the portion of revenues needed to pay for

1/ Under conditions of smoothly functioning capital markets, Koopmans, Diamond and Williamson (1964) have shown the possibility of variable discount rates not only over time but also across countries.

imports should be discounted at a higher rate than surplus revenues that are invested in the international capital market. To do this, the import demand (IM) for each OPEC group is projected by:

$$IM_t = IM_0 \ (GDP_t/GDP_0) \ . \tag{2.3}$$

Then, the surplus revenues (SR) are:

$$SR_t = P_t Q_t - IM_t, \ \text{if} \ IM_t \leq P_t \ Q_t. \tag{2.4}$$

The criterion function is now redefined as:

$$\text{Maximize } W = \sum_{t=1}^{T} IM_t/(1 + r_m)^t + \sum_{t=1}^{T} SR_t/(1 + r_s)^t \tag{2.5}$$

where r_m and r_s are the discount rates for imports and surplus revenues, respectively.

2.2 Interrelationship of Energy Markets

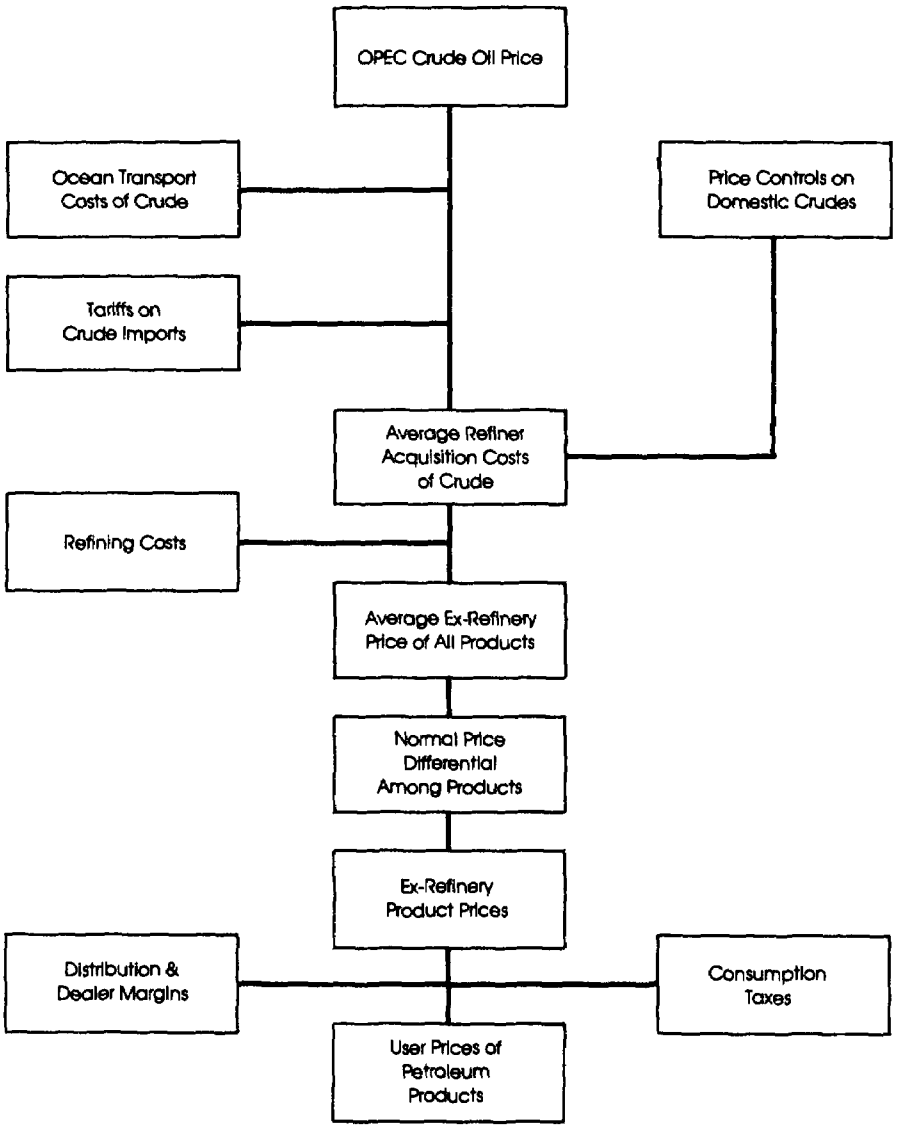
Petroleum Market and Product Pricing

The mechanism through which the prices of crude oil and petroleum products are determined is shown schematically in Figure 2.1. OPEC determines the international market price of crude oil, which is treated as a homogeneous product represented by the Saudi Arabian marker crude. The price of crude oil at the domestic market level is determined by price controls and taxes on crude oil in individual countries.

For the sake of simplicity, WEPM assumes that the prices of petroleum products will maintain a certain fixed relationship to the price of crude petroleum, in both the international and domestic markets for petroleum products. 1/

1/ To build a model which allows for various petroleum product markets would require an explicit description of the availability of crude petroleum of different qualities and the refining technology, in addition to the elements incorporated in WEPM. This would require much additional information and would significantly add to the complexity of the model.

Figure 2.1
Schema for Determination of Crude Oil and Petroleum Product Prices



World Bank--24531

It is acknowledged that the assumption of fixed product price differentials is likely to be an unrealistic one. Ex-refinery product price differentials at the domestic market level often deviate substantially from the corresponding international product prices, with much of the difference resulting from implicit tax or subsidization policies of individual countries. Moreover, different petroleum products serve different energy markets and face different competing fuels. For example, it has been widely conjectured that the light petroleum products used for transportation and chemical feedstock will become more expensive relative to heavy petroleum products used mostly for thermal combustion--where competition is with cheaper coal. The use of fixed product price differentials, therefore, would overestimate the price of heavy fuel oil and bias the results in favor of coal in relation to oil in the markets where the two fuels compete.

Determining the ex-refinery product price differentials for the recent historical period is not an easy task. The ex-refinery price for each product is calculated by subtracting taxes and normal distributors' margins from the price paid by final users. Table 2.3 shows the three-year average (1976-78) differentials for the seven regions of WEPM and for the Rotterdam product prices as representative of the international product market.

Ocean transportation costs of crude oil, refining costs, dealer margins, and distribution costs are calculated on the basis of 1976-78 averages and held constant in real terms for all future years. This assumption appears reasonable because there are no apparent reasons to expect a long-term trend in these variables, and because the industries involved are basically competitive.

Apart from price controls, important policy variables in the petroleum price chain are the tariffs on crude oil imports and taxes on petroleum products. Tariffs on crude oil, not yet adopted extensively, would raise the product prices across the board, while taxes are specific to a product. Taxes and tariffs are a part of the pricing package. By changing these variables, it is possible to find the implications of different pricing policies of oil-importing countries for OPEC pricing and production.

Table 2.3: EX-REFINERY PRODUCT PRICE DIFFERENTIALS FOR WORLD REGIONS AND THE INTERNATIONAL PRODUCT MARKET /a

(Weighted average ex-refinery price of all products = 1.0)

	Gasoline	Diesel Oil	Jet Fuel/ Kerosene	Light Fuel Oil	Heavy Fuel Oil
Rotterdam Market	1.08	1.03	1.14	1.03	0.72
World Regions /b					
NOAM	1.03	1.03	1.14	1.00	0.74
WEUR	1.33	1.24	0.91	0.94	0.61
JANZ	1.61	1.34	1.26	0.61	0.87
CSEX	3.08	0.62	0.92	0.46	0.15
CDOP	1.20	1.10	0.60	0.80	1.00
NOEX	1.77	0.62	0.31	0.54	0.05
OIDC	1.76	1.12	1.06	1.15	0.58

/a Based on three year averages (1976-78).
/b For the regional classification, see Annex 1.1.

Source: See Annex 3.1, Data Sources and Limitations.

Relationships between Energy Markets

Determination of the relative fuel prices through interactions between energy markets is a complicated process in which both supply and demand forces are brought into play. On the demand side, a switch from one fuel to another is affected not only by their relative prices, but also by the associated costs of capital renovation or replacement, governmental restrictions on the use of certain fuels because of environmental reasons, technological inflexibilities of substitution, and others. On the supply side, each of the four primary energy sources have a widely different resource base and industrial structure, and the degree of government intervention also varies widely.

The international market price of natural gas (CIF basis, major importing regions) is assumed to maintain a near parity with the price of

petroleum products in the same market, on the ground that they are close substitutes in consumption and, moreover, the potential exporters of natural gas are almost identical to the petroleum exporters. If these countries (essentially OPEC) price natural gas at a substantially lower level than that of petroleum, natural gas trade could expand to such an extent as to undermine their own petroleum market.

At the domestic level, the natural gas industry has been subjected to a greater degree of government controls than the petroleum industry and the price of domestically produced natural gas on an equivalent BTU basis has been suppressed substantially below the prices of competing petroleum products. In the United States and Western Europe, the price of natural gas is also bound by long-term contracts that were negotiated before the 1973/74 oil price increase. The price controls and long-term contracts are expected to be phased out, but their future course is uncertain even in countries that have legislated decontrol programs. It is assumed that the price of domestically produced natural gas depends entirely on the future course of decontrol policies and long-term contracts; we make several different assumptions about their future for the simulation exercises.

If the relative fuel prices are such that the demand for natural gas in a non-OPEC region falls below the exogenously specified supplies of natural gas in the region, it is assumed that the excess supply availabilities will not materialize instead of putting downward pressure on the price of natural gas. If the demand for natural gas exceeds the available domestic supplies, it is assumed that the difference will be imported from OPEC, which acts as the residual supplier of natural gas to the world market. OPEC's net exports of natural gas are divided between the two OPEC groups in proportion to their export potential, which is specified exogenously.

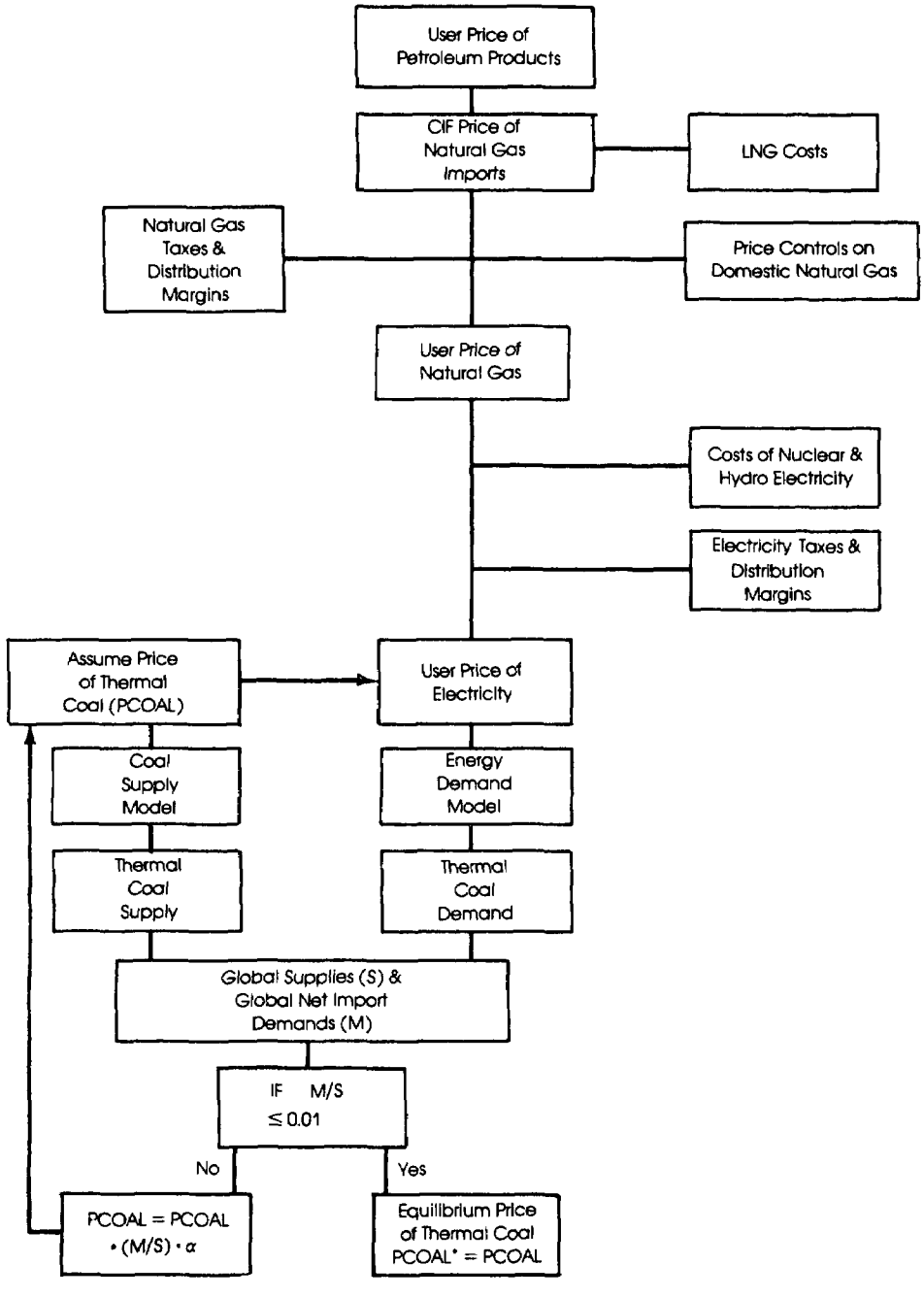
The electricity industry is another example of a heavily regulated public utility. Pricing of electricity in almost all countries is based on average costs, although this general principle is applied in a number of different ways to different end-users in different countries. For the sake of simplicity, it is assumed that the price of electricity will be determined for all end-use sectors in all regions by the average cost of electricity generation plus the transmission and distribution costs. The thermal power industry

is assumed to choose the optimal fuel mix to minimize the total cost of thermal electricity generation. The demand for thermal electricity is determined as a residual, i.e., total demand for electricity minus production of primary electricity (consisting of hydro and nuclear power generation). The costs of hydro and nuclear electricity generation are estimated for each region on the basis of investment costs for the planned capacity expansion projects in the 1980s. The average cost of electricity is the weighted average of the costs of thermal and primary electricity. The costs of transmission and distribution are estimated from 1976-78 data and are assumed to remain constant in real terms for all future years.

Of all energy prices, a competitive equilibrium solution is sought only for the domestic and international market prices of thermal coal. The assumption of competitive equilibrium implies that the export prices of thermal coal (FOB export terminals) will be equalized across the major coal exporting countries, after allowance for differences in coal quality and costs of international shipping. The US export price (FOB Atlantic coast) is chosen as the indicator of the international price. Thus, if the US export price increases by US$10 to clear the international market, the export prices of other coal exporting countries also increases by the same amount. A coal exporting country will be able to expand its share of world coal exports if its production costs increase at a slower rate than other coal exporting countries. The competitive equilibrium assumption also implies that the domestic price of coal in a coal exporting country such as the United States should equal the export price minus the cost of bringing coal to the export terminal.

Determination of prices and quantities of all energy products is shown schematically in Figure 2.2. The price of OPEC petroleum and domestic pricing policies of individual countries determine the prices of all petroleum products to the final users. The import price of natural gas is assumed to maintain a certain relationship to the price of petroleum products, while the price of domestically produced natural gas is determined by price control policies of individual countries. To arrive at a competitive solution for the price of thermal coal, an iterative procedure is used. It starts from a certain set of prices for thermal coal--for example, the prices in the previous year. Since the prices of all fossil fuels are now given, it is

Figure 2.2: Energy Market Interactions and Determination of Equilibrium Prices



World Bank—24915

possible to calculate the cost of thermal electricity and hence the average price of all electricity, given the exogenously determined costs of primary electricity. From the energy product prices thus determined, it is possible to calculate, under a given assumption about GDP growth, the excess demand or supply quantities for all fuels by regions, including those of thermal coal. Regional imbalances of thermal coal supply and demand give rise to international trade, and if there is global excess demand (supply), the international export prices and the FOB mine prices are raised (reduced) by a certain fraction of the percentage of global excess demand (supply) to global total demand. The same computation is repeated with the new set of thermal coal prices until the coal market is cleared. Global supply and demand equilibrium for petroleum and natural gas is fulfilled by assuming that OPEC will supply net import demands from non-OPEC regions. The supply/demand equilibrium for electricity is achieved by assuming that the thermal power industry will fill the gap between total electricity demand and available supplies of primary electricity. Electricity is treated as a non-tradable good.

III. MODELING THE DEMAND FOR ENERGY

Although the demand for energy has been subjected to extensive analyses and modeling in recent years, some important controversial issues still remain. These issues are mainly concerned with the magnitude of energy demand adjustments to changing income and energy prices. The studies by Griffin (1979) and Pindyck (1979) for the industrial countries contain excellent summaries of these issues together with econometric estimates of income and price elasticities of energy demand.

In view of the already extensive analyses of available data, the demand model in WEPM is structured to be able to experiment with the range of existing findings. The methodology and the demand equations are the standard ones found in the literature. In the following sections, we first take a methodological overview and then go into the details of the main energy-consuming sectors--the transportation, industrial and residential/commercial sectors and the energy transformation sector. An annex to this chapter describes the data sources and data limitations.

3.1 A Methodological Overview

The predominant approach to global energy demand modeling has been through the use of econometric models based on historical data. There have been two important issues in the econometric estimation of energy demand responses. One of them has to do with the kind of historical data used for estimation, i.e., time-series data versus pooled international cross-sectional, time-series data. This is an important difference because it leads to substantially different estimates of the size of demand adjustments. Earlier time-series estimates of energy demand--for example, by Berndt and Wood (1975), Houthakker and Verleger (1973) and Fuss (1977)--have been criticized for lacking enough variance in the price variable to elicit long-term responses. Griffin (1979) and Pindyck (1979) argue strongly that the cross-country variations in energy prices and energy consumption are likely to yield results more representative of long-term demand adjustments than time-series data alone. Indeed, the long-run price elasticity estimates obtained

from pooled international cross-sectional, time-series data are about twice as large as the estimates obtained from time series alone. WEPM for the most part uses the international cross-sectional, time-series estimates. In addition to the Griffin/Pindyck arguments in favor of this approach, energy demand adjustments that took place in recent years strongly suggest that typical time-series evidence indeed leads to a serious underestimation of demand adjustments to higher prices.

Related to the time series versus cross section issue is the problem of the dynamics of energy demand adjustments. Energy invariably is consumed in conjunction with utilization of capital stock. Because of this, changes in the energy price can affect energy demand through: (a) adjustment of the utilization rate of the capital stock; (b) modification of the energy efficiency of the existing capital stock; and (c) replacement of the existing capital stock. The dynamic path of adjustment in energy demand from the short run to the long run depends on the relative magnitude of the three types of adjustments at each point in time. A priori, one would expect that the adjustment of the capacity utilization rate would occur mostly in the short run and quickly taper off as time passes. Replacement of capital stock can be achieved only over a long period of time. The time needed for retrofitting the existing capital stock will fall somewhere between the two extremes. The relative magnitudes of the three types of adjustments are expected to vary substantially across the energy-consuming sectors.

There have been broadly three different aproaches to estimation of the dynamics of energy demand adjustments. A common approach--e.g., Pindyck (1979)--has been the use of geometric distributed lags, which assumes that the initial impact of a price change is the greatest and the impact diminishes geometrically over time. This formulation is too restrictive in view of the foregoing discussion. The second and more general approach is to use the polynomial distributed lag, which does not put prior restrictions on the shape of the dynamic path. According to this approach, energy demand equations for final consumption sectors take the form:

$$\ln(E_t) = \alpha + \beta \ln(Y_t) + \gamma \sum_{j=1}^{k} \lambda_j \ln(P_{t-j+1}), \qquad (3.1)$$

where E_t is the energy demand in year t, Y_t is the real value-added (income), P_t is the real price of energy, and β is the income elasticity of energy demand. The dynamic path of adjustment is expressed by the λ's, which can take any desired shape. Note that $\gamma\ \lambda_1$ is the short-run (one year) price elasticity and γ is the long-run price elasticity when full adjustment has taken place. By definition, $\sum_{j=1}^{k} \lambda_j = 1$. Also note that adjustment to a change in income is assumed to be instantaneous, whereas in geometric models adjustments to changes in income and price follow the same dynamic path.

Specification of the dynamics of interfuel substitution poses more difficulties than that of final energy demand. The translog cost share model of interfuel substitution, used in WEPM as well as other studies including those of Griffin and Pindyck, takes the form:

$$S_i = \alpha_i + \sum_{j=1}^{4} \beta_{ij}\ \ln (P_j), \quad i,j=1,\ldots, 4 \tag{3.2}$$

where S_i is the cost share of the i-th fuel, P_j is the price of the j-th fuel, and α_i's and β_{ij}'s are parameters. It is assumed that there are four fuel types involved. This relationship is derived from static competitive cost minimization under a translog cost function. 1/ To transform this static equation into a dynamic one, an ad hoc method used by Griffin is to apply a polynomial lag operator to the β_{ij}'s. Thus, the equation (3.2) now becomes:

$$S_{it} = \alpha_i + \sum_{j=1}^{4} \beta_{ij} \sum_{\tau=1}^{k} \omega_\tau\ \ln (P_{j,t-\tau+1}), \tag{3.3}$$

where ω_τ's represent the polynomial lag structure stretching over k years.

The above ad hoc dynamization procedure, however, is not flexible enough to accommodate the kind of interfuel adjustment path one would expect in view of the short-run inflexibility of fuel switching. More specifically, Griffin (1979) and Berndt, Fuss and Waverman (1977) showed that the translog cost share model results in short-run own- and cross-price elasticities that

---

1/ For a complete description of the translog cost share model, see Griffin (1979), pp. 47-64.

are unduly large compared with their long-run counterparts. The own- and cross-price elasticities of the demand for individual fuels in (3.2) are: 1/

$$\xi_{ii} = (\beta_{ii}/S_i) + S_i - 1,$$
$$\xi_{ij} = (\beta_{ij}/S_i) + S_j, \quad i \neq j. \tag{3.4}$$

A numerical example best illustrates the problem. Suppose that the cost share of oil is 60% and β_{ii} for oil is -0.1. Then, the long-run own-price elasticity of oil demand is

$$\frac{-0.1}{0.6} + 0.6 - 1 = -0.57.$$

Suppose $\omega_i = 0.05$. Then, the short-run own price elasticity would be

$$\frac{-0.1 \times 0.05}{0.6} + 0.6 - 1 = -0.41.$$

The elasticities are heavily dependant on the cost shares and reasonable variations in ω_i's make only minor differences. The procedure results in short-run overadjustments. The long-run fuel shares would not be affected by this problem, however.

The geometric and polynomial lag models are not based on explicit dynamic models of factor demand, but a rather ad hoc improvisations. A third and theoretically more rigorous approach is the dynamic factor demand models developed by Berndt, Fuss and Waverman (1977) and Epstein and Denny (1981). Their models have yet to be refined in several important directions before they become a realistic description of the adjustment mechanism. 2/

WEPM uses the polynomial lag structure despite the difficulties mentioned above. For a relatively large scale model as WEPM, this approach is perhaps the best one can adopt at this time. As shown in Griffin (1979),

---

1/ For a derivation of these elasticity formulas, see Berndt and Wood (1975). They are partial elasticities, i.e., the price elasticity of fuel demand, holding total fuel consumption constant.

2/ Empirical results with the model show disproportionately large estimates for the short-run price elasticity compared to those for the long run. Static expectations has been a standard assumption in these models, and ex ante and ex post substitution possibilities have not been distinguished.

estimation of the polynomial lag structure with historical data has so far had only limited success. However, the estimation errors involved are likely to be less serious than the specification error in the geometric lag formulation.

3.2 Transportation Demand for Energy

The transportation sector typically accounts for 15 to 30 percent of total final energy consumption and has been the fastest growing among the final consumption sectors. This section considers the response of transportation energy demand to income growth and drastically increased petroleum prices. Four types of responses to higher petroleum prices are possible: (a) reduce the amount of travel: (b) increase the efficiency of transportation; (c) switch the mode of transportation; and (d) substitute cheaper fuels for petroleum. Demand modeling in this area, however, has not yet reached the stage where the whole transportation system is analyzed simultaneously so that intermodal shifts can be taken into account. Instead, each transportation mode is modeled separately, with the expectation that the price term in each of them will capture most of the effects of modal shifts. Interfuel substitution is not likely to be important in the case of transportation energy consumption. The focus, therefore, will be on the responses (a) and (b) above.

Demand for Gasoline

About 25% of world petroleum or 15% of world primary energy is consumed in the form of gasoline. With rising income, the demand for passenger travel and hence the number of cars and gasoline consumption increased rapidly over the past two decades. As late as the 1973-78 period, the number of registered automobiles increased at an annual rate of 4% in the industrial countries and 10.5% in the oil-importing developing countries. Consumption of gasoline did not increase as rapidly as the number of cars, because the utilization rate declined as the number of cars increased, and the fuel efficiency of cars improved in recent years as the price of gasoline increased. Important statistics are shown in Table 3.1.

The gasoline demand model below follows the lines taken by Griffin (1979), Pindyck (1979) and Sweeney (1978). By definition, consumption of gasoline (GAS) can be expressed as:

Table 3.1: WORLD GASOLINE CONSUMPTION

Regions	Gasoline Consumption		Passenger Cars		Gasoline Consumption per Car	
	1978 Level (MBDOE)	Growth Rate (%) 1968-78(A)	1978 Level (Million)	Growth Rate (%) 1968-78(B)	1978 Level (Gallon/Day)	Rate of Change 1968-78 (A-B)
NOAM	7.66	3.82	127.1	3.53	2.53	0.29
WEUR	1.95	5.10	89.9	5.48	0.91	-0.38
JANZ	0.93	8.09	29.8	12.09	1.31	-4.00
Industrial Countries	10.54	4.36	246.8	4.96	1.79	-0.60
CSEX	0.14	13.52	2.3	16.76	2.56	-3.24
CDOP	0.23	8.84	2.7	11.65	3.58	-2.81
NOEX	0.34	7.63	4.5	10.58	3.17	-2.95
OIDC	1.26	4.92	31.7	11.32	1.67	-6.40
Developing Countries	1.97	6.30	41.2	11.48	2.01	-5.18
WORLD TOTAL	12.51	4.53	288.0	5.67	1.82	-1.14

Source: United Nations, World Energy Supplies and Statistical Yearbook, various issues, and OECD/IEA, Energy Statistics, various issues.

$$GAS = CAR \cdot EFF \cdot UTL, \tag{3.5}$$

where CAR is the number of cars in stock, EFF is the average gasoline consumption per mile and UTL is the miles driven per car. The gasoline demand model consists of two equations: one explains the demand for cars and the other explains gasoline consumption per car (GAS/CAR = EFF·UTL).

The number of registered passenger cars per capita (CAR/POP) is assumed to be a loglinear function of real per capita income (GDP/POP) and the real price of gasoline (PGAS) of the following form:

$$\ln\left(\frac{CAR}{POP}\right) = \alpha_0 + \alpha_1 \ln\left(\frac{GDP}{POP}\right) + \alpha_2 \ln\left(\frac{GDP}{POP}\right)^2 + \alpha_3 \sum_{j=1}^{k} \omega_j \ln\left(PGAS_{t-j+1}\right). \tag{3.6}$$

The price of gasoline is used as a proxy for the total user cost of cars, which includes, in addition to the cost of gasoline, the purchase price of the car and the costs of maintenance and insurance. Its coefficient (α_3), therefore, should be interpreted accordingly. The squared per capita income term partially takes account of the saturation effect on car ownership. At a relatively low level of per capita income, car ownership has shown high income elasticity, but relatively low income elasticity in a high per capita income region such as North America (see Table 3.1 for a broad indication of this).

Sweeney's (1978) model of demand for new cars in the United States explains sales of new cars by per capita income, unemployment rate, price of cars, stock of existing cars, per capita demand for vehicle miles, and other user cost items. His estimation results from the US time-series data indicate that the income elasticity of new car demand exceeds 3.0. Pindyck (1979) on the other hand found a long-run income elasticity of new car demand of only 0.3 from cross-sectional, time-series analysis of industrial countries. Estimation of total car stock demand from equations such as (3.6) has shown more stable results. Griffin (1979), for example, obtained estimate of 1.0 for the United States and 1.6 for the United Kingdom for the income elasticity of total car stock demand from cross-sectional, time-series data of industrial countries. This result is in line with that obtained by Burright and Enns

Table 3.2: CAR DEMAND PARAMETERS

Regions	α_1	α_2	α_3	Income Elasticity a/ 1978	2000
NOAM	1.74	-0.24	-0.10	0.7	0.49
WEUR	1.69	-0.24	-0.10	0.8	0.58
JANZ	1.88	-0.24	-0.10	1.0	0.69
CSEX	2.34	-0.24	-0.10	1.8	1.63
CDOP	1.26	-0.24	-0.10	1.5	1.28
NOEX	1.38	-0.24	-0.10	1.5	1.23
OIDC	1.24	-0.24	-0.10	1.5	1.25

Memo Item: Lag Structure

$\omega_1 = 0.4$, $\omega_2 = 0.3$, $\omega_3 = 0.2$, $\omega_4 = 0.1$

a/ Equation (3.6) implies the following relationship for the income elasticity of the demand for passenger cars ($\varepsilon_{CAR.Y}$):

$$\varepsilon_{CAR.Y} = \alpha_1 + 2 \quad \alpha_2 \ln \left(\frac{GDP}{POP}\right).$$

(1975) for the United States. Table 3.2 shows the parameters assumed for the car demand equation. The parameters assumed for the industrial countries are generally in line with the evidence from the latter group of studies, except that we chose slightly lower estimates for future projection than those obtained from data for the 1960s and early 1970s. For the developing countries, the parameters for the income effect are kept at relatively high levels to reflect the high growth rates of car purchases vis-a-vis income growth observed during the 1970s.

The impact of gasoline price on the stock of cars has largely been assumed. Available estimates using the user cost variable generally found elasticities in the range of -0.3 to -0.6. We purposely chose a low estimate on the ground that the price of gasoline is only a small part (about 20%) of the total user cost. The dynamic path is assumed to be rather short and to follow the geometric pattern.

Gasoline consumption per car is determined by the average fuel efficiency of cars and the utilization rate (mileage driven per car per

year). The average fuel efficiency depends on the characteristics of the automobile stock: car weight, engine and body design, and so forth. Consumers' choice of fuel efficiency characteristics of automobiles is largely determined by the price of gasoline. The per capita income variable could have a negative impact on fuel efficiency: at higher per capita income, people may choose the luxury and comfort of large, fuel-inefficient cars. However, available studies--Sweeney (1978) and Griffin (1979), for example--point out that per capita income has had little effect on fuel efficiency choices. The utilization rate is affected by the price of gasoline and per capita income, through their impact on the demand for travel. In addition, the utilization rate will tend to decline as the number of cars per capita increases. For example, a two-car family would not drive twice the mileage of a one-car family given the same demand for travel. Rising per capita income will increase gasoline consumption on the one hand by increasing the number of cars but, on the other hand, it will decrease gasoline consumption by reducing the utilization rate. This was shown clearly in Table 3.1, where the number of cars was shown to increase much faster than gasoline consumption in almost all regions.

These considerations are put together in the following gasoline demand per car equation:

$$\ln\left(\frac{GAS}{CAR}\right) = \beta_0 + \beta_1 \ln\left(\frac{GDP}{POP}\right) + \beta_2 \ln\left(\frac{CAR}{POP}\right) + \beta_3 \sum_{i=1}^{k} \omega_i \ln(PGAS_{t-i+1}), \qquad (3.7)$$

where GAS is the demand for gasoline and all other variables are the same as before. Parameter values of this equation are shown in Table 3.3.

The per capita income (β_1) and per capita car (β_2) parameters are estimated from a pooled sample of seven regions under the assumption that the price coefficients shown are the correct ones. This assumption is necessitated by the lack of sufficiently long time-series data to elicit the adjustments to the price of gasoline. The price elasticities were chosen largely on the basis of the ability to predict recent trends in gasoline

Table 3.3: GASOLINE DEMAND PARAMETERS

Regions	β_1	β_2	β_3	Gasoline Demand Elasticities /b: Income Elasticity 1978	Income Elasticity 2000	Price Elasticity Short Run	Price Elasticity Long Run
NOAM	0.38	-0.30	-0.40	0.87	0.72	-0.13	-0.47
	(1.2)	(-0.9) /a					
WEUR	0.52	-0.55	-0.40	0.88	o.78	-0.12	-0.44
	(1.7)	(-2.5)					
JANZ	0.62	-0.84	-0.40	0.78	0.78	-0.11	-0.41
	(2.0)	(-5.6)					
CSEX	0.60	-0.52	-0.40	1.45	1.39	-0.12	-0.44
	(2.1)	(-4.5)					
CDOP	0.52	-0.46	-0.40	1.32	1.21	-0.13	-0.45
	(1.9)	(-2.8)					
NOEX	0.41	-0.39	-0.40	1.31	1.16	-0.13	-0.46
	(1.8)	(-3.7)					
OIDC	0.52	-0.57	-0.40	1.17	1.07	-0.12	-0.44
	(2.3)	(-4.8)					

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8
-0.27	-0.09	-0.13	-0.17	-0.06	-0.05	-0.04	-0.04
ω_9	ω_{10}	ω_{11}	ω_{12}	ω_{13}	ω_{14}	ω_{15}	ω_{16}
-0.04	-0.03	-0.03	-0.01	-0.01	-0.01	-0.01	-0.01

/a The figures in the parentheses are the t-ratios.

/b Equation (3.7) implies that the income elasticity of gasoline demand ($\varepsilon_{GAS.Y}$) is

$$\varepsilon_{GAS \cdot Y} = \frac{\Delta GAS}{GAS} / \frac{\Delta GDP}{GDP} = \beta_1 + (1 + \beta_2)\ \varepsilon_{CAR.Y}$$

$$= \beta_1 + (1 + \beta_2)\ (\alpha_1 + 2\ \alpha_2 \ln (\frac{GDP}{POP})\ ).$$

Likewise, the long-run price elasticity of gasoline demand ($\varepsilon_{GAS.P}$) is

$$\varepsilon_{GAS.P} = \frac{\Delta GAS}{GAS} / \frac{\Delta PGAS}{PGAS} = \beta_3 + (1+\beta_2)\ \alpha_3\ .$$

The short-run counterparts can be obtained by simply substituting $\beta_3\ \omega_1$ and $\alpha_3\ \omega_1$ for β_3 and α_3, respectively.

consumption. The resulting estimates appear to be reasonable. The per capita income coefficients are not large, while those of the per capita car variable are quite substantial. This result is similar to Griffin's (1979) estimates (0.33 for per capita income and -0.59 for the per capita car variable for industrial countries). Interregional differences in the income effect are relatively small, conforming to the a priori expectation that the rate of change in the utilization rate is likely to be more or less independent of the level of per capita income. As expected, however, the utilization rate is strongly negatively correlated to the level of per capita car ownership.

It is of interest to compare the gasoline demand parameters assumed for WEPM with those of other representative studies shown in Table 3.4. From time-series or cross-sectional, time-series data of the United States, Houthakker and Verleger (1973), Chamberlain (1973), Ramsey, Rasche and Allen (1975) and McGillivray (1976) obtained long-run income elasticities between 0.7 and 1.2 and long-run price elasticities between -0.07 and -0.75. The corresponding short-run elasticities were 0.4 to 0.6 for income elasticity and -0.06 to -0.23 for price elasticity. From quarterly data of US states, Houthakker, Verleger and Sheehan (1974) estimated a low long-run price elasticity of -0.24. The geometric structure of demand adjustments used by these authors resulted in relatively large short-run elasticities. Griffin (1979) and Pindyck (1979), making use of the wide variation of gasoline prices among the industrial countries, obtained significantly larger estimates of long-run price elasticity of gasoline demand, ranging from -1.3 to -1.5. Short-run price elasticities were relatively small, only -0.05 to -0.1. Income elasticities were comparable to those of earlier studies. Sweeney's (1978) income elasticity of gasoline demand is similar to others; his short-run and long-run price elasticities are -0.2 and -0.8 respectively--only slightly higher than the US time-series results.

The income elasticity parameters adopted here for the industrial countries are generally in line with the empirical evidence thus far available. The long-term price elasticity assumption is somewhat more conservative than the results of Sweeney: the Griffin and Pindyck estimates appear to have been overestimated as a result of cross-country differences in transportation modes which are not adequately accounted for in their models.

Table 3.4: ELASTICITY ESTIMATES OF THE DEMAND FOR GASOLINE

Author(s)	Data	Income Elasticity	Price Elasticity	
			Short Run	Long Run
Houthakker & Verleger (1973)	Pooled US states	-		-0.75
Houthakker, Verleger & Sheehan (1974)	US Quarterly Time Series	0.98	-0.075	-0.24
Ramsey, Rasche & Allen (1975)	US Time Series	1.15		-0.70
McGillivray (1976)	US Time Series		-0.23	-0.77
Pindyck (1979)	Pooled OECD	0.84	-0.11	-1.31
Sweeney (1978)	US Time Series & Engineering	0.86	-0.22	-0.78
Griffin (1979)	Pooled OECD	0.77-1.75	-0.06	-1.50

Little is known about the elasticities of the demand for gasoline in developing countries. Pindyck's (1979) estimates from data of five developing countries range from 1.2 to 1.7 for the long-run income elasticity and -0.3 to -0.5 for the long-run price elasticity. The parameters shown in Table 3.3 for developing countries, which were elicited from aggregate data of the developing country regions, are broadly in agreement with Pindyck's results.

The dynamic adjustment path to the price of gasoline shown in Table 3.3 is generally in line with Sweeney's (1978) results. Estimates by Griffin (1979) and Pindyck (1979) indicate only a small initial impact from a gasoline price increase on the demand for gasoline. Sweeney, on the other hand, obtained a substantial first year price elasticity (-0.22), which is likely to be closer to reality than those of Griffin and Pindyck because of the relatively large impact of a gasoline price rise on mileage driven. Average fuel efficiency of automobile stock responds only slowly: efficiency improve-

ment is assumed to peak in about 4 to 5 years and gradually taper off (Table 3.3).

Demand for Diesel Oil for Road Transportation

The demand for diesel oil has been increasing more rapidly than other transportation fuels in recent years (Table 3.5). Diesel engines cost more than gasoline engines, but have better fuel efficiency. With rising fuel prices, diesel powered passenger cars have become more economical and their number has increased rapidly. At the same time, there has been a persistent shift in freight transportation from rail to truck. Furthermore, in many countries the price of diesel oil has been controlled at relatively low levels compared to that of gasoline.

The following simple demand function is postulated for diesel oil:

$$\ln (DSL) = \beta_o + \beta_1 \ln (GDP) + \beta_2 \sum_{j=1}^{k} \omega_j \ln (PDSL_{t-j+1}), \qquad (3.8)$$

where DSL and PDSL are the demand for diesel oil and the real price of diesel oil, respectively. Since diesel oil is consumed mostly by freight trucks, aggregate GDP is likely to be a more relevant determinant of the demand than per capita income. To capture the substitution between diesel oil and gasoline, the relative price of diesel oil to the price of gasoline may be added to the above equation. However, Griffin (1979) found that this variable does not significantly improve the results because the two fuel prices move closely together over time and fuel costs are only a small proportion of the total cost of freight transportation by trucks.

The income and price elasticities shown in Table 3.5 are determined on the basis of their ability to simulate the observed regional time trend. Since the data do not yield reasonable estimates of the price elasticity, it

Table 3.5: WORLD CONSUMPTION OF DIESEL OIL AND ITS DEMAND ELASTICITIES

	Consumption		Ratio of	Demand Parameters	
	1978 Level (MBDOE)	Growth Rate 1970-78	Consumption/GDP Growth Rates	β_1	β_2
NOAM	1.08	11.6	3.3	2.0	-0.3
WEUR	0.81	4.0	1.4	1.3	-0.3
JANZ	0.17	1.6	0.3	1.0	-0.3
CSEX	0.02	16.2	2.3	1.5	-0.3
CDOP	0.04	18.9	2.8	1.3	-0.3
NOEX	0.14	7.2	1.4	1.3	-0.3
OIDC	0.55	10.9	2.0	1.3	-0.3

Memo Item: Lag Structure

$\omega_1 = 0.4, \quad \omega_2 = 0.3, \quad \omega_3 = 0.2, \quad \omega_4 = 0.1$

is assumed to be rather small and the same for all regions, with its dynamic path relatively short and following a declining pattern. 1/

1/ Existing studies--there are only a few such as those of Pindyck (1979) and Griffin (1979)--rely on a simple demand relationship not fundamentally different from the equation (3.8). Using pooled data for industrial countries, Griffin found that the income coefficient is not significantly different from unity, while the price coefficient and its dynamic path came out with a wrong sign. Pindyck also found the long-run income elasticity to be close to unity, but the long-run price elasticity to be quite high, in the range of -0.6 to -1.0 depending on the country. For a small group of developing countries, Pindyck obtained a long-run income elasticity in the neighborhood of 1.5, but the price elasticity had a wrong sign. It is intuitively appealing to assume that the long-run income elasticity is close to unity for the industrial countries. However, this would leave unexplained wide interregional differences in the growth rate of diesel oil consumption. Of particular importance in this regard is the rapid increases in diesel oil consumption for truck transportation in North America. These differences deserve more careful analysis.

Demand for Aviation Fuels

The following relationship is postulated for the demand for aviation fuels (jet kerosine and aviation gasoline):

$$\ln (JAK) = \beta_0 + \beta_1 \ln (GDP) + \beta_2 \ln (POP) + \beta_3 \sum_{j=1}^{k} \omega_j \ln (PJAK_{t-j+1}), \quad (3.9)$$

where JAK and PJAK are the demand for aviation fuels and its real price, respectively. The equation posits that the demand for air travel is determined in part by the size of the population. The population variable is entered as a separate explanatory variable to make the equation more general than the case where per capita consumption is explained by per capita income. The price of aviation fuels is used as a proxy for the total user cost of air travel.

The income and population coefficients are chosen at levels that would closely replicate the recent trend (Table 3.6). The income elasticities chosen for the industrial countries are relatively low compared with available estimates. 1/ For the developing countries, the income elasticity is assumed to be slightly higher than those for the industrial countries.

The long-run price elasticity chosen for all the regions is close to the lower end of available estimates. Because the fuel cost is only a small part of the total cost of air travel, the price elasticity is expected to be rather small. In fact, airline fares have been declining in real terms as a

---

1/ Only a few studies are available on aviation fuel consumption. Using functional forms similar to (3.9) above, Griffin (1979) and Pindyck (1979) obtained, from pooled data of industrial countries for the 1960s and early 1970s, high income elasticities (1.2 to 3.8), and exceedingly high price elasticities (-0.3 to -1.8). High income elasticities are justified on the ground that air travel is the preferred mode of long distance passenger travel. The authors correctly suspect that the price elasticity estimates could well be spurious ones. It should be remembered, however, that aviation fuel consumption increased rapidly in the 1960s (at 7.6% p.a.), but the growth rate slowed down substantially in the 1970s to only 3.3% p.a. during 1970-78 (Table 3.6). Not all of this slowdown can be accounted for by increases in fuel prices and deceleration of income growth. One possible explanation is the saturation phenomenon. Another factor could be the introduction of the fuel efficient jumbo jets.

Table 3.6: WORLD CONSUMPTION OF AVIATION FUELS AND ITS DEMAND ELASTICITIES

	Consumption 1978 Level (MBDOE)	Consumption Growth Rate 1970-78	Ratio of Consumption/ GDP Growth Rate	Demand Parameters β_1	β_2	β_3
NOAM	1.15	1.3	0.37	1.3	-0.60	-0.40
WEUR	0.33	3.5	1.21	1.5	-0.50	-0.40
JANZ	0.11	10.4	2.08	1.6	-0.50	-0.40
CSEX	0.07	27.5	3.87	2.0	-0.40	-0.40
CDOP	0.04	9.1	1.38	1.7	-0.40	-0.40
NOEX	0.04	9.1	1.78	1.6	-0.40	-0.40
OIDC	0.29	7.7	1.40	1.6	-0.40	-0.40

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8	ω_9
0.19	0.10	0.06	0.04	0.04	0.06	0.06	0.08	0.08
ω_{10}	ω_{11}	ω_{12}	ω_{13}	ω_{14}	ω_{15}	ω_{16}	ω_{17}	ω_{18}
0.06	0.06	0.04	0.04	0.04	0.02	0.02	0.02	0.01

result, in part, of industry deregulation in the United States, despite the steep increases in fuel costs. The industry, nevertheless, is in the process of substantially improving the fuel efficiency of air travel by substituting fuel efficient aircraft for the existing fleet. This process is likely to take a long time as postulated in the dynamic path shown in Table 3.6.

Fuel Demands for Other Transportation

Rail, and internal and coastal navigation fuels are treated jointly here since the total fuel consumption by these sectors is relatively small. The following demand function is postulated for the other transportation fuels:

$$\ln (ROT) = \beta_0 + \beta_1 \ln (GDP) + \beta_2 \sum_{j=1}^{k} \omega_j \ln (PROT_{t-j+1}), \qquad (3.10)$$

where ROT is the total fuel demand by all other transportation sectors and PROT is the weighted average real price of fuels used by them. It is assumed

that the fuel shares of ROT will remain constant; the demand for petroleum products, coal, and electricity is obtained by applying the 1976-78 fuel shares to ROT.

Table 3.7 shows the relevant statistics for this sector. Total fuel consumption has been stagnant or declining throughout the 1960s and the 1970s.

Table 3.7: WORLD FUEL DEMAND FOR OTHER TRANSPORTATION

	Consumption		1976-78 Fuel Shares (%)			Demand Parameters	
	1978 Level (MBDOE)	Growth Rate (%) 1970-78	Petroleum	Coal	Electricity	β_1	β_2
NOAM	0.38	2.17	98	0	2	0.5	-0.28
WEUR	0.23	-2.43	73	5	22	0.4	-0.28
JANZ	0.28	6.44	87	1	12	0.5	-0.28
CSEX	0.0	0.0	0	0	0	0.5	-0.28
CDOP	0.0	0.0	0	0	0	0.5	-0.28
NOEX	0.02	3.64	97	1	2	0.5	-0.28
OIDC	0.49	1.20	84	7	9	0.7	-0.28

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8	ω_9	ω_{10}
0.18	0.04	0.07	0.07	0.11	0.14	0.18	0.11	0.07	0.04

The only exception is Japan where there was a sudden one-year jump in navigational fuel consumption, which appears to be a statistical error. The demand parameters assumed in Table 3.7 allow for a moderate growth in demand, largely prompted by the expectation that these transport sectors may see some revival of interest because they provide relatively more fuel efficient modes of freight transport and urban mass transportation than road or air transportation.

3.3 Industrial Demand for Energy

The industrial sector is the largest consumer of energy, accounting for about 41% of world final energy consumption: the developing countries

typically consume 50~70% of final energy in the industrial sector, while in the industrial countries the share is 30~50%. The sector uses energy as inputs into production processes. Substitutability between energy and other factors of production and between various forms of energy is the key determinant of future growth in industrial demand for energy. Table 3.8 provides an overview of industrial energy consumption, excluding the iron and steel industry. Because of its relatively large size and direct connection with the iron and steel industry, the demand for metallurgical coal by the iron and steel industry is treated separately.

Factor Substitution and Industrial Demand for Energy

The industrial demand for energy (ENI) is specified as a log-linear function of industrial value-added (GDPI) and a measure of the real price of energy (PENI):

$$\ln (ENI) = \beta_0 + \beta_1 \ln (GDPI) + \beta_2 \sum_{j=1}^{k} \omega_j \ln (PENI_{t-j+1}), \qquad (3.11)$$

where β_1 is recognized as the output elasticity, and β_2 as the long-run elasticity of substitution between energy and value-added. Table 3.9 shows the base-case parameter values.

Table 3.8: THE STRUCTURE OF INDUSTRIAL ENERGY DEMAND /a

	1978 Consumption (MBDOE)	Growth Rate 1960-1978 (%)	1978 Fuel Shares (%)			
			Petroleum	Natural Gas	Coal	Electricity
NOAM	9.40	3.1	41	33	9	17
WEUR	6.05	4.2	54	22	6	17
JANZ	3.04	7.9	70	4	5	21
CSEX	0.93	11.7 /b	67	31	1	1
CDOP	0.64	14.1 /b	61	36	0	3
NOEX	0.97	9.2 /b	54	36	3	7
OIDC	4.00	6.3 /b	63	6	15	16
TOTAL	25.03	3.7 /b	53	23	8	16

/a Excluding the iron and steel industry.
/b Growth rate between 1967 and 1978.

The output elasticities in Table 3.9 posit no significant structural changes in industrial growth of the industrial countries, but a continuation of recent trends in industrial growth for the developing countries. Available estimates for the industrial countries, e.g., Griffin (1979), appear to support the view that the output elasticity is not significantly different from unity. Pindyck's (1979) estimates, however, are not conclusive on this point; his estimates of the output elasticity range between 0.62 and 0.86. Pindyck does not adjust for the fact that inefficient coal was replaced by efficient petroleum and natural gas in the 1960s and the early 1970s, thus underestimating energy consumption growth in terms of useful energy. Adams and Miovic (1968) showed that an adjustment for efficiency of different fuels raised the estimate of output elasticity by 0.2 compared with an unadjusted estimation. Pindyck's results, therefore, are not necessarily contradictory with the unitary elasticity estimate.

Studies of output elasticities for the industrial sector of developing countries are virtually nonexistent, largely because of the lack of required data. Choe (1978 and 1980) showed estimates of income elasticities

Table 3.9: PARAMETERS OF AGGREGATE INDUSTRIAL ENERGY DEMAND

	Income Elasticity β_1	Elasticity of Substitution β_2
NOAM	1.00	-0.75
WEUR	0.90	-0.85
JANZ	0.95	-0.75
CSEX	1.20	-0.35
CDOP	1.15	-0.35
NOEX	1.15	-0.35
OIDC	1.10	-0.40

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8	ω_9
0.15	0.10	0.07	0.04	0.05	0.06	0.07	0.07	0.06
ω_{10}	ω_{11}	ω_{12}	ω_{13}	ω_{14}	ω_{15}	ω_{16}	ω_{17}	ω_{18}
0.06	0.05	0.05	0.04	0.04	0.03	0.03	0.02	0.01

of total energy consumption that ranged between 1.2 and 1.6 for broad groups of developing countries. Hoffmann and Mors (1981) showed that the increasing share of industrial output in GDP explains a significant part of the high income elasticity in developing countries. The industrial output elasticities for the developing country groups are set at levels slightly blow the available estimates of aggregate output elasticities, in order to eliminate the impact of increasing share of industrial output.

The price elasticity of industrial energy demand has been an area of much contention. Table 3.10 summarizes the representative estimates of the long-term price elasticity of industrial energy demand. Using the translog

Table 3.10: ESTIMATES OF PRICE ELASTICITY OF INDUSTRIAL ENERGY DEMAND

Author(s)	Data	Long-Term Price Elasticity	Associated Income Elasticity
Berndt & Wood (1975)	US Time Series	-0.49	
Nordhaus (1979)	6 Industrial Countries Pooled	-0.48 ~ 0.52	0.76 ~ 0.91
Fuss & Waverman (1977)	Canadian Time Series	-0.36 ~ -0.59	
Magnus	Dutch Time Series	-0.29	
Halvorsen & Ford (1978)	US Industry Subsectors	-0.66 ~ -2.56	
Pindyck (1979)	Pooled OECD	-0.75 ~ -0.84	0.62 ~ 0.86
Griffin (1979)	Pooled OECD	-0.80 (Translog Model) -0.40 (Simple Model) Short-run price elasticity in translog model = -0.13	1.00

factor demand model involving energy, capital, labor and material inputs, Berndt and Wood (1975) found from US manufacturing time-series data an own price elacticity estimate of -0.49 for energy, together with capital-energy complementarity. Similar results were obtained by Fuss (1977) from Canadian manufacturing time-series data, with estimates ranging between -0.36 and -0.59. Magnus obtained the same type of results with the Dutch manufacturing data.

The same methodology applied to the OECD cross sectional time-series data--Griffin (1979), Griffin and Gregory (1976), and Pindyck (1979)--produced quite different results in that capital and energy are found to be substitutes and the long-term own price elasticity is about -0.8. A study of US manufacturing by Halvorsen and Ford (1978) at the two-digit level found generally high values for the price elasticity.

The simplified energy value-added relationship in equation (3.11) estimated by Griffin (1979), produced a disturbingly low estimate (-0.4) for the elasticity of substitution between energy and value-added despite the international cross-section orientation. Estimates obtained by Nordhaus using a similar equation are somewhat higher (-0.48 ~ -0.52). As pointed out by Berndt and Wood (1979), the restrictive assumptions in the simplified approach--weak separability between energy and capital/labor and the disregard of material input in the production function--may be responsible for the low estimates of the price elasticity.

The long-term price elasticities chosen for the industrial countries are generally in line with those of Griffin and Pindyck estimated from the translog cost share model. The basic reason for this choice is the standard one that international cross-sectional, time-series data are more likely to reflect long-term adjustments to energy prices. Energy-capital complementarity and concommitant low estimates of the price elasticity of energy demand are contrary to engineering evidence that substantial energy saving is indeed possible through substitution of capital for energy. Furthermore, a low price elasticity of industrial energy demand is not consistent with recent trends in industrial energy consumption.

Estimates of the price elasticity of industrial energy demand for developing countries are extremely rare. Choe (1978 and 1980) obtained an

average of -0.3 for the price elasticity of total primary energy demand for 40 developing countries. This estimate was obtained from time-series data and, hence, may be considered an underestimate. Nevertheless, the price elasticities for developing countries are chosen at levels substantially lower than those for industrial countries as a way of taking into consideration the likelihood that the availability of capital will be an important constraint on substitution of capital for energy.

Evidence thus far on the dynamic adjustment path of industrial energy demand to energy price changes is extremely weak. Griffin (1979) attempted to estimate a second degree polynomial lag model from the OECD industrial energy cousumption data, but obtained unreasonably high short-run elasticities and the medium- to long-term elasticities had the wrong sign. The average life of industrial capital stock is about 10 to 15 years, but a full adjustment to changes in relative factor prices may take longer than that because of investment lags. The chosen values for the short- to medium-run elasticities (Table 3.9) are broadly consistent with demand adjustments that took place in industrial countries after the 1973/74 price increases. It is postulated that the bulk of energy savings (73% of the total) will be achieved within 10 years after a price increase.

Interfuel Substitution in Industrial Energy Consumption

Within the technologically feasible limits, industrial fuel choices depend on relative fuel prices, associated capital costs, and the costs of environmental control. It is generally the case that various types of fuels are highly substitutable for one another within a wide band, particularly in their thermal uses. Thus, the industrial countries drastically reduced the share of coal in the 1960s and early 1970s. A number of countries also do not consume any natural gas, with petroleum products satisfying most of the needs of the potential markets for natural gas. The wide variation in fuel shares across countries and over time is an indication of a high degree of substitutability between fuels.

Evidence on interfuel substitution elasticities generally confirms the *a priori* expectation of a high degree of substitutability in the long run. Table 3.11 shows the long-run, own- and cross-price elasticities assumed for our model. These are compared with the representative econometric

Table 3.11: LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THE INDUSTRIAL SECTOR--WEPM AND OTHER STUDIES

	WEPM /a	Griffin /a (1979)	Pindyck /a /b (1979)	Halvorsen (1975)	Fuss, Hyndman & Waverman (1975)
ε_{CC}	-1.20	-1.17	-1.71	-1.46	-2.51
ε_{GG}	-1.40	-1.14	-1.08	-1.32	-2.53
ε_{EE}	-0.40	-0.46	-0.13	-0.66	-0.60
ε_{OO}	-0.70	-0.71	-0.44	-2.75	-1.32
ε_{CG}	0.15	0.09	1.08		
ε_{CE}	0.69	0.82	0.19		
ε_{CO}	0.35	0.27	0.44		
ε_{GE}	0.61	0.52	0.02		
ε_{GO}	0.64	0.53	0.02		
ε_{EO}	0.05	0.11	0.08		

Memo Item: Lag Structure

$\omega_1 = 0.045$	$\omega_2 = 0.082$	$\omega_3 = 0.109$	$\omega_4 = 0.127$
$\omega_5 = 0.136$	$\omega_6 = 0.136$	$\omega_7 = 0.127$	$\omega_8 = 0.109$
$\omega_9 = 0.082$	$\omega_{10} = 0.045$		

/a Evaluated at the following cost shares:

$$S_C = 0.131,\ S_G = 0.136,\ S_E = 0.503,\ S_O = 0.230$$

/b Using the version of ten countries, 1959-73, with country dummies.

estimates using the translog cost share approach. For ease of comparison, the elasticities are evaluated, to the extent possible, at the OECD average fuel cost shares appearing in Griffin (1979). It was decided that there is not sufficient grounds at this point for distinguishing between industrial and developing countries in terms of their magnitude and the time path of adjustment for interfuel substitution parameters (β_{ij}'s in equation (3.3)); however, the own- and cross-price elasticities (ε_{ij}'s in equation (3.4)) will

be different between the regions. 1/ Following Griffin's estimates, we chose -0.7 for the own-price elasticity of petroleum. Own-price elasticities for coal and natural gas are assumed at levels closely in line with the available estimates. The relatively high own-price elasticities assumed are justified because of their close substitutability in thermal energy markets and their current low cost shares. The own price elasticity of electricity is assumed to be rather small (-0.4), because of its high cost share and because its uses are more specific than other fuels. 2/ It is assumed that natural gas is more substitutable than coal, when the cost shares are the same. Natural gas, petroleum and electricity are assumed to be close substitutes.

It is of interest to examine the direction of interfuel substitution implied by the WEPM parameters. A 10% increase in the price of petroleum, for example, results in a 7% decrease in the demand for petroleum which is compensated by a 3.5% increase in coal, a 6.4% increase in natural gas and a

---

1/ The only empirical study for a developing country is that of Uri (1979) for India. His estimates of own- and cross-price elasticities of fuel substitution are substantially lower than those for OECD countries. The lack of sufficient variation in relative fuel prices seems to be responsible for the apparent underestimation.

2/ Griffin's estimates from his preferred model show own-price elasticity in excess of -1.0 for coal and natural gas, -0.7 for petroleum, and -0.46 for electricity. The low own-price elasticity of electricity demand is confirmed by other studies: Halvorsen's (1975) estimate for the United States (-0.66) is close to Griffin's, while Pindyck's (1979) are substantially lower (-0.13). Fuss, Hyndman and Waverman (1975) obtained -0.6 for Canada's own price elasticity for electricity. We assume -0.4, which is essentially the same as Griffin's and does a reasonable job in simulating recent industrial electricity consumption trends. Griffin's own-price elasticity for petroleum is on the low side compared with other estimates. Halvorsen, for example, obtained an estimate of -2.7 for the United States, while the estimate by Fuss, Hyndman and Waverman for Canada is -1.32. Pindyck's results may provide an explanation for this divergence: his own-price elasticity estimates for petroleum for the United States and Canada are on the high side (-0.81 to -1.1), but those for Western Europe and Japan are extremely low (-0.11 to -0.34). His estimate for the industrial countries as a whole is only -0.44, estimated from between-year variations by introducing country dummy variables in the estimation.

0.5% increase in electricity; those changes will maintain the same level of total energy inputs into industry. At the 1978 fuel shares in North America, for example, the substitutes for petroleum will consist of 13% coal, 83% natural gas and 4% electricity, in the absence of supply constraints. This seems plausible in view of the close substitutability between petroleum and natural gas, while coal will be the second in line to take up the thermal portion; the specificity of electricity uses explains its minor role as a substitute fuel.

Section 3.1 stated the difficulties of accommodating the appropriate dynamic path for interfuel substitution within the static translog cost share framework. This problem cannot be corrected by any reasonable variations in the lag structure as the one shown in Table 3.11. The short-run interfuel substitution results, therefore, should be regarded with caution in terms of their likely overestimation; the long-run results are not subject to the same problem.

Demand for Metallurgical Coal by the Iron and Steel Industry

Demand for metallurgical coal by the iron and steel industry accounted for 62% of total final consumption of coal by the industrial sector of the industrial countries in 1978. In the oil-importing developing countries, the share was 34%. The demand model for metallurgical coal is based on the recognition that the location of future iron and steel capacity expansion will be the dominant factor in determining the demand for metallurgical coal. For this purpose, we can make use of the iron and steel capacity projections done independently in the Bank. Fuels other than metallurgical coal used by the iron and steel industry are assumed to follow the substitution responses of the industrial sector.

Demand for metallurgical coal (MCOAL) is related to pig iron production (IRN) by:

$$MCOAL_t = A_0 \; e^{-\lambda t} \; IRN_t, \qquad (3.12)$$

where A_0 is the metallurgical coal requirements per ton of pig iron production in the base year and λ is the rate of fuel-saving technical progress. Production of pig iron is taken as the proxy for the iron and steel complex, because metallurgical coal is used mostly for pig iron production.

Metallurgical coal requirements per ton of pig iron production have been declining steadily in the past 20 years. Table 3.12 shows the results of estimating λ from the 1960-78 data. The industrial countries have achieved significant improvements in energy efficiency of pig iron production during the period. Further improvements are likely to be increasingly more difficult to achieve. Furthermore, the industrial countries are not expected to add substantial new iron and steel capacities that would enhance the overall energy efficiency of the industry. Metallurgical coal consumption per unit of pig iron production in the oil-importing developing countries is estimated to be at least 50% higher than that of industrial countries. This leaves a lot of room for efficiency improvements in these countries. The bulk of new investments in iron and steel is expected to take place in developing countries, substantially improving the overall energy efficiency of the industry in the years ahead.

Table 3.12: ENERGY SAVING TECHNICAL PROGRESS IN THE IRON AND STEEL INDUSTRY

	Estimate of λ	t-ratio	$\bar{R}^2$	Assumed Value of λ in WEPM
NOAM	0.015	2.02	0.11	0.005
WEUR	0.033	31.55	0.98	0.005
JANZ	0.034	6.09	0.99	0.005
OIDC	-0.038	-1.29	0.95	0.030

3.4 Residential Demand for Energy

This section deals with final energy consumption in the residential/commercial sectors, agriculture, and public services. Although these sectors have different consumption characteristics, they are treated

here as a homogeneous group, referred to jointly as the residential sector for the sake of simplicity. 1/

Table 3.13 summarizes the structure and trend of residential energy consumption. The residential sector typically accounts for about 30% of total final energy consumption in the industrial countries, and only 17% in the developing countries. The lower share in the developing countries is explained largely by the following: (a) many developing countries are located in tropical or subtropical zones where space heating is not required, while space cooling has not reached a significant proportion; 2/ (b) developing

Table 3.13: THE STRUCTURE OF RESIDENTIAL ENERGY CONSUMPTION

	1978 Consumption (MBDOE)	Annual Growth Rate 1960-78 (%)	1978 Fuel Shares (%)			
			Petroleum	Coal	Natural Gas	Electricity
NOAM	9.71	2.93	32.6	1.1	41.6	24.7
WEUR	6.32	4.21	51.8	8.5	22.5	17.1
JANZ	1.40	8.93	58.0	5.9	10.9	25.2
CSEX	0.25	16.02 /a	87.6	0.0	4.0	12.0
CDOP	0.25	9.71 /a	64.0	0.0	24.0	12.0
NOEX	0.23	9.10 /a	68.7	0.0	7.0	24.3
OIDC	2.03	9.53 /a	51.7	23.2	4.4	20.7
TOTAL	20.19		43.8	5.9	28.7	21.6

/a Growth rates between 1967 and 1978.

1/ In the industrial countries, the residential sector accounts for 75% of the final energy consumption of this group, the commercial sector for 20%, and agriculture and public services for 5%. In the developing countries, the share of the agricultural sector would be higher, but available statistics do not give a clear distinction between the residential and agricultural sectors.

2/ A study of nine industrial countries by Darmstadter, et al. (1977) revealed that space conditioning typically accounts for 65-85% of final energy consumption of the household sector.

countries rely heavily on traditional fuels such as fuel wood and agricultural biomass, which are not included in the data. Residential energy consumption has been increasing rapidly in the developing countries (particularly in the middle-income developing countries).

Total Residential Demand for Energy

Per capita residential energy consumption is explained by a log-linear function of per capita income and the real price of residential energy of the following form:

$$\ln\left(\frac{ENR}{POP}\right) = \beta_0 + \beta_1 \ln\left(\frac{GDP}{POP}\right) + \beta_2 \sum_{j=1}^{k} \omega_j \ln\left(PENR_{t-j+1}\right), \qquad (3.13)$$

where the notation is the same as before except that ENR and PENR are residential energy demand and real residential energy price, respectively. The demand function (3.13) is a statement of the basic consumer demand theory that income and prices are the main determinants of consumer demand. 1/

Because of the large share of energy used for space conditioning, the temperature variable (measured by heating degree days) featured prominently as an explanatory variable for residential energy demand. However, statistical results of intercountry analyses including the temperature variable have been disappointing for reasons not immediately clear. It is equally unclear in which direction the estimates of other parameters might have been biased because of the poor performance of the temperature variable. For the purpose of projections, the temperature variable can be ignored as long as the income and price coefficients are not affected by this omission.

Table 3.14 presents the parameters of the residential energy demand model assumed for the base case. They can be compared with the results from existing studies which are summarized in Table 3.15. Somewhat divergent results have been obtained for the income elasticity from time-series data of industrial countries. From US time series, Joskow and Baughman (1976)

1/ The model implicitly assumes that energy is weakly separable from other consumer goods in the utility function so that the elasticities of substitution between energy and other consumer goods are identical for all consumer good categories.

Table 3.14: INCOME AND PRICE ELASTICITIES OF RESIDENTIAL ENERGY DEMAND

	Income Elasticity (β_1)	Price Elasticity Short-Run ($\beta_2 \cdot \omega_1$)	Price Elasticity Long-Run (β_2)
NOAM	0.85	-0.16	-0.80
WEUR	1.00	-0.14	-0.70
JANZ	1.10	-0.16	-0.80
CSEX	1.35	-0.10	-0.50
CDOP	1.25	-0.10	-0.50
NOEX	1.20	-0.10	-0.50
OIDC	1.20	-0.12	-0.60

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8	ω_9
0.20	0.12	0.08	0.07	0.06	0.06	0.05	0.05	0.04
ω_{10}	ω_{11}	ω_{12}	ω_{13}	ω_{14}	ω_{15}	ω_{16}	ω_{17}	ω_{18}
0.04	0.04	0.04	0.03	0.03	0.03	0.02	0.02	0.02

obtained estimates ranging from 0.4 and 0.6. Results of other studies using the same data are not much different. These are in sharp contrast with the time-series estimates by Rodseth and Strom (1976) for Norway and by Fuss, Hyndman and Waverman (1975) for Canada, which all came close to unity. International cross-sectional, time-series results by Nordhaus (1979), Griffin (1979), and Pindyck (1979), show remarkable unanimity in that they are not significantly different from unity.

The prevailing view of the above studies seems to be that the income elasticity for the industrial countries as a whole should be close to unity, although some differences between industrial countries are to be expected. The income elasticity parameters chosen for the industrial country groups are broadly in agreement with existing studies except that they differ somewhat to reflect the differences in residential energy consumption trends. The income elasticities assumed for the developing countries are significantly higher

Table 3.15: ESTIMATES OF RESIDENTIAL ENERGY DEMAND ELASTICITIES

Authors	Data	Income Elasticity (β_1)	Long-Run Price Elasticity (β_2)
Joskow & Baughman (1976)	US Time Series	0.60	-0.50
Nordhaus (1979)	OECD Pooled Data	1.09 - 1.39	-0.71
Fuss, Hyndman & Waverman (1975)	Canada Time Series	0.83 - 1.26	-0.33 ~ -0.56
Rodseth & Strom (1976)	Norway Time Series	1.08	-0.30
Pindyck (1979)	OECD Pooled Data	1.00	-1.05 ~ -1.15
Griffin (1979)	OECD Pooled Data	1.028	-0.951

than those for the industrial countries to account for strong consumer preference for energy-consuming durable goods in the middle-income developing countries and the shift from traditional to commercial fuels. 1/ Per capita consumption of residential energy has increased at 1.5 times the growth rate of per capita income in the oil-importing developing countries but a signifi-

1/ A declining agricultural share of GDP and rural-to-urban migration in developing countries will result in an increasing share of commercial sources of energy at the expense of traditional fuels. Given the strong negative correlation between the agricultural share of GDP and the level of per capita GDP, the above process implies that the GDP elasticity of residential commercial energy will be higher than that of total residential energy demand including the traditional fuels. The role of traditional fuels, thus, can be taken into consideration indirectly by adjusting upward the income elasticity of commercial fuels.

cant part of this can be attributed to the declining real price of energy during 1967-73. For the petroleum-exporting countries, GDP understates the increases in disposable income for the recent period of rapid petroleum price increases. Estimates of income elasticity based on data that include this period should be considered as overestimates.

The long-run price elasticity of residential energy demand also has been an area of conflicting econometric evidence. As in the case of the industrial sector studies, the differences pertain to time-series vs. cross-sectional, time-series estimation. Studies of time-series data typically produced estimates of the long-run price elasticity ranging between -0.3 and -0.6. Estimates from international cross-sectional, time-series data are about twice as large as the time-series results. 1/

We argue that the long-run price elasticity of residential energy demand for the industrial countries is likely to be somewhat less than unity. The cross-country differences in per capita residential energy consumption include some fundamental differences reflecting lifestyle and cultural background that are not influenced by energy prices. The energy price variable could have picked up some of these differences in the international cross sectional estimation. 2/ Because of this, a long-run price

---

1/ Griffin and Pindyck obtained similar estimates, ranging between -0.95 and -1.15. This implies that the expenditure share on energy by households will remain approximately constant in the long run regardless of changes in the residential energy price. With the income elasticity close to unity, a further implication is that the household expenditure share on energy will be approximately the same across countries and over time in the industrial countries, except for such factors as weather and certain lifestyle differences. Indeed, Darmstadter, et al. (1977) found relatively small variations between the major industrial countries in the share of consumption expenditures on energy other than transportation fuels. Japan was an exception. Japanese households spend a substantially smaller proportion of their consumption expenditure on energy than other industrial countries.

2/ A case in point is the predominance of single family detached houses in North America. This is more energy intensive than, for example, apartment dwelling prevalent in other industrial countries. The fact that energy is cheaper in North America than in other industrial countries is largely coincidental to this difference.

elasticity of around -0.8 is used for the industrial countries. Somewhat lower long-run price elasticities are assumed for the developing countries on the grounds that their household energy consumption is still mostly for meeting basic needs and the scope for saving is likely to be limited.

Empirical evidence on the dynamics of residential energy demand adjustments is extremely weak. The life span of residential and commercial structures stretches over a long period. It is clear, however, that much of the potential energy savings in the residential sector can be achieved by retrofitting existing structures for better insulation, replacement of household appliances and equipment with more energy efficient units, and installation of energy-saving devices such as heat pumps. These measures can be implemented in a relatively short time and without necessarily having to replace the existing structures. For this reason, we assume relatively high short-run elasticities; the bulk of adjustment (77% of the total) is assumed take place in the first 10 years. 1/

Interfuel Substitution in the Residential Sector

The fact that the residential sector consists of decentralized small-scale users makes distribution costs, convenience and cleanliness premiums important considerations in fuel substitution decisions. In this regard coal is considered an inferior fuel. Even if the price of coal--determined largely by the large-scale thermal energy market--goes down, the residential demand for coal is not likely to increase significantly unless the price advantage more than compensates for the inconvenience and dirtiness of coal burning in residential consumption. The model deals with this problem by adding to the residential price of coal an inconvenience and dirtiness penalty that increases in proportion to per capita income.

1/ Griffin's (1979) best estimate, obtained with a linear lag structure, suggests that the initial impact of an energy price increase is large, and that adjustment takes about seven years. Other estimates of the short-run (one year) price elasticity vary from -0.12 to -0.63, with Griffin's estimate coming at the middle of the range. The relatively large short-run elasticity estimates attest to the significant degree of adjustment that can take place in the short run.

Table 3.16 presents the interfuel substitution elasticities assumed for the base case of our model and compares them with the results of other studies. The dynamic structure and the interfuel substitution parameters (β_{ij}'s) are assumed to be the same for all the regions. For the own-price elasticity of petroleum, we choose a level close to Pindyck's result, estimated from pooled between-country and between-year variations. The own-price elasticity assumed for coal is close to Pindyck's but substantially lower than Griffin's. The own-price elasticity for natural gas is set on the high side of available estimates on the grounds that it is a preferred fuel in

Table 3.16: LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THE RESIDENTIAL SECTOR--WEPM AND OTHER STUDIES

	WEPM /a	Griffin /a (1979)	Pindyck /a /b (1979)	Joskow & Baughman (1976)	Hirst, Lin & Cope (1976)	Halvorsen (1975)
ε_{CC}	-0.94	-4.09	-0.94 ~ -0.99			
ε_{GG}	-2.00	-2.61	-1.20 ~ -1.99	-1.01	-0.91	
ε_{EE}	-0.60	-0.72	+ ~ -0.54	-1.00	-0.84	-1.0 ~ -1.2
ε_{OO}	-1.10	-0.86	-1.04 ~ -1.29	-1.10	-0.91	
ε_{CG}	0.12	1.04				
ε_{CE}	0.59	1.36				
ε_{CO}	0.23	1.69				
ε_{GE}	1.28	2.03				
ε_{GO}	0.66	0.06				
ε_{EO}	0.28	0.16				

Memo Item: Lag Structure

$\omega_1 = 0.045$	$\omega_2 = 0.082$	$\omega_3 = 0.109$	$\omega_4 = 0.127$	$\omega_5 = 0.136$
$\omega_6 = 0.136$	$\omega_7 = 0.127$	$\omega_8 = 0.109$	$\omega_9 = 0.082$	$\omega_{10} = 0.045$

/a Evaluated at the following cost shares (averages of industrial countries, 1955-72): $S_C = 0.061$, $S_G = 0.12$, $S_E = 0.587$, $S_O = 0.232$.

/b Nonstationary model, 1960-74, nine countries pooled together.

residential uses and its current share is relatively low in many potential markets. The own-price elasticity for electricity is assumed to be at about the average of available estimates. 1/

The substitution elasticities assumed for the model posit that electricity and natural gas, but not coal, will be the primary substitutes for petroleum in residential uses. 2/ At the 1978 fuel shares in North America, for example, the elasticities imply that substitutes for petroleum will consist of 79% natural gas, 20% electricity and less than 1% coal, in the absence of any supply constraints.

3.5 Fuel Substitution in Electricity Generation

Thermal electric power generation is by far the largest energy transformation activity. In 1978, about 22% of the world's primary fossil energy consumption was used for thermal electricity generation to supply 67% of all electricity consumption.

The thermal power industry has received much attention because of its fuel substitution potential. Unlike the final consumption sectors, coal still maintains a large share of the thermal electricity market in the industrial

---

1/ Griffin's (1979) estimate of the own-price elasticity for petroleum is -0.86 for the industrial countries as a whole; but his estimation model for the residential sector includes country dummy variables to eliminate between-country variations. Studies by Joskow and Baughman (1976), Hirst, Lin and Cope (1976) for the United States, and Fuss, Hyndman and Waverman (1975) for Canada indicate own-price elasticities of petroleum close to Griffin's results. In view of the time-series orientation of these estimates, they are suspected of underestimation. Estimates of the own-price elasticity of electricity tend to come out the lowest among the fuels; Pindyck and Griffin obtained -0.54 and -0.72, respectively, for the average of industrial countries. Griffin's estimate of a high own-price elasticity for coal is problematical in view of its inferiority as a residential fuel.

2/ Griffin's and Pindyck's estimates indicate strong substitution elasticities between petroleum and natural gas in countries where natural gas was available to residential users. Griffin's low estimate of ε_{GO} for the industrial countries as a whole is likely to be an underestimate because of the supply constraints. Significant substitution elasticities between petroleum and electricity were observed by Griffin for the industrial countries. As expected, Griffin also finds a high degree of substitution between natural gas and electricity.

countries and the oil-importing developing countries. In terms of thermal combustion characteristics, the three primary fossil fuels--coal, petroleum and natural gas--do not differ substantially except in the areas of pollution and capital costs. Over the long term, therefore, the three fuels should be highly substitutable.

Fuel Efficiency of Thermal Electricity Generation

For simplicity, we assume the following demand function for fossil fuels for thermal electricity generation: 1/

$$FENEL_t = A_0 \quad e^{\lambda t} \quad FEL_t, \tag{3.14}$$

where FENEL is the fossil energy inputs for thermal electricity generation, FEL is the demand for thermally-generated electricity (total demand for electricity minus supplies of primary electricity), λ is the rate of efficiency improvements, and A_0 is the base-year conversion efficiency.

From the historical data (1960-78) of the industrial countries, λ is estimated at about 2.7% per annum. However, the data show practically no significant efficiency improvements in the 1970s, indicating that the technological limits have been reached in these countries. Two new technologies, at different R & D stages, can potentially improve fuel efficiency in the future. One is combined cycle power generation--driving gas turbines by hot gas from fossil fuels to generate electricity and using the hot exhaust gas for conventional steam power generation--which potentially can enhance the efficiency up to 48%. The MHD (Magnetohydrodynamics) process--passing very hot gas through a magnetic field at high speed--can potentially yield a conversion efficiency of up to 60% when combined with the conventional steam cycle. The combined

---

1/ This formulation assumes a constant-return-to-scale production function with Hicks-neutral technical progress and zero elasticity of substitution between fuel and other factors of production (capital and labor) in thermal electricity generation. Empirical estimates by Griffin (1979) support the view that the elasticity of substitution is not significantly different from zero and the returns to scale is approximately constant in industrial countries, where most thermal power plants have already exploited the scale economies.

cycle technology is likely to become commercially viable well ahead of the MHD, probably late in this century.

It is clearly unrealistic to assume a continuation of 2.7% efficiency improvements annually for the entire projection period. Instead, we assume that by the year 2000, efficiency will improve by 10% over the current level, under the assumption that the combined cycle technology will make considerable inroads by that time. This is equivalent to a value for λ of 0.005.

Fuel Substitution in Thermal Electricity Generation

From a purely technological point of view the three major fossil fuels used for thermal electricity generation should be highly substitutable with one another. However, the substitutability has been less than perfect because of environmental constraints, lack of transportation infrastructure, and the need for peak-load generating capacities. Because of environmental problems, power plant conversions to coal have been restricted in areas where pollution has reached certain high levels. For some peak-load and small scale facilities, hydrocarbon fuels are preferred to coal because of relatively low capital costs. 1/

Table 3.17 shows the interfuel substitution elasticities assumed for the thermal power sector and compares them with the evidence of representative studies. The studies indicate that the own-price elasticity of petroleum is somewhat larger than that of coal, when the cost shares of coal and petroleum are about the same. This result makes sense in view of the high non-fuel costs and environmental restrictions associated with coal burning. The own-price elasticities for coal and petroleum chosen for WEPM are broadly in line

---

1/ Generally, natural gas-fired or diesel-powered generating plants require the least amount of capital investment per unit of capacity. Capital costs of a coal-fired power plant with scrubbers for sulphur oxide removal are typically about 50% higher than a comparable heavy oil-fired facility; non-fuel operating costs of a coal-fired plant with scrubbers are also estimated at about twice those of oil-fired plants.

Table 3.17 LONG-RUN ELASTICITIES OF INTERFUEL SUBSTITUTION IN THERMAL ELECTRICITY GENERATION--WEPM AND OTHER STUDIES

	WEPM /a	Griffin /a (1979)	Hudson & Jorgenson (1974)	Atkinson & Halvorsen (1976)
ε_{CC}	-1.10	-1.08	-0.45	-1.15
ε_{GG}	-0.90	-1.60	-0.10	-1.43
ε_{OO}	-1.30	-1.56	-0.88	-1.50
ε_{CG}	0.14	0.01	-0.20	0.45
ε_{CO}	1.06	1.07	0.43	1.01
ε_{GO}	0.43	1.57	0.20	0.76

Memo Item: Lag Structure

ω_1	ω_2	ω_3	ω_4	ω_5	ω_6	ω_7	ω_8
0.025	0.045	0.065	0.080	0.090	0.095	0.100	0.110
ω_9	ω_{10}	ω_{11}	ω_{12}	ω_{13}	ω_{14}	ω_{15}	ω_{16}
0.100	0.095	0.090	0.080	0.065	0.045	0.025	0.015

/a Evaluated at the following cost shares (averages of industrial countries, 1955-72): S_C=0.437, S_G=0.13, S_O=0.433.

with these findings. 1/ The own-price elasticity for natural gas is assumed at a substantially lower level than those of Griffin and others. Policies are in place in the industrial countries to channel natural gas to the premium

1/ Griffin's (1979) model, using pooled cross-sectional, time-series of industrial countries, revealed long-term own-price elasticities for petroleum and natural gas in the neighborhood of -1.6, and -1.08 for coal. The own-price elasticities estimated by Hudson and Jorgenson (1974) from a time-series sample of the United States, were much lower: -0.45 for coal, -0.10 for natural gas and -0.88 for petroleum. Results by Atkinson and Halvorsen (1976) are unusual in that they were obtained from a cross-section of US power plants with capabilities to burn at least two kinds of fuels. Their own price elasticity estimates, however, are not much different from those of Griffin.

uses and away from the thermal power sector. This could cause problems for the oil-exporting developing countries where utilization of natural gas is promoted. This problem is alleviated for the most part in the model by assuming that these countries will maintain heavy price controls on natural gas in order to stimulate its consumption.

In the case of three fuel inputs in the translog fuel substitution model, the set of own-price elasticities imply all the cross-price elasticities. As before, let us examine the pattern of substitution that is likely to result from an increase in the price of petroleum. Griffin's estimates suggest that a 10% increase in petroleum price will increase the demand for coal by 10.7% and natural gas by 15.7%. At the 1978 fuel shares in North America, for example, this translates into shares of 71% for coal and 29% for natural gas as substitutes for petroleum. Although coal is recognized as the dominant substitute for petroleum, the role taken by natural gas is still sizable.

The scope for fuel switching in the short run, particularly to coal, is likely to be small, even after counting the possibility of indirect substitution through adjustments of capacity utilization rates of different units. 1/ Most of the thermal power plants which had converted from coal to oil or natural gas before 1973/74 have already switched back to coal, capitalizing on the infrastructure already in place. Given sufficient economic incentive, it is to be expected that most of the power plants currently using hydrocarbon fuels will eventually convert to coal, unless restricted by environmental problems.

1/ A small proportion of thermal power plants can use more than one fossil fuel, primarily either heavy fuel oil or natural gas.

Annex 3.1

DATA SOURCES AND LIMITATIONS

The three essential sets of data for the energy demand model are data on sectoral consumption of energy, energy product prices paid by sectoral end-users, and sectoral value-added. The sectoral energy consumption data for the OECD countries are taken from the OECD/IEA, Energy Balance of OECD Countries, for the 1960-78 period. These are sectoral data by fuels, aggregated into oil equivalents on the basis of comparable heat values. For the majority of developing countries, sectoral consumption data are not available on a consistent and long historical basis. The International Energy Agency conducted a study of sectoral energy consumption of developing countries and produced a report, Workshop on Energy Data of Developing Countries, which covers 16 developing countries for the 1967-77 period. The format and the method of fuel conversions are the same as for the OECD energy balances. These 16 countries, together with Greece, Portugal, Spain and Turkey taken from Energy Balance of OECD Countries, form the basis for sectoral consumption data for developing countries. The sectoral shares of fuels are calculated for the 20 countries with sectoral data. These shares are applied to the consumption totals by fuels obtained from the United Nations data (United Nations, World Energy Supplies, Series J, data tape). The result is sectoral consumption by fuels for the 1967-77 period. The data for 1978 were estimated using the 1977 shares.

Annex Table 3.1 shows the importance of the 20 developing countries with sectoral information in terms of the percentage of regional primary energy consumption covered by these countries. Since the countries with sectoral data are relatively large countries, the coverage is substantial.

The data on energy prices to final users are not readily available from published sources. The US Department of Energy compiled the price data for the OECD countries by end-use fuels. On the basis of this data, the energy price series for Western Europe are constructed from those of five major European countries (France, United Kingdom, Federal Republic of Germany, Italy and Netherlands). Revised and updated data provided by the US Department of Energy were used for the United States. The US Department of Energy data were also used for Canada and Japan. Data for Australia were obtained from an Australian government agency.

Annex Table 3.1: SIGNIFICANCE OF THE DEVELOPING COUNTRIES WITH SECTORAL CONSUMPTION DATA

	Total Number of Developing Countries	Number of Countries with Sectoral Data	Percentage of Primary Energy Consumption Accounted for by Countries with Sectoral Data
CSEX	8	2	70
CDOP	6	4	96
NOEX	12	2	74
OIDC	116	12	62
Total Developing Countries	142	20	65

Source: Derived from OECD/IEA, Workshop on Energy Data of Developing Countries, Vol. 2, 1979 and Energy Balances of OECD Countries, various issues; The United Nations, World Energy Supplies, Series J, data tape.

Energy price data for developing countries are hard to obtain. The Bank's resident missions provided reasonable sets of data for India, Pakistan, Bolivia, Colombia, Bangladesh, Senegal, and Ivory Coast. Data on Spain, Turkey, Greece and Portugal came from the US Department of Energy data file. National statistics were the source of data for Malaysia, Syria, Philippines, Brazil, Nigeria and Mexico. For petroleum product prices, the International Petroleum Annual provided the bulk of information. In addition to the above, we relied on various World Bank documents and other publications. Despite the amount of effort already devoted to this subject, the developing countries' energy price data leave a lot to be desired. A more systematic effort is required to cover the majority of developing countries as well as to validate the quality of existing data.

IV. SUPPLIES OF CONVENTIONAL AND NONCONVENTIONAL ENERGY

Modeling of the energy supply industries is in its infancy. In models of global energy markets, the supply side has been handled either in a cursory manner or assumed exogenously. For example, Blitzer, et al. (1975), Kalymon (1975) and Kennedy (1974) represent non-OPEC petroleum supplies as a function of the price of crude petroleum, with a constant elasticity. This approach not only relies too heavily on a few parameters, but also ignores the effects of resource exhaustion on supplies. More rigorous petroleum supply models have been developed by Eckbo, Jacoby and Smith (1978) and Fisher (1974) on the basis of detailed well-by-well data on existing fields (for example, North Sea and the United States). Since the results of these studies are highly area-specific, it would be difficult to extrapolate them to other potential areas of petroleum supplies.

In WEPM, the non-OPEC supplies of conventional petroleum and natural gas are treated exogenously. Supply uncertainties are dealt with by analyzing sensitivities of market adjustments to alternative supply scenarios. An attempt has been made to develop a non-OPEC petroleum supply model for WEPM, following the approach taken by Adelman and Paddock (1980) in connection with the MIT Oil Project. After further refinements, we plan to incorporate this into WEPM.

The proven reserves of coal, which amount to more than 200 times the current rate of consumption, will be the source for the bulk of coal supplies in the foreseeable future. This substantially reduces the degree of uncertainty of future supplies and costs. Supply costs for the proven coal reserves in the United States, the largest coal producer, were analyzed by ICF Inc. (1980), M. Zimmerman (1981) and Charles River Associates (1977). Results from these and other studies form the basis for the long-run coal supply model presented here.

Supplies of hydro and nuclear electricity and nonconventional energy sources such as liquid fuels from heavy oils, tar sands, oil shale, and coal are treated exogenously in the model. Prospects for nonconventional energy supplies, heavily dependent on government subsidies, have deteriorated

drastically in the recent years. The last two sections of this chapter deals with the supply issues of these energy sources.

4.1 Conventional Petroleum and Natural Gas

Table 4.1 sets out the base-case projections of hydrocarbon supplies of the non-OPEC regions. These projections are closely in line with the recent assessments of the supply prospects made by national and international agencies and the multinational oil companies. Similar projections done in the past consistently turned out to be overly optimistic, attesting to the degree of uncertainty and bias associated with such projections.

Table 4.1: BASE-CASE PROJECTIONS OF PETROLEUM AND NATURAL GAS SUPPLIES (MBDOE)

	Petroleum					Natural Gas		
	1985	1990	2000	Simulation for 2000 /a		1985	1990	2000
				Base	Optimistic			
NOAM	10.14	9.58	9.60	7.89	8.94	9.80	9.20	8.44
WEUR	3.30	2.76	2.50	1.92	1.87	3.15	2.88	2.40
JANZ	0.43	0.50	0.98	0.48	0.72	0.55	0.60	0.72
NOEX	6.00	7.40	8.50	4.79	7.24	1.54	1.94	3.00
OIDC	2.10	2.80	3.50	1.43	1.37	1.10	1.37	2.10

/a Simulation results of the petroleum supply model.

Source: World Bank, Economic Analysis and Projections Department.

Instead of trying to substantiate the base-case projections, we compare them with the preliminary simulation results of the non-OPEC petroleum supply model currently under development. The supply simulation up to the year 2000 is done under two different assumptions about the ultimately

recoverable resources of petroleum. 1/ The base-case simulation postulates that the ultimately recoverable resources in non-OPEC market economy countries amount to 690 billion barrels, including 190 billion barrels of cumulative production as of end of 1980 and 130 billion barrels of proven reserves as of the same date. This corresponds roughly to the median of the range of available estimates of ultimately recoverable resources of petroleum. The optimistic case assumes that the ultimately recoverable resources are 50% higher than the base case.

For the medium term up to 1990, the exogenous supply projections of petroleum are not much different from the base-case simulation results of the supply model. However, the base-case exogenous supply projections for the year 2000 are higher than even the optimistic-case simulation results of the supply model for the same year. Implications of this are two-fold: (a) the ultimately recoverable resources should be substantially higher than the available estimates, in order to sustain a level of production to the year 2000 equal to or higher than that of 1990: and/or (b) producers would have to step-up drilling and production to faster rates than in the recent past, regardless of the fact that this will result in faster exhaustion of the resource. Unless one can place a good deal of confidence in one or both of these possibilities, the exogenous supply projections for the long term should be considered optimistic.

4.2. Coal Supplies and Costs

Production and Reserves

The main advantage of coal is its relative abundance compared with petroleum and natural gas: proven recoverable reserves of coal worldwide amount to more than 200 times the current annual production (Table 4.2). Characteristics of the proven reserves, which are reasonably well known in the

---

1/ The ultimately recoverable resources include cumulative production, proven reserves, probable additions to reserves in known fields, and expected discoveries. As such, estimation of its magnitude is basically a matter of speculation.

key producing countries, will be the key factor in determining the future availabilities and costs of coal in the international market. 1/

World coal production today is concentrated in a few countries. Close to two-thirds of world production takes place in the United States, the U.S.S.R. and the People's Republic of China. Other important coal producing countries are Australia, Canada, South Africa, Poland, India, United Kingdom and Federal Republic of Germany. Important coal exporters are the United States, Australia, Poland and South Africa. Potential new exporters include Colombia, Canada, Indonesia and Botswana.

Only a small number of countries have data on proven reserves of metallurgical coal. The total of these reserves (75 billion tons) amounts to 18% of the world's proven recoverable reserves of anthracite and bituminous coals. About 20% of the proven recoverable reserves in the United States is metallurgical coal. In Australia and West Germany metallurgical coal reserves are close to 60% of their total bituminous coal reserves, while South African coal is mostly non-metallurgical.

The WEPM coal supply model distinguishes between underground and open-cast (surface) coal mining because of their widely different cost structure. Production costs of open-cast mines are usually substantially lower than those of underground mines due to higher labor productivity, greater economies of scale and faster development. This production cost differential has led to a steady shift to open-cast mining in almost all countries with coal resources which can be surface mined. Table 4.2 shows

---

1/ There are three broad categories of coal: anthracite, bituminous and sub-bituminous coal, and lignite, classified according to the degree of carbonization. Slightly more than 5% of world coal production consists of anthracite, about 69% of bituminous coal and the remaining 26% of lignite. Compared to bituminous coal and lignite, anthracite has the advantage of being a clean-burning fuel. Bituminous coal has a higher heat value than sub-bituminous coal and lignite. Some bituminous coals have "caking" properties when heated in the absence of air. These are known as coking or metallurgical coal. About 27% of the coal produced outside the centrally planned economies consists of metallurgical coal. The non-coking coal is also known as steam or thermal coal. Technological advances have made it possible to blend to some extent coking and non-coking coals in production of cokes. Coking coal commands substantially higher prices than thermal coal because of its coking property.

Table 4.2: WORLD COAL RESERVES AND PRODUCTION

(billion tons of coal equivalent)

	Proven Recoverable Reserves		Production, 1978	
	Hard Coal /a	Total	Total	Percent from Open-Case Mines
NOAM	121.9	187.0	0.602	56
WEUR	71.0	81.5	0.284	7
JANZ	19.2	28.5	0.107	33
CSEX	0.2	0.2	0.001	0
CDOP	1.1	2.5	0.001	0
NOEX	1.0	1.0	0.005	0
OIDC	70.9	86.7	0.227	23
Total above	285.3	387.4	1.227	36
Centrally Planned Economies	205.8	246.7	1.507	

/a Hard coal is broadly defined to include authracite, bituminous and sub-bituminous coal.

Source: World Energy Resources 1985-2020, published for the World Energy Conference, IPC Science and Technology Press, 1978.

that about 36% of world coal production in 1978 came from open-cast mines. Only a small number of countries have estimates of proven reserves of coal which can be surface mined: about 26% of the US proven reserves, 45% in South Africa and 24% in Australia.

The coal mining industry is basically competitive in the main coal producing industrial countries. In the United States, for example, there are more than 3,000 coal mining companies producing coal. 1/ The situation is

1/ The top 15 coal-producing companies in the United States accounted for 41% of the country's total bituminous coal production in 1977, and the top 50 companies produced 65% of the total. Keystone Coal Industry Manual, 1978 Coal Mine Directory (New York, N.Y.: McGraw Hill, 1978), p. 318.

similar in Australia, canada and South Africa. In other major coal producing countries, the industry is either a part of the public sector (the United Kingdom, India and the centrally planned economies) or is subject to government participation and control (Federal Republic of Germany, Republic of Korea, and many Western European and developing countries). Government intervention in the coal industries of Western Europe and Korea is largely a result of the need for government subsidies to compensate for their high costs of production.

Coal Cost Structure and Long-term Coal Supply Model

The economic theory of exhaustible resources tells us that extraction of the resource will proceed from low-cost deposits to high-cost deposits. 1/ In the absence of cost-saving technical progress, therefore, the cost of coal production can be expected to rise over time.

It is reasonable to postulate that coal resources provided by nature have a normal distribution with respect to mining costs. Integration of the normal distribution function yields a relationship that specifies the cost of mining as an increasing function of cumulative production. This provides the conceptual basis for the long-term coal supply model. The countries with substantial past production in relation to total resources would have relatively high production costs and the cost of extraction from the remaining resources can be expected to increase faster. The countries with relatively low mining costs (e.g., the United States, Australia, and South Africa) would have large remaining resources at relatively low costs

The price of coal to the end-users or at the export terminal includes the costs of mining, preparation (upgrading), transportation, and taxes and royalties. The price of coal, FOB mines, usually includes all of the above except the cost of transportation. Mining costs differ widely between countries and mining regions, depending on the type of coal deposits, factor prices, and the mining technique. Table 4.3 shows the range of mining cost estimates for the important coal producing countries. The average mining cost

---

1/ The cost here includes not only the mining costs but also the costs of bringing the coal to final users.

Table 4.3: ESTIMATES OF COAL MINING COSTS /a

	Underground Mines	Open-Case Mines	Year of Estimation	Data Source
United States				
Appalachia	20-25	15-20		
Midwest	25-30	12-16	1978	Skelly and Loy
West		8-12		
Canada	20-25	5-7	1975	Skelly and Loy
Australia	25-30	25-30	1980	World Bank
South Africa	10-15	10-15	1980	World Bank
India	10-25	5-10	1980	World Bank
United Kingdom	40 /b		1978	IEA
Germany, F.R.	60-70		1977	IEA

/a Per ton of salable hard coal basis, including the costs of mining, depreciation, normal returns on investments and coal preparation, but excluding taxes and royalties.

/b Average cost of underground and surface mined coals.

Sources: IEA, Steam Coal: Prospects to 2000, OECD, Paris, 1978. Skelly and Loy, "World Coal Supply Forecast," Report to the World Bank. "India: Coal Sector Survey" August 1981, and other World Bank mission reports.

of the major coal exporting countries (the United States, Australia and South Africa) is typically less than half of that of the high-cost producers.

The cost of mining is heavily affected by geological conditions. In underground mining it depends on the thickness, depth and grade of coal seams, roof and floor conditions, complexity of geological structure, extent of water and methane presence, etc. In open-cast mining the key factor is the ratio of overburden thickness to that of coal seam.

Open-cast mining involves more capital and less labor than underground mining. Mining costs of an open-cast mine could be as low as half of those of an underground mine. Table 4.4 shows a breakdown of mining costs in selected countries in terms of three broad cost categories: labor, capital and materials. As a rule of thumb, the cost of labor is approximately 50% of the total mining costs of underground mining in industrial countries. In the case of developing countries, the cost share of labor can be higher (e.g., India) or lower (e.g., South Africa) than in the industrial countries. In the case of open-cast mining, the cost share of labor is typically 15-20%, and that of capital around 40-50%. An upshot of this data appears to be that labor and capital are highly substitutable in coal mining, although productivity of capital is such that under a relative factor price configuration, such as that in South Africa, fairly capital intensive mechanized mining could be the preferred choice if coal deposits are suitable for such mining methods.

Assuming constant factor prices and no technical progress in mining, Zimmerman (1981) developed a long-run coal supply model for the United States. His model is based on the known characteristics of the proven reserves in the United States. Using historical and engineering data, Zimmerman (1981) found that coal output per production unit 1/ is heavily influenced by seam thickness in the case of underground mining and by the ratio of overburden to seam thickness in open-cast mining. Other unknown geological factors collectively are treated as a random variable in his analysis. Zimmerman found that resource depletion and concomitant reduction in seam thickness in underground mining could result in a more than proportional decline in mine productivity. His results also indicate that the left-out geological factors could have a significant but essentially random impact on

---

1/ An underground mine usually consists of a number of mining sections as production units, where a fixed proportion of labor and capital work on the seam surface under a given mining technology. The predominant underground mining technology in the United States is continuous mining where removal of coal from seam and loading to conveyor are done in a continuous process. The dragline is the most commonly used equipment for overburden removal in open-cast mining. The dragline capacity, measured by the maximum usefulness factor, is the production unit used in his analysis.

Table 4.4 COMPOSITION OF COAL MINING COSTS

	Percent Share of		
	Capital	Labor	Materials
United States (1977)			
Open-Cast Mines			
Appalachia	52	21	26
Midwest	51	18	31
Montana-Wyoming	39	16	45
Underground Mines			
Appalachia	24	50	26
Midwest	24	50	26
West	19	50	31
South Africa			
Underground Mines	55	14	32
Open-Cast Mines	70	6	24
Australia			
Underground Mines	24	45	31
Open-Cast Mines	49	20	31
United Kingdom (1978-79)			
NCB Average (91% Underground)	22	51	27
India (1979-80)			
CIL Average (65% Underground)	13	61	26

Sources: United States: Martin B. Zimmerman, The U.S. Coal Industry, The MIT Press, 1981.

United Kingdom: Colin Robinson & E. Marshall, What Future for British Coal, The Institute of Economic Affairs, London, 1981, p. 51.

Australia, India & South Africa: World Bank.

mine productivity, and that there is diminishing returns to scale due to congestion and increased travel time at the mine site. He found increasing returns to scale in open-cast mining.

Zimmerman estimates the long-run marginal cost curve (the long-run supply curve) for underground mining as a function of seam thickness under the assumption of constant factor proportions and factor prices. The long-run marginal cost is the minimum average cost of a new mine. Diminishing returns to scale in underground mining enable one to establish the minimum efficient scale of new mines. In open-cast mining, the minimum average cost is not defined because of increasing returns to scale. Zimmerman uses an estimate of the maximum size of prospective new open-cast mines for the major producing regions.

Derivation of a long-run coal supply function as a function of cumulative production requires a forecast of seam thickness and overburden ratio. To do this, Zimmerman uses the US Geological Survey data which show US proven coal reserves in seams between 28 and 42 inches and those greater than 42 inches thick. Data on distribution of overburden ratio in Montana and Illinois are taken to be representative of the west and the midwest, respectively.

The resulting long-run coal supply function for the United States estimated by Zimmerman is reproduced in Table 4.5. In the east and midwest, where the demand for coal is concentrated, high sulfur coal is the least expensive type of coal available over the long run. Low sulfur coal can be mined from the western states without significant cost increases for a long time, but must be transported over a long distance to reach the consumption centers. Low sulfur coal accounts for about 46% of the demonstrated coal reserve base of the United States, but only 16% of the low sulfur coal is located east of the Mississippi River. Currently, about 29% of coal produced in the United States is eastern low sulfur coal.

Because of the wide regional differences in costs and sulfur content of coals, the long run coal supply curve for the United States as a whole depends on the future mix of supplies from different regions. WEPM, however, lacks the capability to model interregional competition in coal supplies, or determine the relative shares of underground vs. open-cast production.

Table 4.5: ESTIMATED PERCENT COST INCREASES OVER TIME AT THE 1976 RATES OF PRODUCTION IN THE UNITED STATES

	5 Years	10 Years	20 Years	30 Years	50 Years
Underground Mines					
Northern Appalachia					
Medium Sulfur	4.5	8.6	17.0	25.0	41.0
High sulfur	2.3	5.2	10.0	15.0	24.9
Southern Appalachia					
Low Sulfur /a	7.9	15.0	31.8	51.2	98.6
Medium Sulfur /a	6.9	13.2	25.7	40.9	68.0
High Sulfur /a	2.9	5.9	11.4	16.8	29.6
Midwest					
High Sulfur	0.6	1.5	2.7	4.1	6.9
Open-Case Mines					
Midwest					
High Sulfur	10.1	15.6	25.7	-	-
Montana-Wyoming /b					
Low Sulfur	1.3	2.5	8.2	-	-

/a Generally, low sulfur coal has less than 1% sulfur by weight, high sulfur coal has more than 3% sulfur, and medium sulfur coal between 1 and 3%.

/b At five times the 1976 production level.

Source: Martin B. Zimmerman, The U.S. Coal Insdustry: The Economics of Policy Choice, The MIT Press: Cambridge, Mass., 1981, p. 62.

Assumptions must be made about the future interregional mix of production on the basis of available information. Zimmerman (1981) developed a linear programming interregional competition model, which indicates that US coal production will continue to shift from the eastern underground mines to the western surface mines, even under a wide range of assumptions about environ-

mental controls and transportation costs. The net effect of this shift would be lower average long-run costs than otherwise. To estimate the long-run supply curve for the United States as a whole, we use Zimmerman's results on regional production shares from his interregional competition model, under the assumptions of constant factor costs, small increases in the cost of transporting the western coal to the east, and stringent anti-pollution measures stipulated under the current laws. 1/

Estimates of the long-run coal supply function are only sketchy at this time for other major coal producers. Mining costs in Australia and Canada can be expected to follow a path similar to that of the United States. 2/ The cost of mining in South Africa is lower than in other countries, partly because of the country's relatively low wage rate. One recent estimate indicates about 0.5% p.a. real increases in the FOB mine costs of South African coal during the 1980s. 3/ Information on coal resources and costs in other developing countries are only beginning to appear. It is likely that some of the newly emerging coal producing developing countries will be cost competitive with the United States. The high-cost producers--Western Europe, Japan, and the Republic of Korea--will certainly face much faster cost increases.

Coal qualities and costs do not show wide regional differences in countries other than the United States, except perhaps for Canada and Australia. A choice between underground vs. surface mining could be important, but the share of open-cast production has been increasing steadily over the past decade wherever coal that can be mined using open-cast methods is available, even in countries such as India where relative factor prices may suggest otherwise.

1/ The scenario assumes sulfur standard of 1.2/lb. and BACT (Best Available Control Technology)

2/ See, for example, J.K. Doherty, "Producer's View--Australian Steaming Coal," in Pacific Rim Coal Trade Conference, January 1982.

3/ R.B. Olliver, "Steam Coal in Southern Africa," EIU Special Report No. 122, Economist Intelligence Unit, London, April 1982.

The above considerations, together with the estimates for the United States, are reflected in the WEPM base-case assumptions about the long-run cost curve and production shares shown in Table 4.6. The cost is on an FOB mine basis, except that the cost of US western coal includes the transportation cost from western mines to eastern markets. The shares of open-cast production by the year 2000 for country groups other than North America are assumed, taking into consideration historical trends and estimates of surface-minable coal reserves of the major countries. The oil-exporting developing

Table 4.6: LONG-RUN COST FUNCTION AND PRODUCTION SHARES OF COAL

	Estimated 1978 Costs (1981$/ton)	Long-run Cost Function /a	Production Shares in 2000 (%)
NOAM			
Underground	34.7	0.68	30
Open-Cast	21.4	0.47	70
WEUR			
Underground	75.9	1.00	90
Open-Cast	28.1	0.80	10
JANZ			
Underground	38.0	0.68	35
Open-Cast	18.6	0.50	65
OIDC			
Underground	28.7	0.75	60
Open-Cast	16.9	0.60	40

/a Expressed as percent cost increases per year at 1978 rates of production.

Source: World Bank, Economic Analysis & Projections Department.

countries are assumed to follow the same pattern of long-run cost increases as the oil-importing developing countries.

The long-run coal supply function is expressed as:

$$SDC_t = \left(\frac{PSDC_t}{PSDC_{78}} - 1\right) / (ASG/SDC_{78}),$$
$$UDC_t = \left(\frac{PUDC_t}{PUDC_{78}} - 1\right) / (AUG/UDC_{78}), \qquad (4.1)$$

where SDC_t and UDC_t are production in year t from open-cast and underground mines, respectively; $PSDC_t$ and $PUDC_t$ are the respective production costs; ASG and AUG are the respective annual rates of cost increases at the rate of production in 1978; and SDC_{78} and UDC_{78} are the respective actual production in 1978. The relevant base-case parameters and assumptions of the long-run supply curve are shown in Table 4.6.

Factor Prices and Productivities

The long-run cost function in Table 4.6 assumes that factor prices and factor productivities will remain constant. This assumption is hardly a realistic one. Of particular importance in the case of coal mining is the cost of labor and labor productivity. Underground coal mining is one of the most dangerous occupations; health and safety issues complicate the analysis of mining wages and labor productivity. Recent historical records are shown in Table 4.7. In the United States during 1968-78, for example, coal mining wage rates increased 2% faster annually than the manufacturing wage rate (despite an average annual decline of 6% in labor productivity in underground mining) partly as a result of the Coal Mine Health and Safety Act of 1969. Rents generated by oil price increases stimulated mining wage rate increases in virtually all major coal producing countries. Labor productivity improved significantly in Australia and South Africa, however, in connection with capacity expansion that took place in those countries.

In the absence of a full-fledged model of the coal industry labor market, it is difficult to incorporate all the relevant considerations in the determination of the coal mining wage rate into the long-term coal supply model. As a short-cut measure, we assume that the coal mining wage rate (MWR) will increase at the same rate as the per-capita GDP:

Table 4.7: MINING WAGES AND LABOR PRODUCTIVITY OF MAJOR COAL PRODUCING COUNTRIES

	Mining Wages (A)	Consumer Price Index (B)	Real Mining Wage Rate A/B x 100	Output per Man-Shift Under-ground	Output per Man-Shift Open-Cast
	(US$/hour)		(US$/hour)	-------(tons)--------	
United States					
1968	3.86	53.3	7.24	15.40	34.24
1973	5.75	68.2	8.43	11.66	36.30
1978	9.57	100.0	9.57	8.25	25.00
Australia	(A$/week)		(A$/week)		
1966-67	98.0 /a	50.0 /a	196.0 /a	8.63	21.54
1973-74	160.0	67.4	237.4	9.55	33.68
1977-78	308.0 /b	100.0 /b	308.0 /b	10.06	30.16
U.K.	(£/hour)		(£/hour)		
1968	0.61	33.1	1.84	2.12 /c	
1973	1.06	47.5	2.23	2.29 /c	
1978	3.05	100.0	3.05	2.25 /c	
South Africa /d	(Rand/year)		(Rand/year)		
1970	530.9	47.1	1127.2	1030.0 /e	
1974	1083.5	64.7	1674.7	1290.0 /e	
1978	2563.7	100.0	2563.7	1390.0 /e	

/a For 1969-70
/b For 1976-77
/c Average output per man-shift for all National Coal Board collieries.
/d For Transvaal and Orange Free State
/e Output per man-year.

Sources: U.S. Bureau of Mines, Bituminous Coal and Anthracite, various issues;
U.K. Department of Energy, Digest of Energy Statistics, 1981;
Joint Coal Board, Black Coal in Australia, 1977-78, A Statistical Year-Book;
R.B. Olliver, Steam Coal in Southern Africa, 1982.

$$MWR_t = A_0 \cdot (GDP_t/POP_t) \qquad (4.2)$$

where A_0 is a constant representing the base-year relationship.

This relationship assumes that there is sufficient labor mobility between the coal mining industry and the rest so that wage rates will be equalized for comparable skills and hardship. It also assumes that the average wage rate will increase at the same rate as the per capita value-added. Compensation for health and safety risks included in MWR is assumed to increase at the same rate as per capita income. This formulation ignores the possibility of benefiting from economic rents that may be generated from future oil price increases. Although the recent historical data does support this possibility in the short run, its sustainability over the long run is doubtful.

Most of the gains in labor productivity in coal mining were achieved through substitution of capital for labor. In the industrial coal-producing countries, labor productivity (output per man-shift) improved substantially in the 1950s and early 1960s when new mechanized mining technologies were introduced. In the late 1960s and during the 1970s, labor productivity either remained stagnant or declined. 1/ Given the productive efficiencies already achieved, further substantial cost-saving technological advances are not expected in the industrial coal producing countries. Developing countries, on the other hand, have the potential to substantially improve labor productivity from their current low levels. It is not clear, however, to what extent this will contribute to an overall cost reduction, because this will involve concomitant increases in capital costs. This is an area that needs to be investigated in future refinements of the coal supply model as more information becomes available.

1/ As pointed out previously, Australia and South Africa appear to be exceptional in this regard, primarily because of the fact that these countries became major coal producers only recently.

The long-run coal supply model assumes that the real costs of capital and materials will remain constant at their base year levels. During the 1970s the price of mining machinery increased faster than the rate of inflation. In the United States, for example, the price of mining machinery increased almost twice as fast as the GNP deflator. This phenomenon is considered transitory.

Short-term Dynamics and Capacity Expansion

In the short run the coal supply industry operates along the short-run supply curve, which is defined by the marginal cost curve for given production capacity. As with other mining industries, production above the normal capacity requires steeply rising costs. It is postulated that the short-run supply function takes the form:

$$DCOAL_t = A_0 \cdot PCOAL_t^{\alpha} \qquad (4.3)$$

where DCOAL and PCOAL stand for domestic production of coal and its FOB mine price respectively, A_0 is a constant, and α is the short-run price elasticity of supply. Coal supply is assumed to take place along the short-run supply curve whenever demand exceeds production capacity by more than 5% in any year.

The short-run elasticity should be estimated from data for the period when the industry produced beyond the normal production capacity and can reasonably be presumed to have operated along the short-run supply curve. The period following the 1979-80 petroleum price increases would be a good example of this, but the period is too short for a meaningful statistical analysis. Instead, the following calculation gives the rough order of magnitude: between 1979 and 1981, the US export price of thermal coal increased by 50%, while US exports of coal increased by 70%. This would suggest a short-run export supply elasticity of around 1.4, not counting the fact that the industry had significant excess capacity in 1979. As a first approximation, we assume that $\alpha = 1.0$, which results in a reasonably close replication of the recent price movements.

Capacity expansion links the short-run equilibrium with the long-run adjustments. Any excess demand and higher prices in the short run will lead

to investments in new mining capacity, and an eventual return to the long-run relationship. The investment function is assumed to take the form:

$$CCAP_t = A_t \quad PDCOAL_{t-3}^{\alpha_1} \quad PDCOAL_{t-4}^{\alpha_2} \quad PDCOAL_{t-5}^{\alpha_3} \qquad (4.4)$$

where $CCAP_t$ is the coal capacity addition in year t, PDCOAL is the mine price of coal and A_t is a constant for the year t. The constant term, A_t, is used to account for the trend growth in coal production. This formulation is based on the simple assumption that investment decisions are made solely on the basis of current coal prices. The lags in coal prices reflect the normal gestation period required for an investment to come on stream. The elasticities of investments with respect to the lagged prices (α_i's) are calibrated so that, whenever there is an excess demand and the industry operates along the short-run supply curve, there will be enough investments to eliminate the excess demand and return to the long-run supply curve in five years.

Other Related Costs

Important cost items related to coal production are taxes, costs of environmental reclamation and coal transportation. Changes in these items are equivalent to a shift in the long-run supply curve.

Severance tax is a way of taking away part of the economic rent accruing to the low cost suppliers. Montana has a 30% severance tax and Wyoming is considering an additional 5% tax on top of its existing 16.5% tax. Other western states are likely to follow suit. Australia imposes a $6 export tax on hard coking coal. In Canada, the provinces of British Columbia and Saskatchewan have royalty rates of 3.5% and 15% respectively, while Alberta has variable royalty rates depending on production costs.

Environmental damage caused by coal mining add to the cost of mining. In the United States, the Surface Mining Control and Reclamation Act of 1977 calls for restoration of strip-mined land to conditions as valuable as the use before mining. This requires restoration of the land to its original contour, to the extent possible, and revegetation. Estimates of reclamation costs vary widely: the cost is small in flat terrains of the western United States if rainfall is also adequate (US$0.15 - US$0.90 per ton in 1977), but

quite high in the hilly areas of Appalachia ($3.00 per ton). The law also stipulates a reclamation fee for old abandoned mines to be collected from current producers ($0.35 per ton of hard coal and $0.10 for lignite). Land subsidence problems associated with underground mining have been ignored in the past. One way of dealing with this problem is to leave coal pillars underground, which reduces the recovery factor and therefore the cost per ton of recovered coal. The total cost of abatement of damages from old abandoned mines in the United States is estimated to run to billions of dollars. Part of the cost is to be borne by a reclamation fee of $0.15 per ton levied on active underground mines. Coal mining also causes pollution of underground aquifers and streams, air pollution from coal dust and the thermal drying of washed coal, and problems of waste disposal from cleaning of raw coal. Existing costs are already reflected in the current costs of mining; further increases in these costs will be equivalent to a shift of the long-run supply curve.

Transportation costs make up a large part of the price of coal to final users. Railroads are in a position to take advantage of any temporary rise in coal prices by raising freight rates. The WEPM coal supply model assumes that transportation costs will remain constant in the years ahead, except for the small cost increases assumed for transporting western coal to the eastern markets in the United States.

4.3. Hydro and Nuclear Electricity

In WEPM, the primary electricity supplies (hydro/geothermal and nuclear electricity) are treated exogenously. Table 4.8 shows the base-case projections. Supplies of nuclear electricity now clearly involve more than economic issues; this applies to a lesser degree to hydroelectricity supplies. For this reason, the competition between the primary and the secondary (thermal) sources of electricity generation cannot be dealt with purely on economic grounds.

A study of hydraulic resources conducted for the World Energy Conference (1978) pointed out that only 16% of the installed and "installable" hydraulic energy resources worldwide is currently being tapped. About 46% of hydroelectric potential is being utilized in the industrial countries, while for the developing countries as a whole only 7% of the potential is being

Table 4.8: BASE CASE SUPPLIES OF HYDRO/GEOTHERMAL AND NUCLEAR ELECTRICITY (MBDOE) /a

	Hydro/Geothermal Electricity					Nuclear Electricity				
	Annual Growth Rates 1968-1978	Actual 1978	Projected 1985	Projected 1990	Projected 2000	Annual Growth Rates 1968-1978	Actual 1978	Projected 1985	Projected 1990	Projected 2000
NOAM	3.7	0.905	0.99	1.11	1.21	36.4	0.558	0.64	1.03	2.09
WEUR	2.3	0.615	0.69	0.74	0.78	34.7	0.275	0.44	1.00	1.21
JANZ	1.9	0.184	0.24	0.30	0.36	48.2	0.102	0.13	0.30	0.78
CSEX	16.8	0.007	0.02	0.02	0.02	-	0.000	0.00	0.02	0.02
CDOP	14.4	0.031	0.06	0.07	0.09	-	0.000	0.00	0.00	0.00
NOEX	7.0	0.065	0.11	0.13	0.15	-	0.000	0.00	0.01	0.02
OIDC	8.9	0.542	0.90	1.19	1.48	33.3	0.025	0.09	0.29	1.02
Total	4.2	2.349	3.01	3.56	4.09	32.8	0.960	1.30	2.48	5.14

/a Converted to oil equivalents assuming 100% conversion efficiency from thermal energy to electricity.

Source: World Bank, Economic Analysis and Projections Department.

used. In industrial countries, however, most of the favorable hydroelectric sites have already been developed and the remaining potential sites often pose problems of one sort or another. However, the steep increases in the prices of hydrocarbon fuels are likely to give new impetus to maximal utilization of hydraulic energy. One estimate for the United States shows that small scale (low head) hydroelectric projects and rehabilitation, expansion, and installation of generators at existing dams could add 55 GWe of new generating capacities, or close to 80% of existing hydroelectric capacity. New high head projects could also add as much.

Hydroelectric potentials are promising in a number of developing countries in Latin America, Africa and parts of Asia. Hydroelectric generation has been growing rapidly in developing countries, and may be expected to expand appreciably in the next two decades. Several problems, however, limit this growth. One is that electricity markets in many developing countries are not large enough to justify a large-scale hydropower project. International legal problems also stand in the way of utilization of major river systems in Africa and Latin America. Developing countries also must face the usual problems of land flooding, disturbance of natural habitat, and sedimentation. These problems and gradual exhaustion of favorable hydro resources are reflected in a gradual slowdown of the projected base-case growth rates of hydroelectricity supplies in developing countries.

Supplies of conventional nuclear electricity are now subjected to greater uncertainties than ever. The issues are concerned not so much with the economics of nuclear power but rather with its safety, nuclear waste management and weapons proliferation.

Conventional nuclear power would seem to be more economical than thermal electricity at today's fossil fuel prices. Table 4.9 shows cost estimates of nuclear power and thermal electricity under the set of conditions specific to the United States around 1977-78. It seemed at that time that nuclear electricity was more economical than coal-fired power generation with flue gas desulphurization (scrubbers). Since then, however, the safety, health and security safeguards implemented in the wake of the Three Mile Island accident have led to cost overruns in projects under construction in the United States, making the nuclear power produced by these plants far more costly than fossil fuel electricity.

Table 4.9: COST ESTIMATES FOR NUCLEAR AND FOSSIL FUEL POWERED ELECTRICITY GENERATION (in mills per Kwh)

	IEA /a Steam Coal Study	Bechtel /b Study	R. Gordon /c	US /d NRC
Nuclear	23.8	30	22.54	39.82-43.79
Fuel Oil				
Low Sulfur Conventional	40.5	53		
High Sulfur 100% FGD	42.8			
Coal				
Without FGD /e	22.6		16.73	
With 100% FGD	28.8	35	21.44	47.80-61.35
With 50% FGD	25.7			

/a International Energy Agency, "Steam Coal: Prospects to 2000," Paris, 1978, p. 50.

/b Bechtel Corporation, "Economic Review of Advanced Fuel and Power Technologies," San Francisco, 1980, Mimeo.

/c Richard L. Gordon, Coal in the U.S. Energy Market, D.C. Heath and Co., Lexington, Mass. 1978, p. 132-133.

/d Robert, J.O., S.M. Davis and D.A. Nash, "Coal and Nuclear: A Comparison of the Cost of Generating Baseload Electricity by Region," U.S. Nuclear Regulatory Commission, Washington, D.C., October 1978. For initial operation in 1990 without taxes, with nuclear fuel recycling and coal costs estimated by the US Department of Energy.

/e FGD stands for flue gas desulphurization.

The projections of nuclear electricity supplies to 1990 are largely based on a count of projects under construction or firmly committed. In the

United States, there were 55 GWe of capacity as of January 1, 1981, 73 GWe of new capacity with significant construction already completed, 20 GWe of new projects for which construction permits have been granted but without significant construction completed, and 15 GWe of new plant orders for which construction permits were under review. Some of the projects with substantial construction behind them have recently been cancelled in the United States. One cannot rule out the possibility that some existing projects under construction could be delayed beyond 1990, making projections to 1990 overly optimistic. Most of the projected nuclear electricity supplies to 1990 for Western Europe are based on the projects for which significant construction has already taken place. About two-thirds of the projected 1990 nuclear capacity for Japan represents projects that are under construction or already operational. The projections for developing countries for 1990 mostly include firmly committed projects.

The nuclear supply projections for the year 2000 are subject to more uncertainties. Recent mid-range projections by the US Department of Energy are 128 GWe for 1990 up from 55 GWe in 1980, and 175 GWe in the year 2000, while its low nuclear supply scenario foresees practically zero growth in the 1990s. The prospects for nuclear power supplies do not appear to be as bleak in other regions as in the United States.

4.4. Backstop Technologies and Costs

Evaluation of alternative sources of energy as replacements for conventional petroleum has shown a wide range of technological and economic feasibilities. Most promising from the technological and economic standpoint are synthetic liquid and gaseous fuels from heavy oil, oil shale, tar sands and coal. These have enough energy supply potential to carry the energy transition from petroleum to ultimately inexhaustible sources of energy. Moreover, their costs of supply could place the upper bound on the price of conventional petroleum during the period of such transition.

Some synthetic fuel technologies are already well established. South Africa has been operating two coal liquifaction facilities (SASOL I and II) and is expected to add another (SASOL III) in 1985, when the total capacity will reach 70,000 b/d of liquid fuels. In the context of the South African

economy, the SASOL projects appear to be economically viable. 1/ This experience, however, would not necessarily be applicable to other countries with potential for coal liquification. South Africa probably has the lowest price for coal and is less constrained by environmental regulation.

Canada is currently producing synthetic liquid fuels from tar sands with a capacity of slightly over 110,000 b/d. Operational experience of Syncrude Canada thus far appears to demonstrate its profitability at $22-25 per barrel price in 1982 dollars for its synthetic crude oil. Capital costs of new tar sands projects in Canada, however, are likely to be substantially higher than the ones already operating. Furthermore, the Canadian government's heavy-handed policies on domestic crude oil pricing led to cancellation of Syncrude Canada's expansion project (Exxon's Cold Lake project) and Shell's Alsands project.

Estimates of synthetic fuel costs have undergone continuous upward revisions. Recent estimates are shown in Table 4.10. These estimates were based on engineering studies and experimental data of small-scale prototype plants, rather than actual operational experience of large scale commercial plants. As knowledge accumulated over recent years, technological and environmental problems associated with these technologies became more evident, leading to escalating cost estimates. Although this trend may continue, we assume for the purpose of WEPM simulations that the average cost of synthetic liquid fuels will be $56 per barrel in 1981 dollars. This corresponds roughly to the mid-point of the range of current estimates of synthetic fuel costs in the United States.

The future of synthetic fuel supplies will depend heavily on government policy. Many synfuel projects are likely to be uneconomical at current international petroleum prices and will require government subsidies. Table 4.11 shows the potential synfuel supplies from projects that have been

---

1/ SASOLs are 70% privately owned and traded in the Johannesburg stock exchange. They were initially financed by the government and later liquidated by selling the equities to the private sector. The government reportedly had no difficulty in recouping the initial investments by such liquidation.

Table 4.10: PRODUCTION COSTS OF SYNTHETIC LIQUID FUELS

	Bechtel /a 1979$ (per bbl)	RFF 1975$ (per MMBtu)	OGJ 1979$ (per bbl)	Exxon 1978$ (per MMBtu)
Tar Sands /b	17			
Heavy Oil /b	23			
Oil Shale /b	22	4.0-6.4	25-30	4.0-5.0
Coal Liquifaction /c	44	2.5-3.3		3.5-4.5
High Btu Coal Gasification /c	56			
Wood to Methanol	28-42			
Wood to Ethanol	32-48	9-14		

/a Includes 15% rate of return on investments after taxes.

/b Primary upgrading to synthetic crude oil.

/c Based on coal with heat combustion of 10,000 Btu/lb costed at $1.25/MMBtu delivered.

Sources: Bechtel, "Economic Review of Advanced Fuel and Power Technologies," San Francisco, California, August 1980.

Resources for the Future, Energy in America's Future, Johns Hopkins University Press, 1979.

Oil and Gas Journal, "Synfuel's Future Hinges on Capital, Cooperation," June 16, 1980.

Exxon, "Unconventional Hydrocarbons--Technical Adaptations to Changing Resources," Exxon Energy R&D Symposium (R.L. Hirsch, ed.), September, 1978.

seriously considered in about 10 countries. The United States has the most potential for synfuels. Recent softening of petroleum prices and changes in government policy led to cancellation of a number of important synfuel

projects in the United States. Western Europe cannot expect much in this area except for small amounts of coal liquifaction. Australia has oil shale and coal resources, while Japan plans to embark on coal liquifaction in Japan and abroad. Venezuela has huge heavy oil resources in the Orinoco oil belt, but is not likely to pursue a vigorous development policy until the late 1990s. Included in the net oil-importing developing countries are coal liquifaction in South Africa and possibly in India, oil shale projects in Brazil and Morocco, and Brazil's production of alcohol from biomass.

Given the uncertainties surrounding synfuel prospects, the projections in Table 4.11 should be viewed only as indicative of potential supplies under adequate government support and the expectation of steady increases in petroleum prices as envisaged in the base-case OPEC price scenario. The fact that the projected figures look optimistic under the present circumstances should not be of much concern because they will have a predictable impact on the WEPM simulation results, and sensitivities to this particular assumption can be readily investigated.

Table 4.11: WORLD SYNFUELS PRODUCTION TO YEAR 2000
(MBDOE)

	1990			2000		
	Coal Liquifaction	Others	Total	Coal Liquifaction	Others	Total
NOAM	0.18	0.45	0.63	1.20	1.70	2.90
WEUR	0.03	-	0.03	0.20	-	0.20
JANZ	0.07	0.08	0.15	0.30	0.30	0.60
CDOP	-	0.10	0.10	-	0.50	0.50
OIDC	0.15	0.05	0.20	0.30	0.30	0.60
Total	0.43	0.68	1.11	2.00	2.80	4.80

Source: World Bank, Economic Analysis and Projections Department.

V. SIMULATION RESULTS

The dust has not settled from the latest bout of turbulance in world energy markets. OPEC crude oil production currently runs at 17-18 million b/d, down from about 28-30 million b/d during 1973-79. The key question for the 1980s and beyond is when and how fast the demand for OPEC oil will start increasing again. Two conflicting views on this question have recently been expressed. The International Energy Agency (IEA) in its recent World Energy Outlook states that:

> "Energy markets and the oil market in particular are likely to remain deceptively stable through the mid-1980s, but are projected to be increasingly tight there-after. From the mid-1980s onwards, the oil market is likely to gradually move towards a basic disequilibrium again as growing world oil demand will be confronted with stagnating production." 1/

IEA further argues that unless stronger policies are implemented to relieve the demand pressure, such disequilibrium is likely to result in further increases in the price of OPEC oil.

At the other end of the spectrum is the view that OPEC might have set the oil price too high and thus have set in motion some fundamental adjustments which are likely to restrict the demand for OPEC oil to relatively low levels even beyond 1990. This so-called maverick view, shared by several analysts, 2/ holds that the price of OPEC oil could drop substantially below current levels as a result of sustained conservation, fuel substitution, rising non-OPEC production, and slower world economic growth.

1/ International Energy Agency, World Energy Outlook (Paris: OECD, 1982), p. 25.

2/ For example, William Brown at the Hudson Institute and Marian Radetski at the Institute for International Economic Studies, the University of Stockholm. Royal Dutch-Shell also sees the demand for petroleum stagnating until 1990 at well below the 1980 level. Other proponents of this view are Philip Verleger, Jr. at Yale University and S. Fred Singer at the University of Virginia.

One of the main purposes of this section is to sort out the areas of disagreement and to shed some light on this important issue in a systematic manner with the help of WEPM. The chief sources of divergence are concerned with uncertainties in the following areas:

(a) The rate of economic growth and the way economic growth affects the demand for energy.

(b) The degree and the manner in which energy prices affect the demand for final energy and the demand for individual fuels via interfuel substitution.

(c) Non-OPEC energy supply responses--likely supply availabilities of petroleum, natural gas, coal, hydro/nuclear electricity and synthetic fuels.

The following sections will show sensitivities of simulation results with respect to these uncertainties and policy changes. A complete listing of the variables and equations of the model is given in Annex 5.1.

5.1. Simulation of the 1970s

The performance of the WEPM model was tested against historical data of the 1970s. The actual energy prices and supplies are used to simulate the 1970-78 period, but for the 1979-80 period all endogenous variables of the model are simulated. Historical simulation of energy demand for the 1970-78 period starts from actual energy consumption in 1970 and runs year by year, using the simulated demand estimates of the previous year and actual data on GDP, GDP in industrial sector, population, and prices of various energy products paid by final users. Because of the long lag structure present in most of the demand functions, this process requires energy price data prior to 1960, which are not available at this time. As an approximation, it is assumed that all energy prices prior to 1960 remained constant in real terms at their 1960 levels. This is not likely to cause a significant bias in the results. For the capital-surplus oil exporting countries, 50% of the value-added in mining was taken out of industrial sector GDP because otherwise the dominant share of petroleum mining in industrial output distorts the energy/output relationship. Simulation for the 1979-80 period starts from the simulated 1978 demand estimates.

Figure 5.1 presents a summary of historical simulation results. The simulation results for the world primary energy demand (Figure 5.1a) are very close to the actuals, except for the period of the 1973/74 oil price shock. The prediction errors come largely from simulation of industrial country demand, where industrial sector final energy demands are overestimated, transportation demands are underestimated, and the short-term residential energy demands are underestimated. Simulation results for the developing countries as a whole are strikingly close to the actuals (Figure 5.1e - 5.1g).

The overestimation of industrial sector energy consumption of the industrial countries is related to practically zero growth in industrial energy consumption in Western Europe during the 1970-80 period. Even under the assumption of a high price elasticity, this trend implies an unusually low output elasticity of industrial energy demand for the region. In particular, energy consumption per unit of industrial output in the United Kingdom has been declining steadily throughout the 1960s and 1970s, implying an output elasticity substantially lower than those of other industrial countries. This can be taken as an indication of structural changes towards less energy intensive products. It was, however, deliberately assumed that Western Europe is not likely to be much different from other industrial countries in terms of structural characteristics of industrial growth. The semi-autonomous decline in energy intensity can be expected to stabilize once the opportunities for such growth are exhausted.

The apparent underestimation of transportation demand for energy in the 1974-79 period is vindicated by the actuals in 1980 (Figure 5.1f). Gasoline consumption in the United States resumed its steady increases after 1974, as fuel efficiency improvements were delayed and the rise in gasoline prices failed to provide a strong enough incentive to switch to more fuel efficient smaller cars. However, the potential adjustments started to materialize after the 1979-80 oil price increases, closely in agreement with the model predictions.

Interfuel substitution results showed some of the expected short-run over-adjustment problem (see Section 3.1). Figure 5.1b shows that after 1973/74 the simulated world demand for petroleum is lower than the actual,

FIGURE 5.1: DEMAND SIMULATION FOR THE 1970s

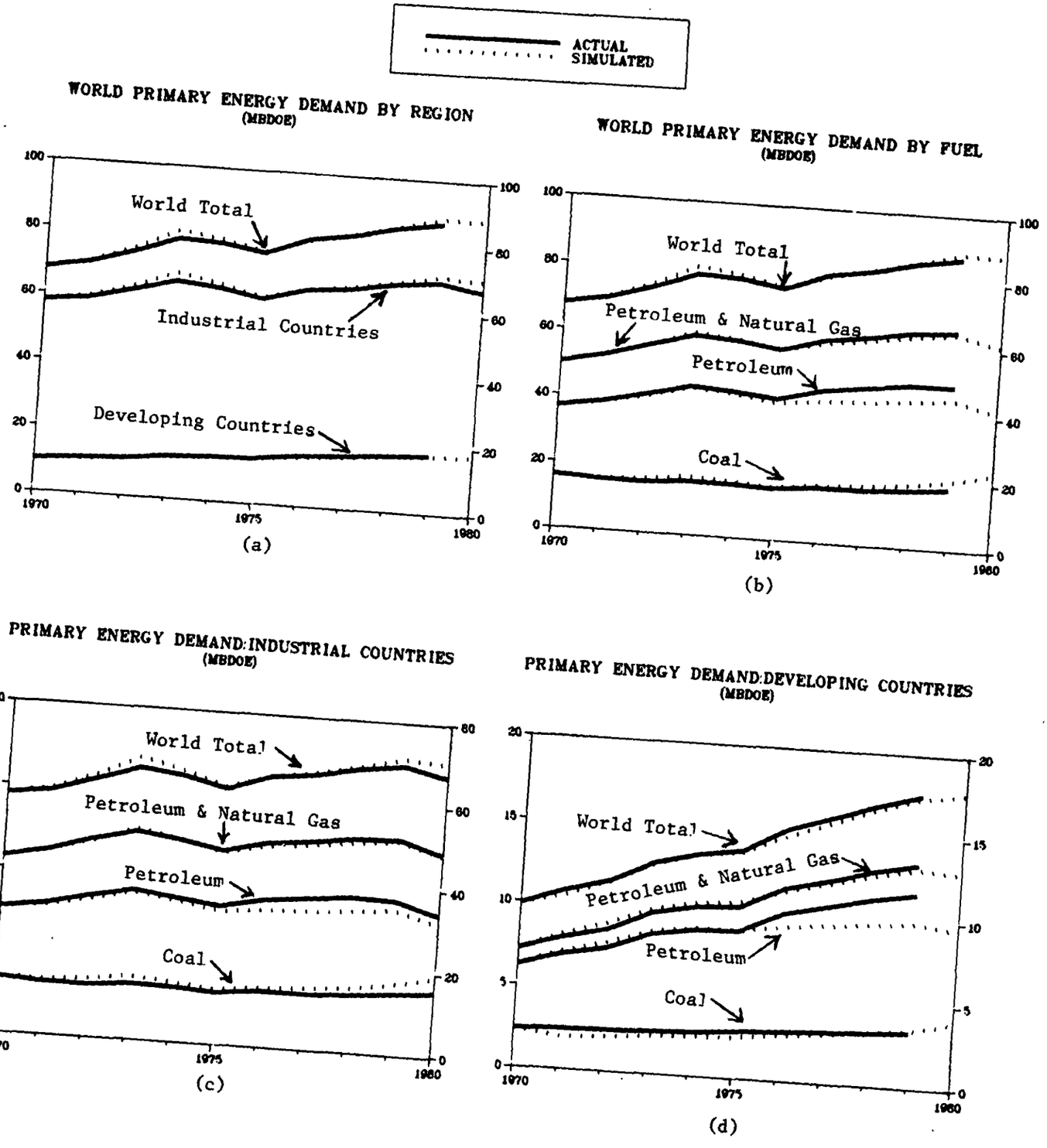
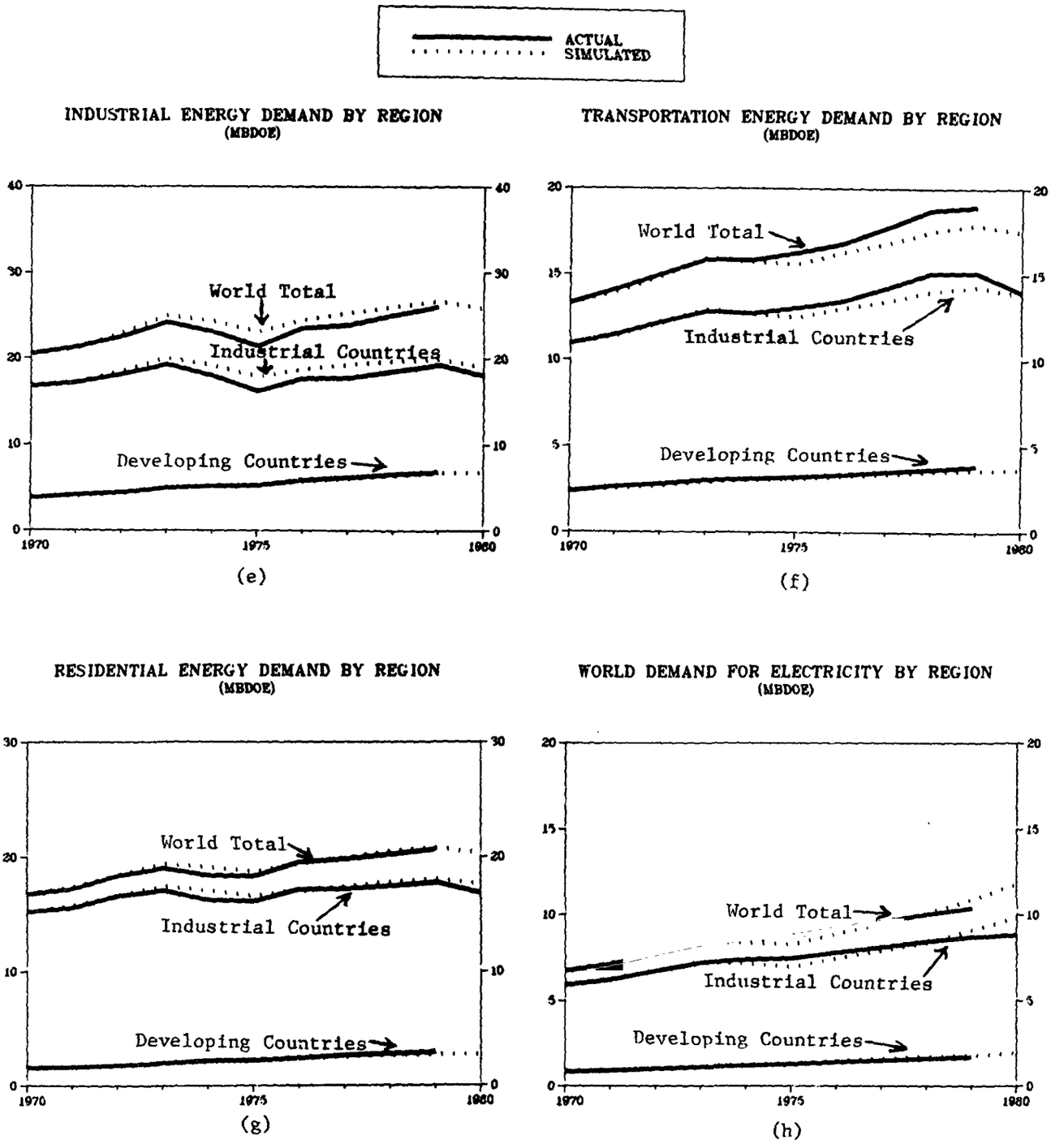


FIGURE 5.1 (continued)



while the simulated demand for coal and natural gas is higher. 1/ Three observations seem important in this connection. First, the model produced reasonably close forecasts of interfuel substitution up to 1973, when relative fuel prices remained stable. Second, the short-run bias dissipates gradually, and the forecasts and actuals converge towards 1979 until another price disturbance again widens the gap (Figure 5.1b-5.1d). Third, the interfuel substitution model is based on the assumption of competitive cost minimization on the part of the end users and supply/demand equilibrium at competitive prices. However, in the case of natural gas and electricity, not all demand at the prevailing prices is met, because these industries are highly regulated and supplies are limited in the short run by the availability of fuel and infrastructure. Actual consumption, therefore, could be persistently lower than desired demand if the prices are regulated at below the competitive levels, creating a situation of disequilibrium.

Prediction errors of interfuel substitution between petroleum and natural gas can in fact be attributed mainly to the assumption of competitive market clearance. The simulation results indicate that the bulk of unsatisfied potential demand for natural gas was met by petroleum. This can be seen by comparing the actual and simulated demands for hydrocarbon fuels (petroleum plus natural gas). The low level of prediction errors for total hydrocarbon fuels and for coal leads to the conclusion that the interfuel substitution model works reasonably well if competitive market clearance indeed prevailed in all fuel markets.

The simulation results for substitution between electricity and other fuels (Figure 5.1h) also show greater substitution in the short run than actuals. This is another manifestation of the short-run over-adjustment problem mentioned in Section 3.1. The errors can be attributed in part to the competitive equilibrium assumption because the electricity market is also heavily regulated. The long-term results for the 1970s as a whole do not show a systematic bias.

1/ The totals for hydrocarbon fuels (petroleum plus natural gas) are shown rather than for petroleum and natural gas separately, in order to avoid congestion in the figures.

The performance tests described above indicate that the model works reasonably well in simulating the historical data of the 1970s. Simulations of total primary energy demands and sectoral final energy demands are reasonably close to the actuals. Simulations of individual fuel demands using the interfuel substitution model posed two problems: (a) overestimation of the short-run interfuel substitution responses: (b) bias due to the assumption of competitive market equilibrium for natural gas and electricity. The anticipated deregulation of the natural gas market in the United States and elsewhere will significantly alleviate this bias for the projection period.

5.2 The Base-Case Projections to the Year 2000

The base-case projections for the period 1978-2000 use the base-case assumptions about energy demand and supply parameters, GDP and population growth, OPEC price of crude oil, non-OPEC supplies of petroleum and natural gas, and supplies of hydro/nuclear electricity and synthetic fuels. The base-case is not intended to be a forecast for the future of energy markets. Its principal aim is to show the likely energy supply and demand relationships under a set of assumptions deemed likely by many. This will serve to bring out the characteristics of the model more clearly.

Assumptions

The base-case assumptions about GDP, GDP per capita and industrial sector GDP are shown in Table 5.1. GDP in the industrial countries is assumed to grow at 2.4% p.a. in the 1980s and at 3.0% p.a. in the 1990s. Compared with those of IEA in its recent World Energy Outlook, the growth rates assumed here for the industrial countries are close to IEA's low growth scenario for the 1980s and to the high growth scenario for the 1990s. GDP growth rates for the oil-exporting developing countries are projected at 3.8% p.a. and 4.8% p.a. for the 1980s and 1990s respectively. The oil-importing developing countries are projected to grow at about the same rate as the oil-exporting developing countries. These growth rates for the industrial and developing countries fall between the low and central growth rate scenarios in recent World Bank projections. 1/

1/ World Bank, World Development Report, 1983, p. 27.

Table 5.1: BASE-CASE GROWTH RATES OF GDP, GDP PER CAPITA AND INDUSTRIAL GDP BY REGIONS
(% per annum)

	GDP		GDP per capita		Industrial Sector GDP	
	1980-1990	1990-2000	1980-1990	1990-2000	1980-1990	1990-2000
NOAM	2.46	3.00	1.80	2.50	2.46	3.00
WEUR	1.91	2.70	1.71	2.45	1.91	2.70
JANZ	3.45	3.60	2.78	3.08	3.45	3.60
CSEX	2.87	5.00	0.22	2.72	3.15	5.50
CDOP	4.24	4.50	1.70	2.32	4.67	4.95
NOEX	4.40	4.90	1.84	2.74	4.83	5.39
OIDC	4.00	4.80	1.81	2.88	4.32	5.18

Source: World Bank, Economic Analysis and Projections Department.

Growth rates of industrial sector GDP have been approximately the same in the long run as total GDP in industrial countries. 1/ The growth rates for industrial sector GDP are assumed to be the same as GDP growth rates for the industrial countries. Industrial sector GDP is assumed to grow 8-10% faster than total GDP for the developing countries, broadly in line with the long-term relationship between the two growth rates.

For the base case, the price of OPEC oil is assumed to decline slightly through the mid-1980s and then increase steadily to reach $37 per barrel (in constant 1981 dollars) in 1990 and $56 in the year 2000. This corresponds closely to the recent price projections to 1995 made by the World Bank. 2/

1/ In the short run, industrial sector GDP tends to fluctuate more than total GDP. This aspect is left to subsequent refinements of the model.

2/ "Price Prospects for Major Primary Commodities," Volume 5 (Energy), Commodities and Export Projections Division, World Bank, July 1982.

The base case also assumes that the taxes on energy products will maintain the same rate structure as in 1978. Also assumed constant are various distribution margins, transportation costs and refinery margins. Most oil-importing countries no longer have price controls on domestic crude oil. The oil-exporting developing countries are assumed to gradually increase their domestic crude oil prices to 30-40% of the export prices by 1990. For the base case, the wellhead price of natural gas is assumed to reach 60-90% of the import price of crude oil in the industrial countries by 1990. This percentage is assumed to be 30-35% for the oil-exporting countries and 55% for the oil-importing developing countries.

World Energy Balance

The base-case projection results are summarized in Tables 5.2-5.3 and presented graphically in Figures 5.2-5.4. The regional and sectoral details are given in Annex 5.2. Under the base-case assumptions, world primary energy demand is projected to decline through the mid-1980s, gradually resume growth in the second half of the 1980s, and then steadily increase in the 1990s. The projected growth rate between 1978 and 1990 is only 0.43% p.a. compared with 2.91% p.a. between 1970 and 1978; for the 1990s, the growth rate is projected at 2.35% p.a. The petroleum price increases that already took place are seen to retard energy consumption growth for most of the 1980s, while further increases in the price of OPEC oil assumed for 1985-2000 are expected to suppress energy demand growth for that period to a level substantially below the growth rate of GDP.

About 43% of the incremental demand for primary energy between 1978 and the year 2000 is expected to come from the oil-importing developing countries, another 27% from the industrial countries, and the remaining 30% from the oil-exporting developing countries (Table 5.2). This result can be traced to the assumption that the developing economies are expected to grow faster and show higher rates of industrial output growth than the industrial countries. In addition, the developing countries are assumed to have higher income elasticity and lower price elasticity of energy demand than the industrial countries, and also price their domestic fuels below the international levels. The growth rate of primary energy consumption in the industrial countries is projected to slow down from 2.1% p.a. during 1970-78

Table 5.2: WORLD ENERGY BALANCE PROJECTIONS TO 2000
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	67.73	78.18	75.50	85.19	86.63	85.44	82.41	81.82	83.86	89.71	99.55	113.13
INDUS.COUNTRIES	57.82	65.45	61.76	68.34	68.87	67.72	64.86	63.87	64.42	65.67	69.59	75.83
CAP-SURP OIL-EXP	0.73	0.94	1.18	1.63	1.57	1.34	1.32	1.38	1.56	2.11	2.74	3.57
OIL-EXP LDCS	2.01	2.51	2.77	3.60	4.17	4.44	4.40	4.58	5.06	6.46	8.04	10.04
OIL-IMP LDCS	7.16	9.28	9.79	11.62	12.03	11.94	11.83	11.98	12.82	15.48	19.19	23.70
PRODUCTION	70.20	80.57	76.72	83.74	86.71	85.56	82.69	82.07	84.52	90.44	100.10	112.75
INDUS.COUNTRIES	40.05	41.78	40.62	42.90	46.22	47.53	46.29	45.60	46.47	47.97	52.02	60.47
CAP-SURP OIL-EXP	17.15	23.58	21.36	23.58	21.11	18.41	16.81	16.49	16.40	16.94	19.50	20.15
OIL-EXP LDCS	8.98	10.85	9.96	11.92	12.38	12.06	11.91	12.21	13.09	15.29	17.34	18.96
OIL-IMP LDCS	4.02	4.36	4.78	5.34	7.00	7.57	7.67	7.77	8.56	10.23	11.24	13.18
NET IMPORTS	1.85	1.86	2.39	3.85	2.27	2.20	2.03	2.05	1.68	1.48	1.40	1.48
INDUS.COUNTRIES	20.71	26.42	23.48	26.36	23.95	21.51	19.88	19.59	19.30	18.84	18.38	15.24
CAP-SURP OIL-EXP	-15.97	-22.09	-19.70	-21.53	-19.17	-16.72	-15.15	-14.75	-14.47	-14.40	-16.28	-16.04
OIL-EXP LDCS	-6.76	-8.20	-7.04	-8.08	-8.12	-7.52	-7.41	-7.53	-7.93	-8.72	-9.18	-8.78
OIL-IMP LDCS	3.86	5.72	5.65	7.10	5.62	4.93	4.71	4.75	4.78	5.77	8.48	11.06
BUNKERS	2.04	2.68	2.22	2.31	2.36	2.35	2.35	2.37	2.44	2.63	2.83	3.05
CPE NET IMPORTS	-1.32	-1.37	-1.86	-2.34	-2.15	-2.08	-2.01	-1.95	-1.85	-1.70	-1.63	-1.70

Table 5.3: WORLD ENERGY BALANCE PROJECTIONS TO 2000
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	67.73	78.18	75.50	85.19	86.63	85.44	82.41	81.82	83.86	89.71	99.55	113.13
LIQ FUELS	36.70	44.50	42.37	48.79	45.92	42.89	41.20	41.15	41.88	43.76	48.20	51.72
SYNCRUD	0	0	0	0.08	0.10	0.11	0.12	0.13	0.15	0.68	1.38	2.80
COLIQD	0	0	0	0.01	0.01	0.03	0.04	0.06	0.10	0.43	0.88	1.95
NAT. GAS	13.22	15.39	14.87	15.84	15.85	15.72	15.04	15.00	15.04	15.07	16.48	17.60
COAL	16.00	16.07	15.51	17.22	21.28	23.12	22.33	21.68	22.63	24.84	27.52	34.58
SCOAL	13.27	13.24	12.80	14.55	18.57	20.29	19.37	18.60	19.31	20.44	21.66	26.06
METCOAL	2.72	2.83	2.70	2.65	2.70	2.79	2.88	2.97	3.15	3.69	4.39	5.27
PRIM.ELEC.	1.81	2.22	2.75	3.34	3.58	3.71	3.85	3.99	4.31	6.04	7.34	9.23
PRODUCTION	70.20	80.57	76.72	83.74	86.71	85.56	82.69	82.07	84.52	90.44	100.10	112.75
PETROLEUM	39.24	47.47	43.14	48.20	46.77	43.79	42.16	42.18	43.07	44.59	48.32	49.73
SYNCRUD	0	0	0	0.08	0.10	0.11	0.12	0.13	0.15	0.68	1.38	2.80
NAT.GAS	13.58	15.92	15.13	15.77	15.73	15.59	14.91	14.87	14.89	14.87	16.20	17.20
COAL	15.56	14.95	15.70	16.34	20.53	22.36	21.65	20.90	22.09	24.27	26.86	33.80
PRIM.ELEC.	1.81	2.22	2.75	3.34	3.58	3.71	3.85	3.99	4.31	6.04	7.34	9.23
OF.WH.NUC	0.09	0.28	0.58	0.96	1.06	1.10	1.14	1.19	1.30	2.48	3.53	5.14
BUNKERS	2.04	2.68	2.22	2.31	2.36	2.35	2.35	2.37	2.44	2.63	2.83	3.05
CPE.PETRO	0.92	1.01	1.29	1.61	1.40	1.31	1.22	1.14	1.00	0.70	0.46	0.30
CPE.NAT.GAS	-0.01	-0.12	0.03	0.11	0.12	0.13	0.13	0.14	0.15	0.20	0.28	0.40
CPE.COAL	0.42	0.48	0.54	0.62	0.63	0.64	0.66	0.67	0.70	0.80	0.89	1.00

FIGURE 5.2

WORLD PRIMARY ENERGY DEMAND BY REGION
(MBDOE)

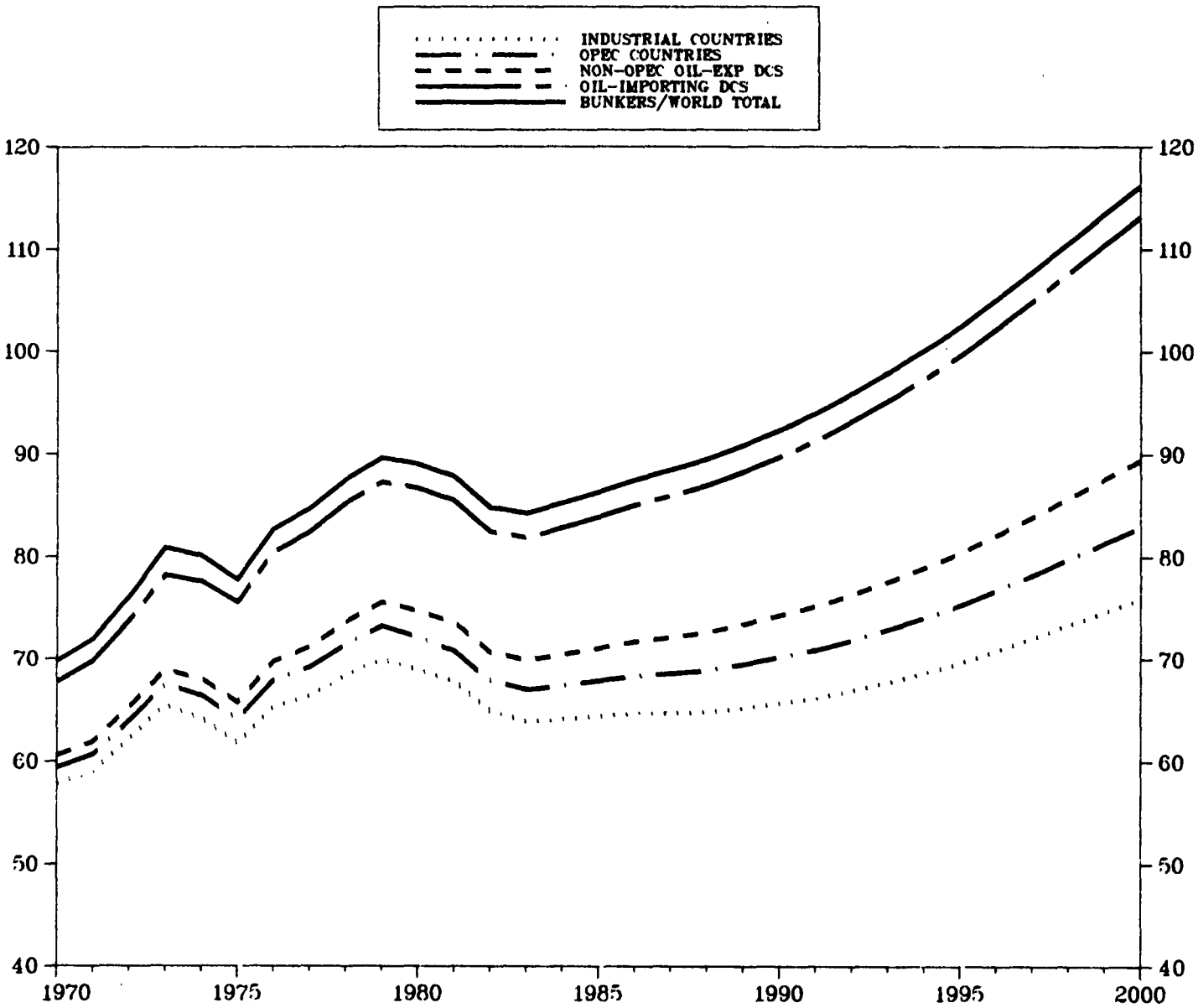


FIGURE 5.3

WORLD PRIMARY ENERGY DEMAND BY FUEL
(MBDOE)

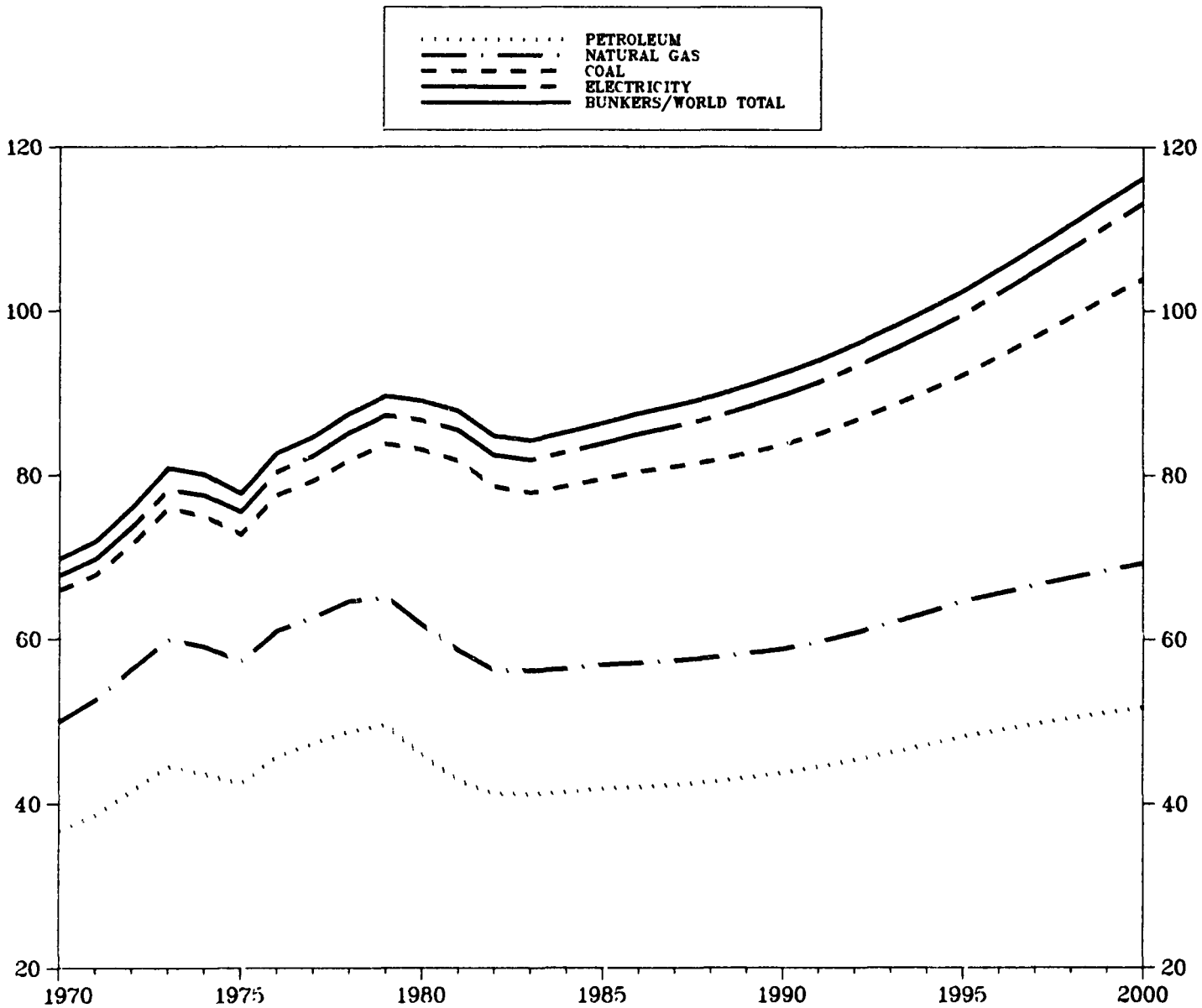
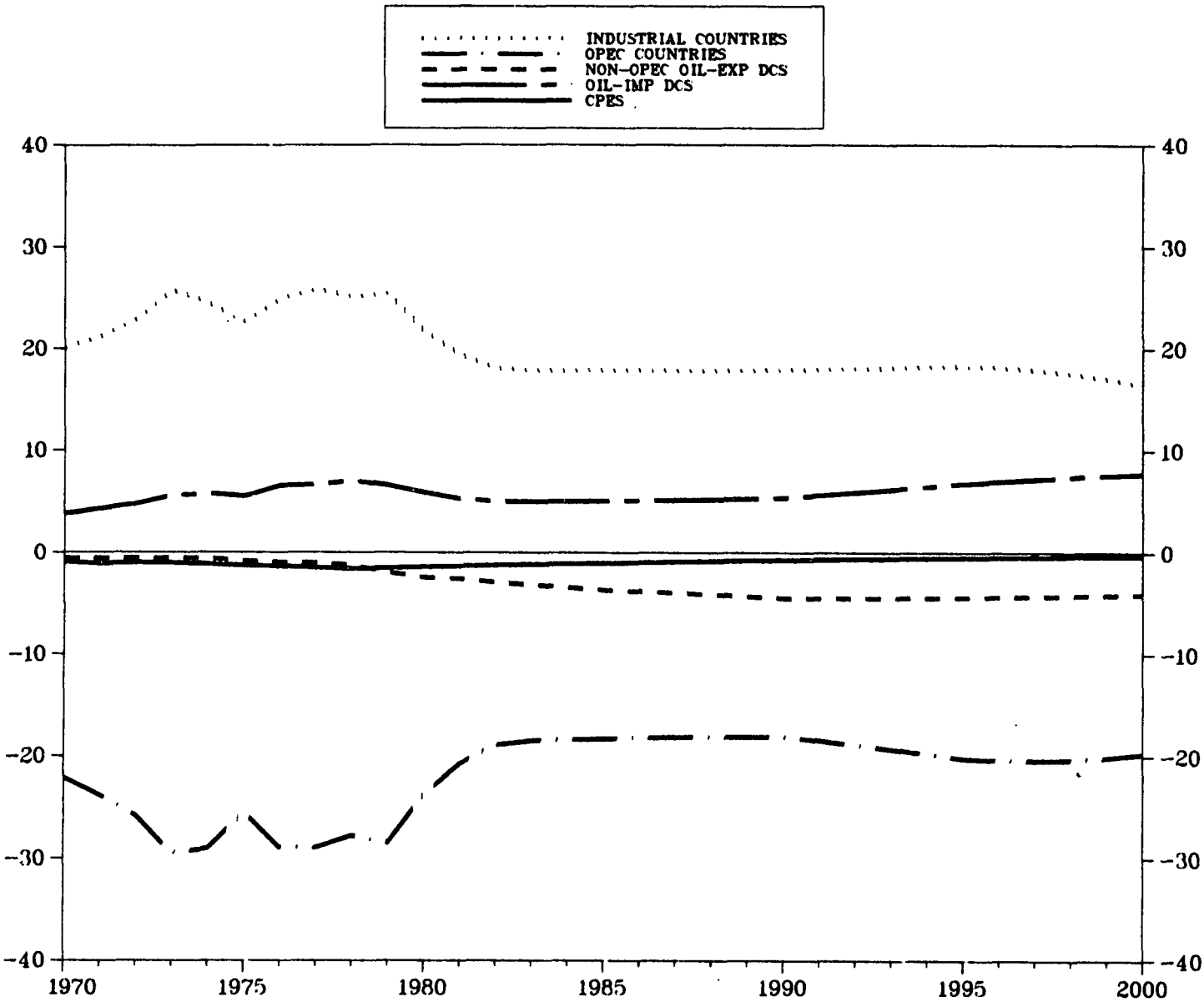


FIGURE 5.4

NET IMPORTS AND EXPORTS OF PETROLEUM BY REGION
(MBDOE)



to 0.5% p.a. during 1978-2000, and from 6.9% to 3.7% for the developing countries for the same periods.

The base-case results suggest that world petroleum demand is likely to remain more or less flat at the projected 1982 level until the mid-1980s. 1/ OPEC crude oil production is expected to hover around 21 million b/d, with net exports of petroleum at around 18-19 million b/d (Figure 5.4), which is well below the productive capacity of OPEC. World petroleum demand is projected to increase slowly in the second half of the 1980s, but the growth rate accelerates in the 1990s, reaching its 1978 level by 1995. The demand for OPEC oil, however, is projected to remain only at around 25 million b/d during the second half of the 1990s, partly because of the projected increases in conventional petroleum supplies in non-OPEC developing countries.

Of the total incremental demand for primary energy between 1978 and 2000, liquid fuels are expected to supply 10.5%, natural gas 6.3%, coal 62% and primary electricity 21.2% (Table 5.3). Interfuel substitution is seen to take place primarily from hydrocarbon fuels to coal both directly and indirectly through thermal electricity generation. The share of coal in total primary energy consumption is seen to increase from 20.2% in 1978 to 27.7% in 1990, and 30.6% in the year 2000. This result has to be looked at in connection with the price differential between coal and petroleum, which greatly widened in the recent past and is assumed to continue to widen throughout the projection period.

1/ The model results up to 1982 are reasonably close to the actuals. For example, OPEC production of crude oil is projected to decline from 30.4 million b/d in 1978 to 26.5 million b/d in 1980, 23.3 million b/d in 1981 and 21.3 million b/d in 1982, compared with the actuals of 26.9 million b/d in 1980, 22.7 million b/d in 1981, and an estimated year average of 19 million b/d for 1982. A part of the discrepancy between the simulated and actual figures for OPEC production is explained by stock accumulation in 1980 and the first half of 1981, and subsequent stock drawdown in 1982, which the model is not equipped to deal with. The projected 1980 OPEC production would be very close to the actual without stock accumulation. Without stock drawdown, the actual OPEC production is estimated at around 20-20.5 million b/d. Even after adjustments for the stock behavior, the model tends to slightly overestimate the demands for total primary energy and petroleum when tested against the actual data of the recent past. But, overall, the prediction errors are reasonably small.

Of the total incremental demand for thermal coal between 1978 and 2000, about 53.4% is expected to come from the thermal power sector, 22.7% from the synthetic fuel industry, and 23.9% from the industrial sector. The bulk of substitution from hydrocarbon fuels to coal, in other words, is expected to take place indirectly through conversions to electricity and synthetic fuels.

Overall, world demand for energy and petroleum is likely to remain at relatively low levels throughout the 1980s and for most of the 1990s if OPEC follows the base-case pricing path for its crude oil. The past and expected price increases of petroleum provide a strong and substained incentive to substitute away from energy and petroleum, and keep demand for OPEC oil within comfortable margins of OPEC productive capacity for the next 10 years or so. Playing a key role in this will be the availability of coal as a substitute fuel.

Sectoral Demands and Interfuel Substitution

Table 5.4 examines in detail the base-case projections of sectoral final energy demands. The focus here is on the efficiency changes of final energy consumption in response to energy price increases.

Demand for transportation fuels in the industrial countries is projected to remain well below its 1978 level through 1985, to recover slightly above the 1978 level by 1990, and increase at 1.7% p.a. in the 1990s, compared to a 4.1% p.a. growth during 1970-78. In the developing countries, on the other hand, transportation energy demands are projected to increase at 2.2% p.a. during 1978-90 and 4.0% p.a. during the 1990s, compared with 5.7% p.a. growth during 1970-78.

Passenger car ownership per capita in industrial countries is projected to increase by only 27% between 1978 and the year 2000, the bulk of the increases coming in Japan and Western Europe where the saturation effect is still less severe than in North America. In the developing countries, per capita passenger car ownership is expected to increase by 73% between 1978 and the year 2000. In terms of transportation fuel consumption per capita, the growth rate for the developing countries is twice that of the industrial countries. Gasoline consumption per car is expected to drop by 20% in the industrial countries between 1978 and the year 2000, largely through

Table 5.4: EFFICIENCIES OF FINAL ENERGY CONSUMPTION--
HISTORICAL (1970-78) AND PROJECTED (1978-2000)

	Transport Sector				Industrial Sector		Residential Sector		
	Passenger Cars per 100 People	Gasoline Consumption Per Car (Gallons) (Per Day)	Transport Fuel Consumption Per Capita (BOE/Year)	Gasoline Price Index (1978=100)	Energy Intensity of Output (BOE per) (1000$ GDP) /a	Industrial Energy Price Index (1978=100)	Energy Intensity of GDP (BOE per) (1000$ GDP) /a	Per Capita Consumption (BOE)	Residential Energy Price Index (1978=100)
Industrial Countries									
1970	27.1	1.84	6.37	89.9	4.73	58.2	1.47	8.84	71.6
1978	37.2	1.79	8.29	100.0	4.14	100.0	1.28	9.56	100.0
1985	38.2	1.58	7.63	165.9	3.12	144.0	1.03	8.48	140.4
1990	41.5	1.53	8.13	188.6	2.61	156.2	0.90	8.49	158.2
2000	47.1	1.44	9.22	268.5	2.18	195.2	0.74	8.94	202.8
Developing Countries									
1970	1.00	3.19	0.48	61.9	5.02	76.0	0.57	0.31	112.4
1978	1.88	2.00	0.61	100.0	5.31	100.0	0.66	0.46	100.0
1985	1.97	1.71	0.56	159.1	5.08	123.5	0.59	0.44	156.0
1990	2.33	1.52	0.60	193.1	4.93	139.6	0.56	0.47	188.5
2000	3.25	1.28	0.74	278.1	4.75	182.5	0.49	0.54	259.8

/a In 1977 constant dollars.

Source: Economic Analysis and Projections Department, World Bank.

improvements in fuel efficiency. Rapid increases in per capita car ownership in the developing countries are expected to reduce substantially the utilization rate of passenger cars, contributing to a decline in gasoline consumption per car.

Per capita consumption of transportation fuels is expected to increase by only 11% in the industrial countries between 1978 and 2000, and by 21% in the developing countries for the same period. The rate of increase of per capita consumption of transportation services--increases of passenger-miles and freight miles--would be substantially higher than that of per capita consumption of transportation fuels because of improvements in fuel efficiency.

Final energy demand of the industrial sector is projected to remain below the 1978 level during the 1980s and 1990s in North America and Western Europe, increase only slightly during the latter part of the 1990s in Japan/Australia/New Zealand, but more than double between 1978 and 2000 in the developing countries. Energy consumption per unit of industrial GDP in the industrial countries stayed more or less constant before the 1973/74 petroleum price shock, but declined by 12.5% between 1973 and 1978. It is projected to decline further by 47% between 1978 and 2000. On the other hand, the energy intensity of industrial production in the developing countries increased by 5.8% between 1970 and 1978, and is projected to decline by only 10.5% between 1978 and 2000. The basis for this divergent trend is the anticipated expansion of relatively energy intensive industries in the developing countries, partly offsetting gains in energy efficiency.

The residential sector final energy demand of the industrial countries does not decline as rapidly as in the industrial sector during the 1978-85 period and recovers somewhat faster during 1985-2000. In the developing countries, residential energy demand increases at a somewhat slower rate (2.9% p.a. during 1978-2000) than energy demand in the industrial sector, largely as a result of the assumption that industrial sector GDP grows faster than total GDP in developing countries.

Residential energy consumption per unit of GDP declined by 13% between 1970 and 1978 in the industrial countries, and is projected to decline by another 42% between 1978 and the year 2000. In the developing countries,

residential energy intensity increased by 16% during 1970-78, but is projected to decline by 26% during 1978-2000. In terms of per capita residential energy consumption, the projections imply only slight reductions for the industrial countries and sizeable increases for the developing countries between 1978 and 2000.

Table 5.5 shows the interfuel substitution results by sectors. The industrial sector of the industrial countries is seen to substitute coal and electricity for petroleum and natural gas. The share of coal in the industrial sector final energy consumption is seen to increase to almost 28%,

Table 5.5: SECTORAL FUEL SHARES: HISTORICAL (1970-78) AND PROJECTED (1978-2000) (percent)

	Industrial Countries					Developing Countries				
	1970	1978	1985	1990	2000	1970	1978	1985	1990	2000
Industrial Sector /a										
Petroleum	41.3	44.8	39.6	38.0	34.0	51.8	57.5	48.4	47.1	43.9
Natural Gas	24.7	21.8	19.3	18.5	17.6	16.8	15.8	19.8	18.5	18.2
Coal	20.2	17.6	22.3	24.1	27.8	21.6	15.8	20.9	23.5	28.2
Electricity	13.8	15.8	18.8	19.4	20.6	9.8	10.9	10.9	10.9	9.7
Residential Sector										
Petroleum	46.5	41.6	30.9	28.4	23.4	62.2	57.1	44.1	41.0	36.0
Natural Gas	28.5	32.2	36.1	35.8	35.8	4.4	6.4	13.9	15.0	18.1
Coal	9.5	4.2	3.0	2.1	1.1	15.1	17.1	15.2	12.9	9.3
Electricity	15.4	22.0	30.0	33.8	39.7	18.3	19.4	26.7	31.1	36.6
Thermal Power Sector										
Petroleum	24.3	28.5	16.0	11.0	4.7	54.4	56.0	38.2	38.0	40.1
Natural Gas	18.3	15.3	11.4	9.6	6.8	5.6	8.8	8.8	9.8	10.8
Coal	57.4	56.3	72.6	79.4	88.5	40.0	35.2	53.1	52.2	49.1

/a Including metallurgical coal for iron and steel industry.

Source: Economic Analysis and Projections Department, World Bank.

and the share of electricity to 21% by the year 2000. The percentage share of natural gas declines as much as that of petroleum during 1978-2000. Gradual decontrol of natural gas prices in North America and expiration of long-term contracts in Western Europe are likely to bring down substantially the market share of natural gas in those regions, while in Japan and Australia, where such problems are not present, the share is expected to increase considerably above the current low level. In terms of absolute quantities, the total replacement of petroleum and natural gas by coal and electricity is not as large as what the changes in shares may suggest; at the 1978 market shares of petroleum and natural gas, the total demand for hydrocarbon fuels would be 3 million b/d higher than the projected level for the year 2000, or 15% of the total industrial energy demand of the industrial countries in that year.

In the oil-exporting developing countries, the shares of petroleum and natural gas in industrial energy consumption are projected to roughly maintain their 1978 levels through the year 2000. Coal is seen to make some inroads in oil-exporting developing countries where coal is available (e.g., Indonesia, Nigeria, Venezuela and Mexico), but its contribution in absolute quantities is not likely to be significant. If these countries decide to encourage consumption of natural gas by pricing natural gas at lower levels than assumed in the base-case decontrol scenario, the share of natural gas could be much higher than the projected levels for the base case.

The oil-importing developing countries are projected to reduce the petroleum share of industrial energy consumption from 56.5% in 1978 to 45.7% by the year 2000, while the shares of natural gas and coal are seen to increase from 5.6% to 11.4% and from 23.3% to 40.0%, respectively, during the period. Rapid increases in demand for both thermal and metallurgical coals in the oil-importing developing countries are expected to push up the share of coal in the industrial sector energy consumption. Natural gas also is likely to play a greater role in the oil-importing developing countries as these countries find and develop more domestically available natural gas resources.

Electricity and natural gas are the main substitutes for petroleum in the residential sector of industrial countries. The share of electricity is projected to increase from 22% in 1978 to 39.7% in the year 2000 in the industrial countries, while the share of natural gas is seen to increase from

32.2% to 35.8%. The residential price of natural gas increases faster than that of electricity but slower than that of petroleum, making natural gas less competitive than electricity but more competitive than petroleum. This is not the case in the developing countries where natural gas is available: the residential market share of natural gas is expected to quadruple by the year 2000, while that of electricity is likely to double.

Demand for electricity is projected to increase at 2.1% p.a. in the industrial countries between 1978 and the year 2000, compared with 4.5% p.a. growth during the 1970-78 period. Electricity demand in the developing countries grew at 8.5% p.a. during 1970-78, but is projected to increase only at 4.8% p.a. between 1978 and the year 2000. These are much faster growth rates than that of total primary energy demand, reflecting the interfuel substitution adjustments in favor of electricity.

The demand for thermal coal for power generation is expected to increase rapidly. Coal is expected to become the dominant fuel for thermal power generation (close to 88% of the market by the year 2000 in the industrial and oil-importing developing countries), while petroleum and natural gas are expected to decline almost to the point of insignificance. In the oil-exporting developing countries, however, petroleum and natural gas will continue to be the main source of thermal electricity, with coal making only a minor contribution in the 1990s.

International Trade and Export Prices

It is interesting to note that international trade in natural gas does not emerge as a strong substitute for petroleum trade. The net import demand for natural gas in North America is nil for most of the projection period. Japan and Australia as a group does not emerge as a major net importer of natural gas. This is partly because of LNG exports from Australia. But, more importantly, it appears to be uneconomical for Japan to expand LNG imports although it has been doing so for environmental reasons. In Western Europe, natural gas imports are projected to increase only in the late 1990s, largely to make up for the depleting supplies from Netherlands and North Sea. The prospect for international trade in natural gas hinges on the pricing policies adopted by the natural gas exporters. Insistence on a fixed parity with the price of petroleum, as assumed in the base case, is seen to hamper the potential growth of natural gas trade.

International trade in coal on the other hand is expected to increase rapidly. Western Europe, Japan and several oil-importing developing countries are expected to become major importers of coal from North America, Australia, South Africa, and several other countries. Net coal exports from North America, which reached 1.3 million b/d of oil equivalents (98 million tons of hard coal equivalents) in 1981, is projected to approximately double by 1990, and increase even faster in the 1990s to reach 8.6 million b/d (650 million tons of hard coal equivalent) by the year 2000. Western Europe is projected to increase net coal imports from 1.2 million b/d (88 million tons) in 1980 to 5.4 million b/d (400 million tons) by the year 2000, while increasing exports from Australia are seen to be more than sufficient to compensate for increasing import demands from Japan. The oil-importing developing countries are also expected to increase coal imports rapidly to 3.2 million b/d (236 million tons) of net imports from the rest of the world by the year 2000.

These projections for coal demand and trade depend critically on the base-case assumption about the OPEC petroleum price and the price differential between petroleum products and coal. Figure 5.5 illustrates the base-case relationship between petroleum and coal prices in international markets. With coal prices increasing only mildly along the long-term coal supply curve, the OPEC pricing path assumed for the base case implies a widening price differential between the two fuels. This accelerates the substitution of coal for petroleum, as projected in the base case.

5.3 Simulations under Alternative Scenarios

High Economic Growth Scenario

The most critical uncertainty facing the energy markets is economic growth. The base-case economic growth rates reflect a fairly pessimistic assessment of global economic growth prospects in the wake of the 1979-80 petroleum price shock and global recession. It is, therefore, not difficult to envisage a more optimistic long-term outlook for economic growth than the base case, once the world economy recovers from the recession. The high economic growth scenario postulates 20% higher economic growth rates than the base case for the 1985-2000 period for all regions, keeping intact all other base-case assumptions.

FIGURE 5.5

INTERNATIONAL EXPORT PRICES OF FUELS
(1981$/BOE)

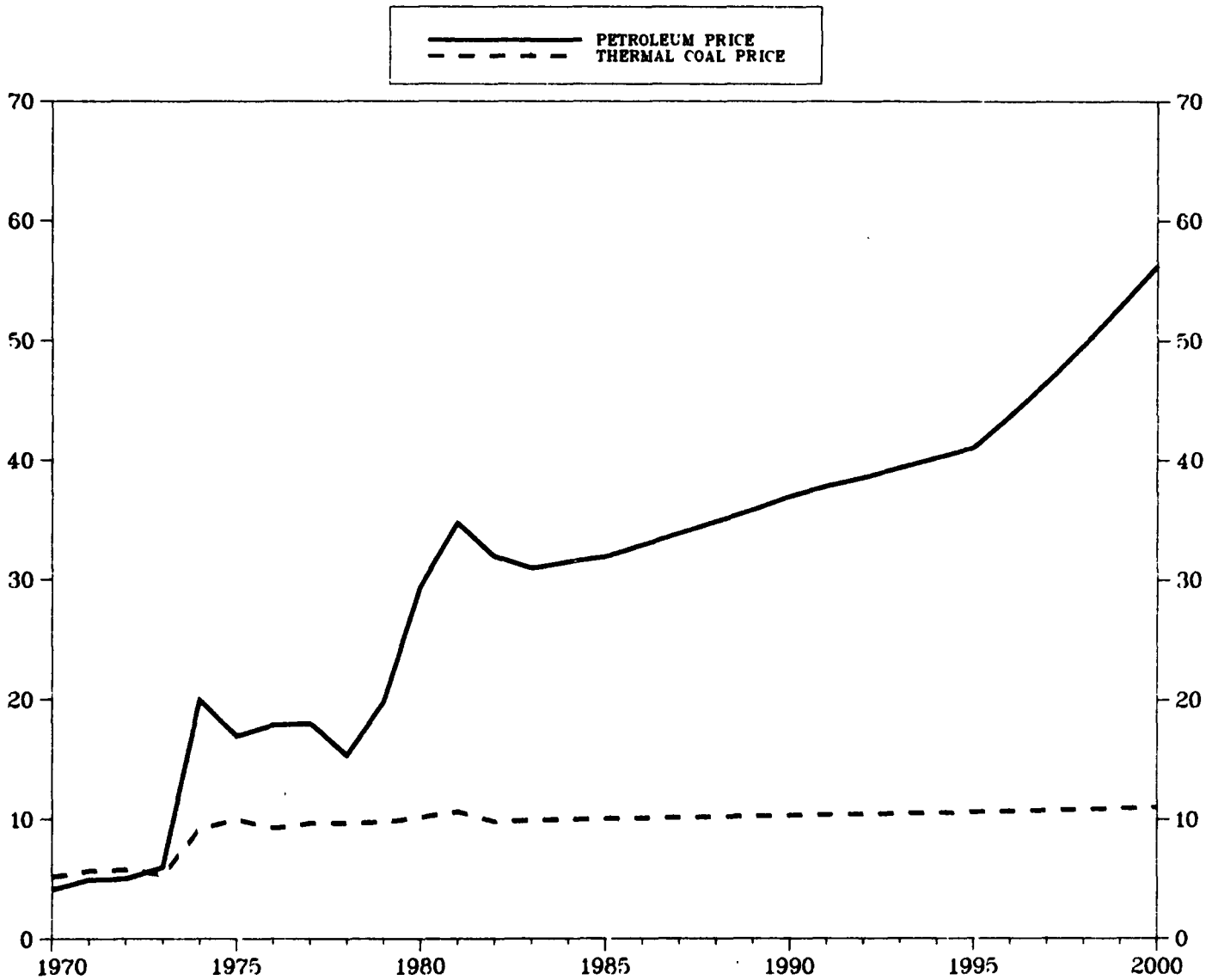


Table 5.6 shows that the GDP elasticity of world primary energy demand is slightly greater than unity, because of rapid industrialization and higher-than-unitary income elasticity of energy demand in the developing countries. Given a set of relative fuel prices, higher economic growth calls for approximately proportional increases in all primary fossil fuels. For the developing countries as a whole the increase in the demand for petroleum is slightly more than proportional. This is because a change in economic growth rate changes the relative importance of the developing country regions and the final consumption sectors.

High economic growth drastically improves the outlook for OPEC production and exports. World demand for OPEC petroleum increases by 2.6 times the percentage increase in world GDP by the year 2000, reflecting OPEC's position as the residual supplier to the world market. This immediately suggests the strong dependence of OPEC interests on world economic growth, a subject that will be discussed in the next section.

Low Demand Adjustment Scenario

The evidence on the long-term price elasticities of final energy demands is by no means definitive. The low demand adjustment scenario, which assumes final energy demand elasticities 20% less than the base case, is approximately equivalent to the mid-point between the time-series estimates and the international cross-sectional, time-series estimates.

A sensitivity analysis of the dynamic path of demand adjustments and interfuel substitution elasticities has not been made. The lag structure of demand adjustments will not affect the long-term results. It is difficult to define and estimate sensitivities to different interfuel substitution elasticities, because they are interrelated and the empirical basis for changing them one way or another is weak. These areas are left for further investigation.

Table 5.7 summarizes the sentivity results. A 20% reduction in the price elasticities results in about a 10% increase in world primary energy demand and a 7.5% increase in world petroleum demand by the year 2000. Because the price elasticities assumed for the transportation sector are lower than those of the industrial and residential sectors, a 20% across-the-board reduction has less impact on the demand for transportation fuels

Table 5.6: HIGH ECONOMIC GROWTH SCENARIO

(MBDOE unless otherwise noted)

	1985	1990	1995	2000
World GDP	(0.67)	(4.24)	(7.89)	(11.74)
Industrial Countries	(0.59)	(3.71)	(6.78)	(9.96)
Developing Countries	(0.88)	(5.71)	(10.64)	(15.81)
World Primary Energy Demand	84.5	93.9	108.3	128.2
	(0.7)	(4.6)	(8.8)	(13.3)
Industrial Countries	64.8	68.1	74.3	83.3
	(0.6)	(3.7)	(6.8)	(9.9)
Developing Countries	19.7	25.8	34.0	44.9
	(1.3)	(7.5)	(13.3)	(20.4)
World Petroleum Demand	42.2	46.0	52.7	59.1
	(0.8)	(5.0)	(9.4)	(14.2)
Industrial Countries	30.7	31.3	33.6	34.7
	(0.6)	(3.7)	(6.7)	(9.8)
Developing Countries	11.5	14.7	19.1	24.4
	(1.8)	(8.1)	(13.7)	(21.4)
OPEC Production & Exports				
Production	22.4	23.8	29.0	32.1
	(6.2)	(10.7)	(18.9)	(30.5)
Exports	18.6	20.0	24.2	26.1
	(1.6)	(10.5)	(19.8)	(31.8)

Note: Figures in parentheses show the percent differences from the base case.

Source: World Bank, Economic Analysis & Projections Department.

(consisting mostly of petroleum products) than on other final energy demands. Because of higher price elasticities assumed for the industrial countries than for the developing countries, it is obvious that the industrial countries will

Table 5.7: LOW DEMAND ADJUSTMENT SCENARIO

(MBDOE)

	1985	1990	1995	2000
World Primary Energy Demand	87.3 (4.1)	95.4 (6.4)	107.6 (8.1)	124.3 (9.9)
Industrial Countries	67.4 (4.6)	70.5 (7.4)	76.1 (9.3)	84.5 (11.5)
Developing Countries	19.9 (2.4)	24.9 (3.6)	31.5 (5.1)	39.8 (6.7)
World Petroleum Demand	43.3 (3.3)	45.9 (4.8)	51.2 (6.2)	55.6 (7.5)
Industrial Countries	31.7 (3.8)	32.0 (6.2)	33.8 (7.5)	34.5 (9.2)
Developing Countries	11.6 (2.3)	13.9 (2.1)	17.4 (3.8)	21.2 (5.3)
OPEC Petroleum Production	22.5 (6.6)	23.7 (10.2)	27.3 (11.9)	28.5 (15.8)
OPEC Petroleum Exports	19.7 (7.7)	20.3 (12.2)	23.2 (14.9)	23.5 (18.7)

Note: Figures in parentheses show the percent differences from the base case.

Source: World Bank, Economic Analysis & Projections Department.

account for most of the increases in demands for energy and petroleum if the price elasticities were lower.

A 20% reduction in price elasticity results in an almost 19% increase in OPEC exports of petroleum by the year 2000. It should, however, be noted that this is the sensitivity of OPEC exports to final energy demand elasticities; if the interfuel substitution elasticities were also lower than the base case, the demand for OPEC oil would have increased by more than 19%.

Low Nuclear Power Scenario

Given the possibility that the base-case supply projections for nuclear power probably represent an optimistic view, it is important to know the implications of a significant shortfall in nuclear power supplies. The low nuclear scenario assumes nuclear power supplies which are 20% lower than the base case for the year 2000, with linear interpolation for the intervening years.

The low nuclear power scenario is equivalent to a loss of about one million bdoe in the form of electricity for the year 2000. It requires about 3.1 million bdoe of fossil fuels to make up for this loss through thermal power generation. The main difference under this scenario is an increase in world primary fossil fuel consumption by 3.1 million bdoe, while other variables are little affected.

The bulk (88%) of the increased demand for fossil fuels is met by thermal coal, with only small contributions from petroleum (7%) and natural gas (5%). Not surprisingly, these fuel shares are virtually the same as the base-case fuel shares in thermal power generation for the year 2000. Thus, the main consequence of a shortfall in nuclear power supplies is an increase in coal-fired thermal power generation.

Tariff Scenario

Softening of the international petroleum prices in recent years has raised the possibility of a tariff on imports of petroleum on the part of the oil-importing countries. Such an action is likely to induce a counteraction by OPEC, and the end result would be difficult to predict. However, the model can be used to calculate the first-round results of such a tariff. The scenario here assumes a 30% tariff on petroleum imports for the 1983-2000 period, with all other base-case conditions unchanged.

Table 5.8 summarizes the results of such a tariff. It is shown that the tariff would result in a substantial decline in the world demand for petroleum but only minor reductions in total primary energy demand. The world demand for coal increases more than that for natural gas in the short run because the price of natural gas is assumed to increase in line with petroleum prices. After adjustments to the change in relative fuel prices are completed, the demand for natural gas increases more than that for coal, because petroleum is more substitutable for natural gas than for coal.

Table 5.8: IMPACT OF A TARIFF ON PETROLEUM IMPORTS
(Percentage changes from the base case)

	1985	1990	1995	2000
World Primary Energy Demand	-0.5	-1.7	-2.1	-2.1
World Petroleum Demand	-6.0	-8.4	-9.3	-8.9
World Natural Gas Demand	4.4	7.0	8.0	7.8
World Coal Demand	6.3	4.2	3.8	2.4
OPEC Petroleum Production	-11.8	-16.8	-18.5	-18.6
OPEC Petroleum Exports	-13.7	-19.8	-21.4	-22.9

Source: World Bank, Economic Analysis & Projections Department.

Such a tariff could have a major negative impact on OPEC production and exports of petroleum. The non-OPEC demand for OPEC petroleum drops by about 23% by the year 2000. If the oil-importing countries raise at the same time the price of domestic petroleum to the cost of imported crude oil including the tariff, OPEC exports will suffer a greater reduction than the estimate shown above.

Comparison with Other Projections

The projections recently published in the World Energy Outlook by the International Energy Agency (IEA) provide a useful comparison for the simulation results described above. IEA's high demand scenario assumes a constant real price of OPEC oil at $29 per barrel (in 1981 dollars) for the 1985-2000 period, while its low demand scenario assumes 3% real increases annually during 1985-2000 to reach $45 per barrel (in 1981 dollars) by the year 2000. Our base-case economic growth rates for the industrial countries are close to IEA's low growth scenario for 1980-90 and to the high growth scenario for 1990-2000. The base-case economic growth rates for the oil-exporting developing countries are on the low side of IEA's range, and on the high side for the oil-importing developing countries.

The WEPM base-case supply projections for petroleum including synthetic liquid fuels are broadly comparable with the IEA projections (see

Table 5.9). The base-case supply projections for petroleum tend to be optimistic compared with IEA's assessment towards the year 2000, the difference being the petroleum supply projections for non-OPEC developing countries. IEA's natural gas supply projections for the non-OPEC market economy countries range from 14.4 to 17.5 million b/d for 1990 and between 13.6 and 21.6 million b/d for 2000. Our natural gas supply figures fall at the median of IEA's ranges. The WEPM assumptions about nuclear electricity supplies are slightly lower than those of IEA.

To provide a set of projections roughly comparable with IEA's high demand scenario, WEPM was run under the assumption that the real price of OPEC crude oil will remain constant at its 1982 level for the 1983-2000 period, while keeping all other base-case assumptions. The WEPM base case is taken to be roughly comparable with IEA's low demand scenario. Table 5.9 provides a comparison of WEPM and IEA projections. The lower bound of WEPM projections in Table 5.9 is the WEPM base case and the upper bound is the WEPM constant price case. IEA's low demand and high demand scenarios provide the lower and upper bounds of IEA projections.

It is clear that IEA foresees a lower degree of energy demand adjustments to energy prices than assumed in WEPM. 1/ IEA's world primary energy demand projections are substantially higher than those of WEPM. The dynamic structure of energy demand adjustments implicit in IEA projections is peculiar in that a sudden deceleration of demand growth occurs towards the year 2000.

In terms of world petroleum demand, the WEPM results are generally lower than the IEA projections, but the difference is not as great as the

---

1/ This is indeed the case. IEA uses long-term price elasticities in the range of -0.35~ -0.45 for the industrial sector and -0.65~ -0.70 for the residential sector, estimated from time-series data (see IEA, op. cit., pp. 93-96). Apart from the theoretical consideration that time-series data are not likely to yield reliable estimates of long-run price elasticities, the IEA's price elasticities will overestimate the demand when tested against historical data. IEA partially compensates for this problem by adjusting income elasticities downwards, but it is not clear whether the adjustments are roughly equivalent to the long-term price elasticities used in our base case.

Table 5.9: A COMPARISON OF WEPM AND IEA PROJECTIONS

(MBDOE)

	1985	1990	2000
World Primary Energy Demand			
WEPM /a	92.5-93.9	101.8-103.5	131.6-139.1
IEA	101.4-103.9	113.6-121.9	148.2-172.9
(% Difference)			
World Petroleum Demand /b			
WEPM	43.2-44.4	45.2-48.3	52.5-66.2
IEA	46.4-47.7	48.1-53.2	56.0-71.6
(% Difference)			
Non-OPEC Petroleum Supplies /c			
WEPM	23.2	24.8	29.6
IEA	24.6-25.6	22.3-26.3	22.9-28.9
Demand for OPEC Petroleum			
WEPM	21.1-21.2	21.5-23.5	24.6-36.6
IEA	20.8-23.1	21.8-30.9	27.1-48.7

/a Consumption of primary electricity is converted into oil equivalents on the basis of equivalent thermal energy needed to replace the primary electricity in order to make the figures comparable.

/b Demand for total liquid fuels.

/c Supplies of all liquid fuels including net exports from centrally planned economies.

Sources: World Bank, Economic Analysis & Projections Department.
IEA, World Energy Outlook, Tables 1.3, 4.9 and 4.10.

difference in the primary energy demand projections. 1/ It appears that IEA foresees greater interfuel substitution than the WEPM results. The petroleum share in total primary energy demand declines from 45.8% in 1985 to 37.8% in 2000 in IEA's low demand scenario compared with a decline from 46.7% to 40% in the WEPM base case for the same period. Furthermore, the projected shift in the petroleum share in IEA's high demand scenario is about the same as in its low demand scenario, although the OPEC oil price assumption is different. In WEPM simulations with the constant OPEC price assumption, the share of coal in world primary energy consumption increases from 18.5% in 1978 to 23.9% in 1985, but declines to 21.8% in 1990 and 18.7% in the year 2000. IEA, on the other hand, projects that the share of coal will continue to increase from 20.7% in 1985 to 24.7% in the year 2000, regardless of the OPEC price assumption. It is not clear what IEA assumed about the price differential between petroleum and coal. But the insensitivity of the petroleum share to its price in IEA projections seems prima facie inconsistent.

With OPEC petroleum supply availabilities put at 27-29 million b/d in 1990 and 24-28 million b/d in the year 2000, IEA finds likely a worldwide excess demand for petroleum of 0-4 million b/d by 1990 and 9-21 million b/d by the year 2000, unless the price of OPEC oil rises to clear the market. The WEPM results suggest that an excess demand situation is not likely to develop until the early 1990s at today's OPEC price of petroleum. The main difference is the assumption about the price elasticity of energy demand. IEA's pessimistic outlook is based on relatively small demand adjustments to higher energy prices, which is contrary to recent trends and well-accepted econometric evidence.

5.4. Long-Term OPEC Pricing and Production

The WEPM model was used to generate an array of OPEC production and revenue paths corresponding to alternative long-term pricing paths for OPEC

1/ Royal Dutch-Shell, one of the mavericks, sees world petroleum demand remaining at around 45 million b/d in 1985 and increasing only to 46-47 million b/d by 1990, on the basis of somewhat slower economic growth projections than our base case. At this level of world demand, OPEC production will be 21-22 million b/d and net exports, 17-18 million b/d in 1990.

oil. Five alternative pricing paths, shown in Figure 5.6, are postulated, broadly representing the range of possibilities open to OPEC for the period up to the year 2000. Four of them assume that the price of OPEC oil in the year 2000 will be constrained by the availability of a backstop technology at a cost of $56 per barrel (in 1981 dollars). One of them (OP5) assumes that introduction of a backstop technology will be delayed until 2010, and that the OPEC oil price will increase to $43 in 2000 and to $56 in 2010.

Given the uncertainties of the market, the adoption of a long-term pricing path does not appeal as a realistic modus operandi for OPEC. OPEC pricing is more likely to follow myopic behavior, relying heavily on current market information and modifying its policy as new circumstances arise. However, consideration of its long-term interests is a relevant and important one, particularly for the capital-surplus OPEC group. Evaluation of long-term interests should constitute an integral part of OPEC's frame of reference, not so much as a basis for choosing a long-term pricing path, but as a means of assessing the long-term implications of its short-term pricing decisions.

The following results should be interpreted with due attention to the two important limitations of the model. One is the lack of feedback from OPEC oil price increases to economic growth; the other is the absence of non-OPEC petroleum supply responses to OPEC oil price increases. These limitations would bias the results in favor of a more aggressive OPEC pricing policy.

OPEC pricing paths will be examined under two different assumptions about demand uncertainties: the base case and the low demand adjustment case. Also discussed are the implications of faster economic growth, supply uncertainties, and the pricing policies of the oil-importing countries.

Demand for OPEC Oil and OPEC Revenues

OPEC pricing decisions depend critically on the price elasticity of non-OPEC demand for OPEC oil. It is possible to derive this price elasticity implied by the WEPM structure and parameters. Table 5.10 shows this elasticity for the two alternative demand adjustment cases.

Demand for OPEC oil is inelastic over the short run, increases to close to unitary elasticity in the medium run and becomes elastic over the long run. 1/ OPEC, therefore, can substantially increase revenues over the

---

1/ If this long-run price elasticity is less than unity (inelastic), OPEC can obtain ever larger revenues by increasing prices and producing smaller amounts in all future years. OPEC can maximize revenues by minimizing production, which is contradictory to recent experience.

FIGURE 5.6

ALTERNATIVE SCENARIOS FOR OPEC PRICING
(1981$/BOE)

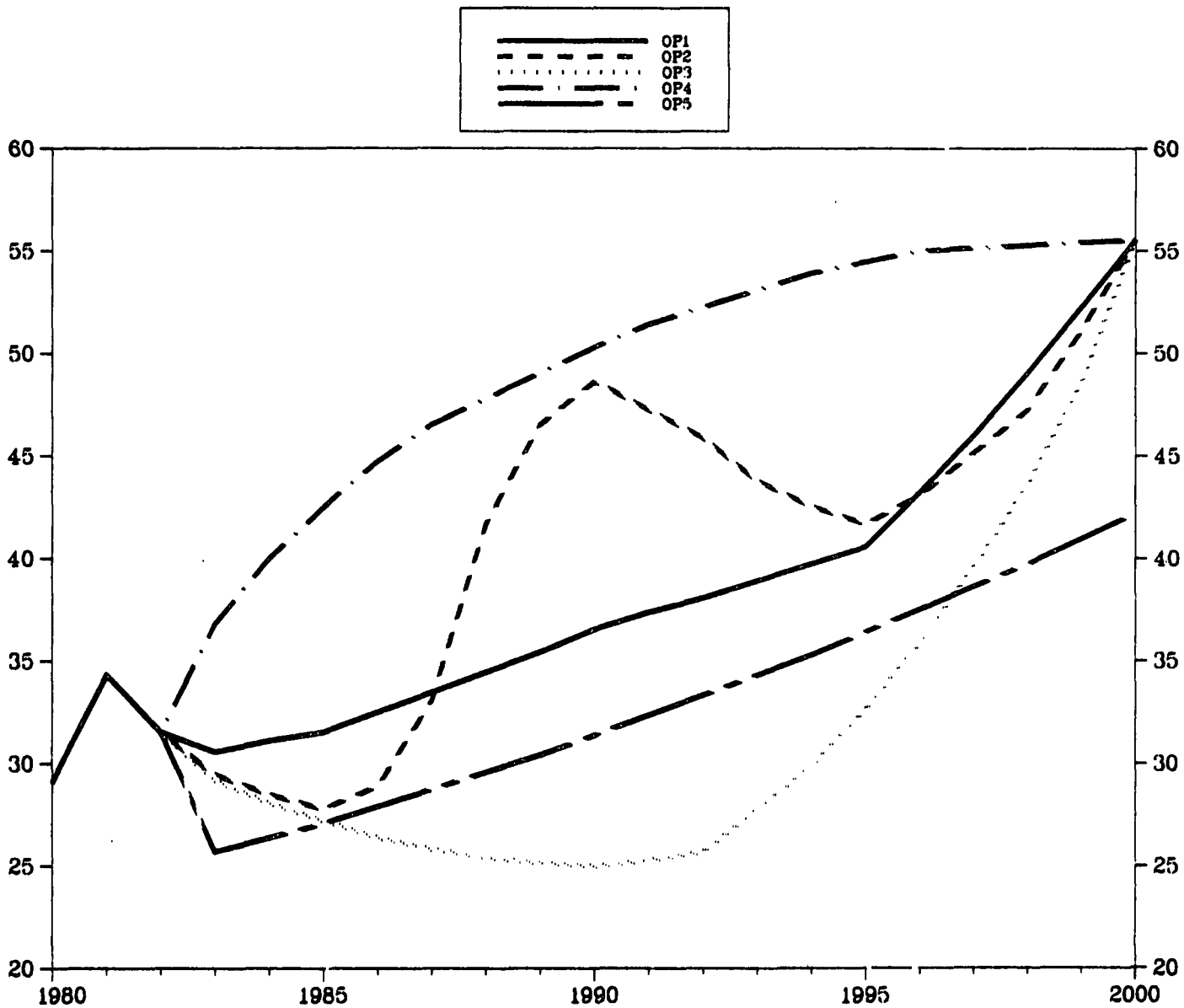


Table 5.10: PRICE ELASTICITY OF NON-OPEC DEMAND FOR OPEC OIL /a

	Short Term	Medium Term		Long Term	
	1983	1985	1990	1995	2000
Base Case	-0.39	-0.56	-0.95	-1.26	-1.50
Low Demand Adjustment Case	-0.18	-0.50	-0.85	-1.12	-1.35

/a Derived from controlled experiments with WEPM. As a basis for comparison, WEPM was run twice, one assuming constant real price for OPEC crude oil for the 1983-2000 period, and the other assuming 10% higher prices than the first one for the same period. The percentage difference in the demand for OPEC oil between the two runs divided by 10 gives the price elasticity of the demand for OPEC oil.

Source: World Bank, Economic Analysis and Projections Department.

short run by raising crude oil prices, but only at the cost of long-term revenue losses, while medium-term revenues would not be significantly affected by the price changes. These elasticities are used to project OPEC exports beyond the year 2000, the terminal year of WEPM simulations.

OPEC Pricing Under the Base Case

The model was run for the five alternative OPEC pricing paths, while keeping all other base-case assumptions. The resulting demand for OPEC oil is allocated between the capital-surplus and capital-deficit OPEC groups, using the alternative prorationing schemes shown in Table 2.3. The present values of OPEC revenues were then calculated, using the objective function (2.5). The base-case discount rates are 5% for the revenues necessary for imports and 2% for surplus revenues. Alternative discount rates are 10% for the revenues for imports and 5% for surplus revenues.

OPEC exports and revenues corresponding to each pricing path are shown in Table 5.11. The lower (OP3) and upper (OP4) extreme pricing paths produce the upper and lower bounds for OPEC exports, with the base case (OP1) and cyclical price path (OP2) yielding intermediate results. The low steady price increase scenario (OP5) results in the highest level of demand for OPEC oil for all the years.

Table 5.11: OPEC PETROLEUM EXPORTS AND REVENUES UNDER ALTERNATIVE PRICING PATHS

	OP1	OP2	OP3	OP4	OP5
Exports (MBDOE)					
1983	18.5	18.6	18.7	17.4	19.6
1985	18.3	19.2	19.4	15.5	19.8
1990	18.1	15.3	23.1	12.4	20.7
1995	20.2	18.0	26.6	13.1	23.0
2000	19.8	18.8	23.2	15.8	24.9
Revenues (Billion 1981 $)					
1983	208.6	202.8	185.5	236.6	201.7
1985	212.9	197.5	198.3	242.7	195.4
1990	244.3	274.5	240.2	229.5	213.5
1995	303.4	276.9	308.9	264.1	321.2
2000	405.5	385.4	388.7	324.1	476.9
Cumulative Production 1978-2000 (Billion Barrels)	186.9	177.9	204.7	152.2	215.0
Remaining Reserves /a in 2001 (Billion Barrels)	248.7	258.1	230.9	283.4	220.6
Remaining Reserves /b in 2001 (Billion Barrels)	455.5	464.5	437.7	490.2	427.4

/a Using the published data on proven reserves in 1978.

/b Assuming 1.5 times the published proven reserves for the capital-surplus group, and 1.3 times for the capital-deficit group.

Source: World Bank, Economic Analysis and Projections Department.

Revenue paths corresponding to each price path show different intertemporal patterns. Export revenue increases steadily for OP1 and OP3, but for the others revenue declines for some of the years. It will be shown below that non-steady revenue paths yield lower present value revenues than the steady ones. OPEC is expected to deplete less than half of its currently proven reserves by the year 2000. It is, however, expected that OPEC will

find substantial new reserves in the years ahead. As a first approximation, we assume that reserve additions will ultimately amount to 50% of the currently proven reserves of the capital-surplus group and 30% of those of the capital-deficit group. Under this assumption, OPEC by the year 2000 will be left with roughly 70% of the currently proven reserves plus the reserve additions. About 95% of the remaining reserves will be in the capital-surplus OPEC countries.

Table 5.12 shows, for the five price scenarios, the present value of export revenues up to the year 2000 and the reserves remaining at the end of that year. The latter is calculated by the same method as the former except that the demand for OPEC oil is projected using the elasticities shown in Table 5.10 and assuming 2% p.a. growth in non-OPEC GDP. For OPEC as a whole, the base-case pricing path yields a higher present value of export revenues for the period 1978-2000 than the other alternatives, regardless of the assumptions about prorationing and discount rates. The higher pricing path (OP4) yields the lowest present value of revenues. Lower pricing paths (OP3 and OP5) yield higher revenues than higher pricing paths (OP2 and OP4). The differences between them, however, are relatively small; for example, reading across the first row of Table 5.12, the highest present value is only 6% higher than the lowest one.

OP3 is the polar case to OP4. The present value of OPEC revenues for OP3 is higher than that for OP4. Substantial price increases over the medium term (OP4) bring higher revenues for the period than the case of lower medium-term prices (OP3), but the long-term revenues suffer to such an extent as to more than wipe out the medium-term gains. This seems to imply that OPEC is better off by choosing a moderate pricing path for the medium term in the wake of the drastic price increases of 1979/80, followed by fairly steep increases in the 1990s when demand for petroleum picks up strongly again.

The cyclical path (OP2) does not perform as well as the gradual price increase scenarios (OP1 and OP3). OP2 postulates another round of major price increases in 6-9 years after the 1979/80 price shock, about the same interval as that between the 1973/74 and 1979/80 petroleum price increases. The same cycle is repeated for the 1990s. However, the poor performance of this particular cycle could be interpreted more as a poor timing rather than as a validation of the hypothesis that a cyclical pricing strategy is suboptimal.

Since it is assumed that OPEC must sell all remaining reserves at a constant price after backstop technologies are introduced, the faster the remaining reserves are exhausted, the greater will be the present value of revenues to be obtained from remaining reserves. Therefore, larger remaining reserves would not necessarily mean greater present values. It is shown in Table 5.12 that the alternative pricing scenarios produce significantly different estimates for the present value of remaining reserves. The differences are sufficiently large to change the rankings of the alternative pricing paths in terms of the total present values. The low pricing path (OP3) now looks better than the base-case pricing path (OP1). Higher pricing paths such as OP4 result in lower present values for the remaining reserves, despite the fact that the remaining reserves are larger. A delay in introduction of backstop technologies as postulated under OP5 makes OPEC reserves more valuable than when there is no delay. The total present value under OP5 is lower than those under OP1 or OP3. This would indicate that OP5 is suboptimal. One can, therefore, conclude that, when introduction of backstop technologies is delayed, the optimal pricing path would be one that is higher than OP5, or even higher than OP1.

Production prorationing between the two OPEC groups is seen to make a significant difference in the present value estimates for each group. Since the capital-deficit group is likely to be left with only small remaining reserves by the year 2000, their preferred choice would be higher pricing and a larger share of OPEC production for the period up to 2000. The best choice for the capital-deficit group among those considered here is the combination of a high pricing path and high production shares (OP4 and prorationing regime B). The least acceptable to this group is a low production share (prorationing regime C), regardless of the pricing paths considered. From the point of view of the capital-surplus group, the most preferred choice is a combination of a low pricing path and high production shares (OP3 and prorationing regime C), while the least preferred is the high pricing path (OP4), regardless, for the most part, of the prorationing options considered. A plausible compromise between the two groups could be the choice of OP1 or OP3 together with the prorationing regime B. 1/

1/ The results show that the prorationing regime A (constant production shares over time) is inefficient. This conforms with the results of Hnyilicza and Pindyck (1976).

Table 5.12: PRESENT VALUES OF OPEC EXPORT REVENUES AND RESERVES: BASE-CASE DEMAND ADJUSTMENTS
(Billions of constant 1981 dollars)

		OP1			OP2			OP3			OP4			OP5		
		CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC
At Base-Case Discount Rates																
P.V. of Export	A	3,010	854	3,864	2,946	845	3,791	2,996	838	3,834	2,817	831	3,647	2,929	833	3,762
Revenues (1978-2000)	B	2,754	1,089	3,843	2,681	1,094	3,774	2,775	1,031	3,806	2,549	1,075	3,624	2,680	1,056	3,736
	C	3,440	557	3,997	3,369	551	3,920	3,418	549	3,968	3,223	543	3,766	3,347	545	3,892
P.V. of Remaining	A	4,795	298	5,693	4,577	311	4,888	5,160	200	5,360	4,273	365	4,639	4,643	216	4,859
Reserves	B	5,362	155	5,517	5,115	180	5,295	5,278	56	5,784	4,810	232	5,042	5,173	86	5,259
	C	4,972	345	5,316	4,781	339	5,120	5,206	321	5,526	4,540	359	4,899	4,734	319	5,053
Total	A	7,805	1,153	8,958	7,524	1,156	8,679	8,156	1,039	9,195	7,090	1,196	8,286	7,572	1,049	8,621
P.V.	B	8,117	1,244	9,361	7,796	1,273	9,069	8,503	1,087	9,590	7,359	1,307	8,666	7,852	1,143	8,995
	C	8,412	902	9,314	8,150	890	9,040	8,624	870	9,494	7,764	902	8,666	8,081	864	8,945
At High Discount Rates																
P.V. of Export	A	2,199	559	2,759	2,158	556	2,713	2,169	544	2,713	2,078	558	2,636	2,133	546	2,678
Revenues (1978-2000)	B	1,980	744	2,724	1,931	753	2,684	1,977	690	2,667	1,849	750	2,599	1,920	716	2,636
	C	2,534	386	2,920	2,487	384	2,871	2,495	379	2,873	2,397	385	2,782	2,457	378	2,836
P.V. of Remaining	A	955	81	1,037	895	83	978	1,112	61	1,173	770	91	861	962	63	1,025
Reserves in 2001	B	1,133	41	1,173	1,061	44	1,106	1,310	18	1,329	922	51	973	1,133	26	1,159
	C	1,044	73	1,117	986	71	1,057	1,169	72	1,241	865	72	937	1,023	71	1,094
Total	A	3,154	645	3,795	3,052	639	3,691	3,281	605	3,886	2,847	649	3,496	3,095	609	3,704
P.V.	B	3,113	785	3,898	2,993	797	3,790	3,287	708	3,995	2,772	801	3,572	3,053	742	3,795
	C	3,577	459	4,037	3,473	455	3,929	3,663	450	4,114	3,262	457	3,719	3,480	450	3,930

Note: The symbols A,B and C stand for the alternative OPEC production prorationing regimes shown in Table 2.3.
Discount rates for the base case are 5% for revenues used for imports and 2% for surplus revenues.
The high case discount rates are twice the base case rates for each revenue categories.

Source: World Bank, Economic Analysis and Projections Department.

The relative rankings by present value of revenues of the alternative pricing scenarios are not significantly affected by the discount rate. Other things being equal, higher discount rates would favor current revenues to future revenues and, therefore, higher prices now rather than later. Higher discount rates, therefore, would improve the desirability of OP4 relative to OP3. Results in Table 5.12 show that this is indeed the case, 1/ but not sufficiently so as to reverse the ranking even at twice the base-case discount rates.

The higher the discount rate, the greater the incentive for the two OPEC groups to obtain a larger share of the total OPEC production. The best choice for the capital-deficit group among the options considered under the high discount rates is the same as the one under the base-case discount rates. However, this group will find that production shares matter more in terms of revenues under higher discount rates. The same is also the case for the capital-surplus group. It appears from the results that higher discount rates make production prorationing relatively more important than the choice of pricing path in the trade-off between the two, for both of the two OPEC groups.

The case of Low Demand Adjustments

An important uncertainty in the choice of a pricing path for OPEC oil is the degree of energy demand adjustments to energy prices. Will the relative ranking of the alternative pricing paths change significantly if the price elasticities are lower than those assumed for the base case? Table 5.13 provides on answer to this question under the assumption that the price elasticities of final demand are 20% lower than the base case.

As expected, low price elasticities of final energy demand result in a present value of export revenues 10-20% higher than the base case for all pricing paths. The percentage increases are greater for the higher pricing paths than for the lower pricing paths. The present value of exports under

---

1/ The percentage difference in present value of export revenues between OP3 and OP4 is 3% under the higher discount rates compared with 5% difference under the base-case discount rates.

Table 5.13: PRESENT VALUES OF OPEC EXPORTS AND RESERVES: THE LOW DEMAND ADJUSTMENT CASE
(Billions of constant 1981 dollars)

		OP1			OP2			OP3			OP4			OP5		
		CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC	CSEX	CDOP	OPEC
At Base-Case Discount Rates																
P.V. of Export	A	3,402	938	4,340	3,427	949	4,375	3,319	907	4,226	3,377	957	4,334	3,269	907	4,175
Revenues (1978-2000)	B	3,124	1216	4,340	3,128	1,254	4,382	3,098	1,116	4,213	3,066	1,265	4,331	2,999	1,169	4,168
	C	3,885	605	4,490	3,916	609	4,527	3,784	590	4,374	3,862	612	4,474	3,733	588	4,320
P.V. of Remaining	A	5,565	248	5,814	5,615	269	5,884	5,848	145	5,994	5,261	337	5,599	5,419	160	5,580
Reserves in 2001	B	6,155	100	6,255	6,215	122	6,338	6,416	0	6,416	5,844	201	6,045	5,994	15	6,009
	C	5,648	351	5,999	5,746	350	6,096	5,789	325	6,115	5,474	374	5,849	5,410	332	5,742
Total P.V.	A	5,967	1,186	10,153	9,042	1,218	10,260	9,167	1,053	10,220	8,638	1,294	9,932	8,668	1,067	9,755
	B	9,279	1,316	10,595	9,343	1,377	10,720	9,514	1,116	10,630	8,910	1,466	10,376	8,992	1,184	10,176
	C	9,533	957	10,489	9,663	959	10,622	9,573	915	10,489	9,336	987	10,323	9,143	920	10,063
At Higher Discount Rates																
P.V. of Export	A	2,494	607	3,101	2,520	615	3,134	2,411	584	2,995	2,503	633	3,137	2,390	587	2,977
Revenues (1978-2000)	B	2,255	836	3,092	2,265	870	3,135	2,211	756	2,967	2,238	889	3,127	2,159	799	2,958
	C	2,868	414	3,282	2,899	417	3,317	2,769	403	3,171	2,883	424	3,307	2,749	403	3,152
P.V. of Remaining	A	1,255	73	1,329	1,228	78	1,306	1,428	47	1,475	1,077	91	1,168	1,238	50	1,288
Reserves in 2001	B	1,470	30	1,500	1,439	35	1,475	1,662	0	1,662	1,268	50	1,319	1,451	5	1,456
	C	1,331	80	1,411	1,315	79	1,394	1,456	78	1,534	1,179	81	1,260	1,276	78	1,354
Total P.V.	A	3,749	680	4,429	3,748	693	4,441	3,839	630	4,470	3,580	725	4,305	3,628	638	4,266
	B	3,725	867	4,592	3,704	905	4,610	3,873	756	4,630	3,507	939	4,446	3,610	804	4,414
	C	4,198	494	4,693	4,214	497	4,710	4,225	481	4,705	4,062	506	4,568	4,025	481	4,506

Note: Refer to the note in Table 5.12.

Source: World Bank, Economic Analysis and Projections Department.

OP2 and OP4 are now slightly higher or only marginally lower than that under OP1, while that of OP3 is lower. The present value of remaining reserves also increases more for the higher pricing paths than for the lower pricing paths. It is interesting to note that in terms of total present value the cyclical path (OP2) now looks superior to the other alternatives. The cyclical path takes advantage of faster increases in demand for OPEC oil in the late 1980s and early 1990s than in the base case. However, this cannot be taken as an indication that the cyclical pricing strategy is better than the strategy of steady price increases. A steady pricing path slightly higher than the base-case pricing paths for the 1983-2000 period could have produced higher revenues than the cyclical path.

A lower price elasticity of the demand for OPEC oil brings a greater benefit to the capital-surplus group than to the capital-deficit group in terms of present value of export revenues and remaining reserves. This is simply because the capital-surplus group has a larger share of OPEC production and reserves than the capital-deficit group. The capital-deficit group, as in the base case, gets higher revenues under higher pricing paths and larger shares of OPEC production. Production prorationing, however, becomes less of an issue when total OPEC production is higher. 1/

The assumption of higher discount rates makes only a minor difference in the relative ranking of the alternative pricing paths. The higher pricing path (OP4) now yields the largest present value of export revenues, but the present value of remaining reserves decline more than under other pricing paths because it takes longer to exhaust the remaining reserves under OP4 than under other pricing options. For the same reason, the low pricing path now yields a higher present value of total revenues than the cyclical path.

Impact of Alternative Assumptions on OPEC Revenues

OPEC revenues depend not only on the choice of a pricing and production path but also on economic growth and energy supply/demand adjustments in non-OPEC countries. These in fact constitute the important uncertainties

---

1/ The percent difference in total revenues for the capital-deficit group between prorationing regimes B and C is smaller under the low demand adjustment scenario than under the base-case demand adjustment scenario.

facing OPEC. To what extent do these uncertainties affect the net worth of OPEC oil? Table 5.14 shows the present value calculations for several variations in the base-case assumptions.

Economic growth and the degree of energy demand adjustments in non-OPEC countries are seen to make a substantial difference in the present value of OPEC petroleum (Table 5.14). A 20% reduction in the price elasticities of final energy demands increases the present value of OPEC exports by 12.3%, that of remaining reserves by 20.7%, and the total present value by 15.9%. A 20% reduction in GDP growth rates for the period 1983-2000 results in an 11.4% decline in the present value of export revenues, a 30.8% fall in that of remaining reserves, and a 20% decline in the total present value. These differences are substantially larger than the differences in the present values corresponding to the alternative pricing paths.

It is the capital-surplus group of OPEC that reaps most of the revenue increases from high economic growth and low energy demand adjustments in non-OPEC countries. This group would be more interested in fostering high economic growth than the capital-deficit group--even at the expense of lower OPEC oil prices--if lower petroleum prices stimulate faster economic growth.

The impact of a low nuclear power supply scenario is shown to be minimal (low nuclear power scenario in Table 5.14). A shortfall in nuclear energy supplies results mostly in greater demands for thermal coal, with only a small impact on the demand for petroleum. The present value of export revenues and remaining reserves, therefore, are increased only insignificantly.

Further decontrol of the price of natural gas in non-OPEC countries is seen to increase the demand for OPEC oil and OPEC revenues. The present value of exports and remaining reserves is increased only by less than one percent when the natural gas prices to final users are increased by an average of 15% over the base case. This result, however, should be taken with caution because the supply responses of natural gas in non-OPEC countries are ignored in this calculation.

Imposition of a tariff on crude oil imports by non-OPEC countries could have a serious adverse impact on OPEC revenues and the value of reserves. A 30% tariff leads to a 17.5% reduction below the base case in the

Table 5.14: PRESENT VALUES OF OPEC EXPORTS AND RESERVES UNDER ALTERNATIVE ASSUMPTIONS /a

(Billions of constant 1981 dollars)

	Base Case	Low Demand Adjustment	High Growth	Low Growth	High Growth and Low Demand Adjustment	Low Nuclear	Further Price Decontrol	Import Tariff
Present Value of Exports								
CSEX	3,010	3,402	3,394	2,645	3,830	3,024	3,045	2,460
CDOP	854	938	934	778	1,026	857	862	739
OPEC	3,864	4,340	4,328	3,422	4,856	3,881	3,907	3,199
Present Value of Remaining Reserves								
CSEX	4,795	5,565	5,738	3,834	6,509	4,874	4,842	3,869
CDOP	298	248	242	319	170	285	284	320
OPEC	5,093	5,814	5,980	4,153	6,679	5,160	5,126	4,189
Total Present Value								
CSEX	7,805	8,967	9,131	6,479	10,339	7,899	7,887	6,329
CDOP	1,153	1,186	1,176	1,096	1,196	1,142	1,146	1,059
OPEC	8,958	10,153	10,308	7,575	11,535	9,041	9,033	7,388

/a All scenarios assume the OPEC pricing path OP1, the prorationing scheme A, and the base-case discount rates. High and low economic (GDP) growth scenarios assume 20% higher or lower GDP growth rates for 1983-2000. Low demand adjustment scenario assumes 20% lower price elasticities of final energy demands. Low nuclear scenario assumes 20% less supplies of nuclear electricity by the year 2000, with linear interpolation for the intervening years. Further price decontrol scenario assumes that an additional 20% of the gap between the domestic prices and what is deemed as the maximum level of decontrol will be removed by the year 2000, on top of the base-case level of decontrol. Import tariff scenario assumes an imposition of 30% tax on crude oil imports for 1983-2000 in oil-importing countries.

Source: World Bank, Economic Analysis and Projections Department.

present value of OPEC exports and remaining reserves. The capital-surplus group suffers a 19% loss in the present value of its export revenues and remaining reserves, while the loss of the capital-deficit group is 9%. About 70% of the discounted present value of tariff revenues of the oil-importing countries constitutes a net loss of revenues on the part of OPEC.

ANNEX 5.1

LIST OF EQUATIONS AND VARIABLES IN WEPM

A. LIST OF EQUATIONS

DEMAND BLOCK

D1. TRANSPORTATION SECTOR

Gasoline Demand

Stock of Cars

$$\ln\left(\frac{CAR}{POP}\right) = \alpha_0 + \alpha_1 \cdot \ln\left(\frac{GDP}{POP}\right) + \alpha_2 \cdot \ln\left(\frac{GDP}{POP}\right)^2 + \alpha_3 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln(PGAS_{t-j+1})$$

	PARAMETER VALUES		
	α_1	α_2	α_3
NOAM	1.74	-0.24	-0.10
WEUR	1.69	-0.24	-0.10
JANZ	1.88	-0.24	-0.10
CSEX	2.34	-0.24	-0.10
CDOP	1.26	-0.24	-0.10
NOEX	1.38	-0.24	-0.10
OIDC	1.24	-0.24	-0.10

Lag Structure

$\omega_1 = 0.4$ $\omega_2 = 0.3$
$\omega_3 = 0.2$ $\omega_4 = 0.1$

Gasoline Demand per Car

$$\ln\left(\frac{GAS}{CAR}\right) = \beta_0 + \beta_1 \cdot \ln\left(\frac{GDP}{POP}\right) + \beta_2 \cdot \ln\left(\frac{CAR}{POP}\right) + \beta_3 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln(PGAS_{t-j+1})$$

	PARAMETER VALUES		
	β_1	β_2	β_3
NOAM	0.38	-0.30	-0.40
WEUR	0.52	-0.55	-0.40
JANZ	0.62	-0.84	-0.40
CSEX	0.60	-0.52	-0.40
CDOP	0.52	-0.46	-0.40
NOEX	0.41	-0.39	-0.40
OIDC	0.52	-0.57	-0.40

Lag Structure

$\omega_1 = 0.27$ $\omega_2 = 0.09$ $\omega_3 = 0.13$
$\omega_4 = 0.17$ $\omega_5 = 0.05$ ω_6 to
$\omega_9 = 0.04$ ω_{10} to $\omega_{11} = 0.03$
ω_{12} to $\omega_{16} = 0.01$

Diesel Oil Demand

$$\ln (DSL) = \beta_o + \beta_1 \cdot \ln (GDP) + \beta_2 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln (PDSL_{t-j+1})$$

PARAMETER VALUES

	β_1	β_2
NOAM	2.0	-0.3
WEUR	1.3	-0.3
JANZ	1.0	-0.3
CSEX	1.5	-0.3
CDOP	1.3	-0.3
NOEX	1.3	-0.3
OIDC	1.3	-0.3

Lag Structure

$\omega_1 = 0.4$ $\omega_2 = 0.3$
$\omega_3 = 0.2$ $\omega_4 = 0.1$

Aviation Fuel Demand

$$\ln (JAK) = \beta_0 + \beta_1 \cdot \ln (GDP) + \beta_2 \cdot \ln (POP) + \beta_3 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln (PJAK_{t-j+1})$$

Parameter Values

	β_1	β_2	β_3
NOAM	0.9	-0.65	-0.52
WEUR	1.2	-0.75	-0.52
JANZ	1.5	-0.80	-0.52
CSEX	1.7	-1.20	-0.52
CDOP	1.7	-1.00	-0.52
NOEX	1.7	-1.00	-0.52
OIDC	1.5	-1.00	-0.52

Lag Structure

$\omega_1 = 0.19$ $\omega_2 = 0.10$ $\omega_3 = 0.06$
$\omega_4 = 0.06$ $\omega_5 = 0.04$ $\omega_6 = 0.06$
$\omega_7 = 0.06$ $\omega_8 = 0.08$ ω_9 to
$\omega_{10} = 0.06$ $\omega_{11} = 0.06$ ω_{12} to
$\omega_{14} = 0.04$ ω_{15} to $\omega_{18} = 0.02$

Rail and Other Transportation Fuel Demand

$$\ln (ROT) = \beta_0 + \beta_1 \cdot \ln (GDP) + \beta_2 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln (PROT_{t-1+1})$$

	Parameter Values	
	β_1	β_2
NOAM	0.5	-0.28
WEUR	0.4	-0.28
JANZ	0.5	-0.28
CSEX	0.5	-0.28
CDOP	0.5	-0.28
NOEX	0.5	-0.28
OIDC	0.7	-0.28

Lag Structure

ω_1 = 0.18	ω_2 = 0.04	ω_3 = 0.07
ω_4 = 0.07	ω_5 = 0.11	ω_6 = 0.14
ω_7 = 0.18	ω_8 = 0.11	ω_9 = 0.07
ω_{10} = 0.04		

D2. INDUSTRIAL SECTOR

Total Industrial Energy Demand

$$\ln (ENI) = \beta_0 + \beta_1 \cdot \ln (GDP) + \beta_3 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln (PENI_{t-j+1})$$

	Parameter Values	
	β_1	β_3
NOAM	1.00	-0.75
WEUR	0.90	-0.85
JANZ	0.95	-0.75
CSEX	1.20	-0.35
CDOP	1.15	-0.35
NOEX	1.15	-0.35
OIDC	1.10	-0.40

Lag Structure

ω_1 = 0.15	ω_2 = 0.10	ω_3 = 0.07
ω_4 = 0.04	ω_5 = 0.05	ω_6 = 0.06
ω_7 = 0.07	ω_8 = 0.07	ω_9 = 0.06
ω_{10} = 0.06	ω_{11} = 0.05	ω_{12} = 0.05
ω_{13} = 0.04	ω_{14} = 0.04	ω_{15} = 0.03
ω_{16} = 0.03	ω_{17} = 0.02	ω_{18} = 0.01

Industrial Fuel Shares

Coal Cost Share

$$\frac{COALI \cdot PCOALI}{ENI \cdot PENI} = \alpha_C - 0.043 \cdot \omega(L) \cdot \ln\left(\frac{PCOALI}{POILI}\right)$$

$$+ 0.0025 \cdot \omega(L) \cdot \ln\left(\frac{PNGI}{POILI}\right) + 0.025 \cdot \omega(L) \cdot \ln\left(\frac{PELI}{POILI}\right)$$

Natural Gas Cost Share

$$\frac{NGI \cdot PNGI}{ENI \cdot PENI} = \alpha_N + 0.0025 \cdot \omega(L) \cdot \ln\left(\frac{PCOALI}{POILI}\right)$$

$$- 0.073 \cdot \omega(L) \cdot \ln\left(\frac{PNGI}{POILI}\right) + 0.049 \cdot \omega(L) \cdot \ln\left(\frac{PELI}{POILI}\right)$$

Electricity Cost Shares

$$\frac{ELI \cdot PELI}{ENI \cdot PENI} = \alpha_E + 0.025 \cdot \omega(L) \cdot \ln\left(\frac{PCOALI}{POILI}\right)$$

$$+ 0.014 \cdot \omega(L) \cdot \ln\left(\frac{PNGI}{POILI}\right) + 0.049 \cdot \omega(L) \cdot \ln\left(\frac{PELI}{POILI}\right)$$

Petroleum Cost Share

$$\frac{OILI \cdot POILI}{ENI \cdot PENI} = \alpha_O + 0.016 \cdot \omega(L) \cdot \ln\left(\frac{PCOAI}{POILI}\right)$$

$$+ 0.056 \cdot \omega(L) \cdot \ln\left(\frac{PELI}{POILI}\right) - 0.088 \cdot \omega(L) \cdot \ln\left(\frac{PELI}{POILI}\right)$$

Lag Structure		
$\omega_1 = 0.045$	$\omega_2 = 0.082$	$\omega_3 = 0.109$
$\omega_4 = 0.127$	$\omega_5 = 0.136$	$\omega_6 = 0.136$
$\omega_7 = 0.127$	$\omega_8 = 0.109$	$\omega_9 = 0.082$
$\omega_{10} = 0.045$		

Industrial Sector Final Energy Demand

$$ENI = COALI + NGI + ELI + OILI$$

Thermally Adjusted Industrial Energy Price

$$PENI = (0.7 \cdot PCOALI \cdot COALI + 0.85 \cdot PNGI \cdot NGI + 0.99 \cdot PELI \cdot ELI + 0.8 \cdot POILI \cdot OILI)/ENI.$$

D3. RESIDENTIAL SECTOR

Total Residential Energy Demand

$$\ln\left(\frac{ENR}{POP}\right) = \beta_0 + \beta_1 \cdot \ln\left(\frac{GDP}{POP}\right) + \beta_3 \cdot \sum_{j=1}^{t} \omega_j \cdot \ln(PENR_{t-j+1})$$

	Parameter Values	
	β_1	β_3
NOAM	0.85	-0.80
WEUR	1.10	-0.70
JANZ	0.95	-0.80
CSEX	1.35	-0.50
CDOP	1.25	-0.50
NOEX	1.20	-0.50
OIDC	1.20	-0.60

Lag Structure

$\omega_1 = 0.20$ $\omega_2 = 0.12$ $\omega_3 = 0.08$
$\omega_4 = 0.07$ $\omega_5 = 0.06$ $\omega_6 = 0.06$
$\omega_7 = 0.05$ $\omega_8 = 0.05$ ω_9 to
$\omega_{12} = 0.04$ ω_{13} to $\omega_{15} = 0.03$
ω_{16} to $\omega_{18} = 0.02$

Residential Fuel Shares

Coal Cost Share

$$\frac{COALR \cdot PCOALR}{ENR \cdot PENR} = \alpha_C - 0.0 \cdot \omega(L) \cdot \ln\left(\frac{PCOALR}{POILR}\right) + 0.000019 \cdot \omega(L) \cdot \ln\left(\frac{PNGR}{POILR}\right) - 0.000019 \cdot \omega(L) \cdot \ln\left(\frac{PELR}{POILR}\right)$$

Natural Gas Cost Share

$$\frac{NGR \cdot PNGR}{ENR \cdot PENR} = \alpha_N + 0.000019 \cdot \omega(L) \cdot \ln\left(\frac{PCOALR}{POILR}\right) - 0.13 \cdot \omega(L) \cdot \ln\left(\frac{PNGR}{POILR}\right) + 0.084 \cdot \omega(L) \cdot \ln\left(\frac{PELR}{POILR}\right)$$

Electricity Cost Share

$$\frac{ELR \cdot PELR}{ENR \cdot PENR} = \alpha_E - 0.000019 \cdot \omega(L) \cdot \ln\left(\frac{PCOALR}{POILR}\right)$$

$$+ 0.084 \cdot \omega(L) \cdot \ln\left(\frac{PNGR}{POILR}\right) - 0.11 \cdot \omega(L) \cdot \ln\left(\frac{PELR}{POILR}\right)$$

Petroleum Cost Share

$$\frac{OILR \cdot POILR}{ENR \cdot PENR} = \alpha_0 - 0.0 \cdot \omega(L) \cdot \ln\left(\frac{PCOALR}{POILR}\right)$$

$$+ 0.051 \cdot \omega(L) \cdot \ln\left(\frac{PNGR}{POILR}\right) + 0.026 \cdot \omega(L) \cdot \ln\left(\frac{PELR}{POILR}\right)$$

Lag Structure		
$\omega_1 = 0.045$	$\omega_2 = 0.082$	$\omega_3 = 0.109$
$\omega_4 = 0.127$	$\omega_5 = 0.136$	$\omega_6 = 0.136$
$\omega_7 = 0.127$	$\omega_8 = 0.109$	$\omega_9 = 0.082$
$\omega_{10} = 0.045$		

Residential Sector Final Energy Demand

ENR = COALR + NGR + ELR + OILR

Thermally Adjusted Residential Energy Price

PENR = (0.22 . PCOALR . COALR + 0.7 . PNGR . NGR + 0.95 . PELR . ELR + 0.6 . POILR . OILR)/ENR

D4. IRON/STEEL INDUSTRY SECTOR

Metallurgical Coal Demand

$$MCOAL_t = A_t \cdot e^{-0.005t} \cdot IRN_t$$

D5. ELECTRICITY GENERATION SECTOR

Total Electricity Demand

TEL = ENEL . (ELI + ELR + ELROT)

Demand for Fossil Fuel Generated Electricity

FEL = TEL - HDRGEO - NUC

Energy Inputs for Fossil Generated Electricity

$$FENEL_t = A_0 \cdot e^{-0.003t} \cdot FEL_t$$

Electricity Fuel Shares

Coal Cost Share

$$\frac{COALEL \cdot PCOALEL}{FENEL \cdot PFENEL} = \alpha_C - 0.28 \cdot \omega(L) \cdot \ln\left(\frac{PCOALEL}{POILEL}\right) + 0.0041 \cdot \omega(L) \cdot \ln\left(\frac{PNGEL}{POILEL}\right)$$

Natural Gas Cost Share

$$\frac{NGEL \cdot PNGEL}{FENEL \cdot PFENEL} = \alpha_N + 0.0041 \cdot \omega(L) \cdot \ln\left(\frac{PCOALEL}{POILEL}\right) - 0.0039 \cdot \omega(L) \cdot \ln\left(\frac{PNGEL}{POILEL}\right)$$

Petroleum Cost Share

$$\frac{OILEL \cdot POILEL}{FENEL \cdot PFENEL} = \alpha_0 + 0.27 \cdot \omega(L) \cdot \ln\left(\frac{PCOALEL}{POILEL}\right) - 0.00019 \cdot \omega(L) \cdot \ln\left(\frac{PNGEL}{POILEL}\right)$$

Lag Structure

$\omega_1 = 0.025$	$\omega_1 = 0.045$	$\omega_3 = 0.065$	$\omega_4 = 0.080$
$\omega_5 = 0.090$	$\omega_6 = 0.095$	$\omega_7 = 0.100$	$\omega_8 = 0.110$
$\omega_9 = 0.100$	$\omega_{10} = 0.095$	$\omega_{11} = 0.090$	$\omega_{12} = 0.080$
$\omega_{11} = 0.065$	$\omega_{14} = 0.045$	$\omega_{15} = 0.025$	$\omega_{16} = 0.015$

D6. DEMAND FOR BUNKERS

$$\ln (BUNK) = \beta_0 + \beta_1 \cdot \ln (GDP)$$

Parameter Values	β_1
NOAM	0.30
WEUR	0.40
JANZ	0.40
CSEX	0.50
CDOP	0.40
NOEX	0.40
OIDC	0.35

Fossil Fuel Demand for Electricity Generation

FENEL = COALEL + NGEL + OILEL

Price of Fossil Fuels to Electricity Generation

PFENEL = (PCOALI . COALEL + PNGI . NGEL + POILEL . OILEL)/FENEL

D7. TOTAL PRIMARY ENERGY DEMANDS

Total Thermal Coal Demand

SCOAL = COALI + COALR + COALROT + COALEL + CLF/0.6

Total Primary Coal Demand

TCOAL = ACOAL . (SCOAL + MCOAL)

Total Primary Natural Gas Demand

TNG = ANG . (NGI + NGR + NGEL)

Total Primary Petroleum Demand

TOIL = AOIL . (GAS + DSL + JAK + OILI + OILR + PETROT + OILEL)

SUPPLY BLOCK

S1. EXOGENOUS SUPPLY VARIABLES

DNG, HDRGEO, NUC, SLF, CLF, and DCRUD for non-OPEC regions.

S2. COAL SUPPLY FUNCTION

Long-Run Coal Supply Function

$$CUMSC_t = \left(\frac{PSDC_t}{PSDC_{78}} - 1\right)/ASG \cdot SDC_{78}$$

$$CUMUC_t = \left(\frac{PUDC_t}{PUDC_{78}} - 1\right)/AUG \cdot UDC_{78}$$

$$SDC_t = CUMSC_t - CUMSC_{t-1}$$

$$UDC_t = CUMUC_t - CUMUC_{t-1}$$

Parameter Values

	ASG	AUG
NOAM	0.007	0.010
WEUR	0.012	0.015
JANZ	0.008	0.010
NOEX	0.005	0.011
OIDC	0.005	0.011

Short-Run Coal Supply Function

$$\frac{DCOAL_t}{DCOAL_{t-1}} = \frac{PDCOAL_t}{PDCOAL_{t-1}}, \quad \text{if} \quad \frac{CCAP_t}{TCOAL_t} \leq 0.95$$

Coal Capacity Expansion

$$CCAP_t = A_t \cdot \left(\frac{PDCOAL_{t-3}}{PDCOAL_{t-4}}\right)^{0.05} \cdot \left(\frac{PDCOAL_{t-4}}{PDCOAL_{t-5}}\right)^{0.08} \cdot \left(\frac{PDCOAL_{t-5}}{PDCOAL_{t-6}}\right)^{0.05}$$

Total Coal Production

DCOAL = SDC + UDC

SDC = DCOAL . SPS

Average Price of Coal

PDCOAL = (PSDC . SDC + PUDC . UDC)/DCOAL

PRICE BLOCK

P1. PETROLEUM PRICES

International Petroleum Prices

PCRUDCIF = OPECPRICE + CIFCRUD

Pricing of Domestic Crude

PDCRUD = PCRUDICF . CRUDCT

Average Refinery Acquisition Cost of Crude Oil

REFCRUDCOST = (PDCRUD DCRUD + PCRUDCIF CRUDTARF IMCRUD)/ (DCRUD + IMCRUD)

Ex-Refinery Cost of Petroleum Products

EXREF = REFCRUDCOST + REFMAR

Prices of Petroleum Products

PGAS = DIFGAS . EXREF . GASTAX + DISTGAS

PDSL = DIFDSL . EXREF . DSLTAX + DISTDSL

PJAK = DIFJAK . EXREF . JAKTAX + DISTJAK

PLFO = DIFLFO . EXREF . LFOTAX + DISTLFO

PHFO = DIFHFO . EXREF . HFOTAX + DISTHFO

Industrial Price of Petroleum

POILI = AI . PLFO + (1-AI) . PHFO

Residential Price of Petroleum

POILR = AR . PLFO + (1-AR) PHFO

Price of Petroleum to Thermal Power Sector

POILEL = PHFO

P2. NATURAL GAS PRICES

International Natural Gas Prices

PNGCIF = PCRUDCIF . NGPRT

Pricing of Domestic Natural Gas

PNGWH = PNGCIF . NGCT

Average Supply Price of Natural Gas

PNGA = (PNGCIF . IMNG + PNGWH . DNG)/(IMNG + DNG)

Industrial Price of Natural Gas

PNGI = PNGA + NGTAXI + DISTNGI

Residential Price of Natural Gas

PNGR = PNGA + NGTAXR + DISTNGR

P3. COAL PRICES

International Thermal Coal Prices

PCOALCIF = PCOALFOB + CIFCOAL

Average Supply Price of Thermal Coal

PCOALA = (PCOALCIF . IMCOAL + PDCOAL . DCOAL)/(IMCOAL + DCOAL)

Industrial Price of Steam Coal

PCOALI = PCOALA + COALTAXI + DISTCOALI

Residential Price of Steam Coal

PCOALR = PCOALA + COALTAXR + DISTCOALR

P4. ELECTRICITY PRICES

Cost of Thermal Electricity

FCOST = CCOST + PFENEL

Cost of Hydro/geothermal Electricity

$HCOST = A_0 . e^{0.03t}$

Cost of Nuclear Electricity

$NCOST = A_0 . e^{0.04t}$

Average Cost of Electricity Generation

ELCOST = (FCOST . FEL + HCOST . HDREGO + NCOST . NUC)/TEL

Industrial Price of Electricity

PELI = ELCOST + TDI

Residential Price of Electricity

PELR = ELCOST + TDR

MARKET BLOCK

M1. INTERNATIONAL PETROLEUM MARKET

Non-OPEC Net Imports of Petroleum

IMCRUD = TOIL + BUNK - DCRUD - SLF - CLF - CPECRUD (Regions 1-3 and 6-7).

OPEC Prorationing and Net Exports

EXCRUD = IMCRUD . PRAT (Regions 4-5).

OPEC Production of Petroleum

DCRUD = EXCRUD + TOIL + BUNK - SLF - CLF (Regions 4-5).

M2. INTERNATIONAL NATURAL GAS MARKET

Non-OPEC Net Imports of Natural Gas

IMNG = TNG - DNG - CPENG (Regions 1-3 and 6-7).

OPEC Net Exports of Natural Gas

EXNG = IMNG . (TNG - DNG)/SUM(TNG-DNG) (Regions 4-5).

OPEC Production of Natural Gas

DNG = EXNG + TNG (Regions 4-5).

M3. INTERNATIONAL COAL MARKET

Net Imports of Coal

IMCOAL = TCOAL - DCOAL

Market Clearance Condition

SUM(IMCOAL) - CPECOAL = 0.0

B. LIST OF VARIABLES

- Prices and values in constant 1981 US dollars
- Energy quantities in barrels per day of oil equivalent

Exogenous Variables

POP : Mid-year population in millions.
GDP : Gross domestic product in millions.
GDPI : GDP of the industrial sector in millions.
OPECPRICE : Average price of OPEC crude oil per barrel.
HDRGEO : Supplies of hydro/geothermal electricity.
NUC : Supplies of nuclear electricity.
DCRUD : Supplies of crude oil.
DNG : Supplies of natural gas.
SLF : Supplies of synthetic liquid fuels from heavy oil, tar sands, oil shales, enhanced oil recovery and biomass.
CLF : Supplies of synthetic liquid fuels from coal.
IR : OPEC proven reserves of petroleum in 1978 in billions of barrels.

Endogenous Variables

CAR : Number of passenger cars in stock in millions.
GAS : Demand for gasoline for passenger transportation in millions.
PGAS : Consumer price of gasoline per US gallon.
DSL : Demand for diesel oil for transportation in millions.
PDSL : Consumer price of diesel/gas oil per US gallon.
JAK : Demand for jet kereosene and aviation gasoline in millions.
PJAK : Price of jet fuel kerosene and aviation gasoline per US gallon.
ROT : Demand for energy for rail and other transportation in millions.
PROT : Average end-user price of energy used in the rail and other transportation per million BTUs.
PETROT, COALROT, ELROT: Demand for petroleum, coal and electricity respectively in the rail and other transportation sector in millions.
ENI : Demand for energy in the industrial sector in millions.
PENI : Average end-use price of energy used in the industrial sector per million BUTs.
COALI : Demand for thermal coal in the industrial sector.
PCOALI : Price of thermal coal to the industrial users per million BTUs.
NGI : Demand for natural gas in the industrial sector.

PNGI	:	Price of natural gas to the industrial users per million BTUs.
ELI	:	Demand for electricity in the industrial sector.
PELI	:	Price of electricity to the industrial users per million BTUs.
OILI	:	Demand for petroleum products in the industrial sector.
POILI	:	Average price of petroleum products to the industrial users per million BTUs.
ENR	:	Demand for energy in the residential sector.
PENR	:	Average price of energy to the residential consumers per million BTUs.
COALR	:	Demand for thermal coal in the residential sector.
PCOALR	:	Price of thermal coal to the residential users per million BTUs.
NGR	:	Demand for natural gas in the residential sector.
PNGR	:	Price of natural gas to the residential users per million BTUs.
ELR	:	Demand for electricity in the residential sector.
PELR	:	Price of electricity to the residential users per million BTUs.
OILR	:	Demand for petroleum products in the residential sector.
POILR	:	Average price of petroleum products to the residential sector per million BTUs.
MCOAL	:	Demand for metallurgical coal in the iron and steel industry.
SCOAL	:	Total demand for thermal coal.
TEL	:	Total demand for electricity.
FEL	:	Demand for fossil fuel generated electricity.
FENEL	:	Demand for fossil energy for electricity generation.
PFENEL	:	Average price of fossil energy used for electricity generation per million BTUs.
COALEL	:	Demand for thermal coal for electricity generation.
NGEL	:	Demand for natural gas for electricity generation.
OILEL	:	Demand for petroleum products for electricity generation.
POILEL	:	Average price of petroleum products to the electricity generation sector per million BTUs.
PNGEL	:	Price of natural gas to the electricity generation sector per million BTUs.
PCOALEL	:	Price of thermal coal to the electricity generation sector per million BTUs.
TCOAL	:	Total demand for coal.
TNG	:	Total demand for natural gas.
TOIL	:	Total demand for petroleum.
BUNK	:	Demand for energy (petroleum) for international bunkers.
PCRUDCIF	:	Landed cost of imported crude oil, per barrel.
PCRUD	:	Refiner's acquisition cost of domestically produced crude oil, per barrel.
REFCRUDCOST	:	Refiner's average acquisition cost of imported and domestically produced crude oil, per barrel.
IMCRUD	:	Demand for crude oil imports.
IMCOAL	:	Demand for coal imports.
IMNG	:	Demand for natural gas imports.
EXREF	:	Ex-refinery average cost of petroleum products, per barrel.

PNGCIF : Border price of natural gas imports per million BTUs.
PNGWH : Well-head price of domestically produced natural gas, per million BTUs.
PNGA : Average cost of imported and domestically produced natural gas, per million BTUs.
PCOALFOB: : The export price of thermal coal per metric ton, FOB, US Atlantic ports.
PCOALA : Average cost of domestic and imported thermal coal per metric ton.
DCOAL : Domestic supplies of coal.
CUMSC : Cumulative production of surface-mixed coal.
CUMUC : Cumulative production of underground-mined coal.
SDC : Production of surfaced-mined coal.
UDC : Production of underground-mined coal.
CCPA : Coal production capacity.
PDCOAL : FOB mine price of domestically produced coal.
PSDC : FOB mine price of surface-mined coal.
PUDC : FOB mine price of underground-mined coal.
ELCOST : Average cost of electricity.
FCOST : Cost of thermally generated electricity.
HCOST : Cost of hydro/geothermal electricity.
NCOST : Cost of nuclear electricity.

Constants and Policy Parameters

CRUDCT : Price controls on domestically produced crude oil as a percentage of imported crude oil costs.
REFMAR : Refinery margins per barrel.
CRUDTARF : Tariff on crude oil imports per barrel.
GASTAX, DSLTAX, JAKTAX, LFOTAX, HFOTAX: Domestic consumption taxes on gasoline, diesel oil, jet fuel/kerosene, light fuel oil, heavy fuel oil, respectively per US gallon.
DISTGAS, DISTDSL, DISTJAK, DISTFLO, DISTHFO: Distribution margins on gasoline, diesel oil, jet fuel/kerosine, light fuel oil, heavy fuel oil, respectively per US gallon.
NGPRT : Discount factor on imported natural gas as a percentage of imported crude oil costs, to account for the costs of regasification, etc.
NGCT : Price control on domestically produced natural gas as a percentage of imported natural gas costs.
NGTAXR, NGTAXI: Domestic consumption taxes on natural gas to the residential and the industrial sectors, respectively per million BTUs.
DISTNGR, DISTNGI: Distribution costs of natural gas to the residential and the industrial sectors, respectively per million BTUs.
COALTAXR, COALTAXI: Domestic consumption taxes/subsidies on coal to the residential and the industrial sectors, respectively per million BTUs.
DISTCOALR, DISTCOALI: Distribution costs of coal to the residential and the industrial sectors, respectively per million BTUs.
SDC_{78} : Surface-mined coal production in 1978.
UDC_{78} : Underground-mined coal production in 1978.

SPS	:	The proportion of surface-mined coal.
AI	:	The proportion of light fuel oil in industrial consumption of petroleum products.
AR	:	The proportion of light fuel oil in residential consumption of petroleum products.
TDI, TDR	:	Electricity transmission and distribution costs to industrial and residential sectors, respectively.
A_0	:	Constant coefficient representing the base year relationship.

PRIMARY ENERGY BALANCE : NORTH AMERICA
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	33.16	37.15	35.13	39.29	38.25	37.87	35.83	35.38	35.82	36.83	38.98	42.26
LIQ FUELS	15.17	17.61	17.08	19.73	18.26	16.99	16.09	15.98	16.15	16.45	17.41	17.81
SYNCRUD	0	0	0	0.08	0.10	0.11	0.12	0.13	0.15	0.45	0.87	1.70
COLIQD	0	0	0	0	0	0	0	0	0	0.18	0.46	1.20
NAT.GAS	10.87	11.47	10.20	10.27	9.28	9.14	8.47	8.34	8.10	7.46	7.62	7.46
COAL	6.37	7.07	6.62	7.83	9.27	10.26	9.75	9.51	9.94	10.78	11.34	13.69
SCOAL	5.69	6.37	5.81	6.97	8.57	9.53	8.98	8.71	9.08	9.57	9.58	10.65
METCOAL	0.68	0.70	0.82	0.85	0.70	0.73	0.77	0.80	0.87	0.91	0.98	1.04
PRIM.ELEC	0.75	1.00	1.22	1.46	1.45	1.48	1.52	1.55	1.63	2.14	2.62	3.29
PRODUCTION	31.40	32.51	30.65	31.16	32.84	33.42	32.21	31.42	31.38	33.08	37.19	44.35
PETROLEUM	12.18	12.39	11.26	11.30	11.34	11.09	10.84	10.60	10.14	9.58	9.59	9.60
SYNCRUD	0	0	0	0.08	0.10	0.11	0.12	0.13	0.15	0.45	0.87	1.70
NAT.GAS	11.19	11.88	10.40	10.29	9.28	9.14	8.47	8.34	8.10	7.46	7.62	7.46
COAL	7.28	7.25	7.77	8.02	10.67	11.60	11.26	10.80	11.36	13.45	16.48	22.30
PRIM.ELEC	0.75	1.00	1.22	1.46	1.45	1.48	1.52	1.55	1.63	2.14	2.62	3.29
NUC	0.04	0.18	0.34	0.56	0.52	0.54	0.56	0.59	0.64	1.03	1.47	2.09
NET IMPORTS	2.60	5.11	5.56	8.32	5.84	4.88	4.04	4.39	4.89	4.03	1.81	-2.79
PETROLEUM	3.30	5.72	6.27	8.67	7.25	6.22	5.55	5.68	6.30	6.70	6.96	5.82
NAT.GAS	-0.01	-0.03	-0.02	0.02	0	0	0	0	0	0	0	0
COAL	-0.69	-0.57	-0.69	-0.37	-1.41	-1.34	-1.51	-1.29	-1.41	-2.67	-5.15	-8.61
BUNKERS	0.21	0.41	0.25	0.43	0.43	0.43	0.43	0.43	0.44	0.46	0.48	0.50

SECTORAL ENERGY DEMAND :NORTH AMERICA
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	7.57	8.81	8.96	10.27	10.07	9.79	9.36	9.30	9.66	10.56	11.65	12.48
GASOLINE	5.77	6.69	6.74	7.66	7.51	7.30	6.99	6.92	7.13	7.65	8.22	8.49
DIESEL	0.45	0.64	0.79	1.08	1.09	1.08	1.00	1.03	1.17	1.55	2.03	2.54
JET FUEL	1.04	1.13	1.10	1.15	1.10	1.05	1.00	0.99	1.00	0.99	1.02	1.06
OTH.TRANS	0.32	0.34	0.33	0.38	0.37	0.37	0.36	0.36	0.36	0.36	0.38	0.40
INDUS.ENERGY	8.70	9.64	7.99	9.40	8.61	8.26	7.75	7.61	7.48	7.26	7.63	8.16
PETROLEUM	2.49	3.01	2.72	3.82	3.30	2.95	2.81	2.83	2.80	2.68	2.78	2.74
NAT.GAS	4.10	4.22	3.18	3.09	2.64	2.47	2.26	2.20	2.10	1.90	1.99	2.02
COAL	0.74	0.86	0.81	0.89	0.95	1.01	1.01	0.98	1.01	1.12	1.25	1.60
ELECTRICITY	1.36	1.54	1.29	1.61	1.73	1.83	1.67	1.61	1.57	1.56	1.61	1.80
RESID.ENERGY	9.00	9.74	8.98	9.71	9.33	9.11	8.77	8.75	8.84	8.98	9.35	9.62
PETROLEUM	3.57	3.60	2.92	3.17	2.67	2.23	2.17	2.17	2.13	2.00	1.97	1.75
NAT.GAS	3.70	4.06	3.81	4.04	3.84	3.92	3.75	3.74	3.71	3.60	3.77	3.75
COAL	0.21	0.15	0.10	0.11	0.11	0.10	0.09	0.08	0.07	0.05	0.03	0.02
ELECTRICITY	1.52	1.94	2.15	2.39	2.72	2.86	2.76	2.76	2.92	3.33	3.58	4.10
TOT.ELEC.CON	3.35	4.05	4.24	4.72	5.26	5.55	5.25	5.17	5.32	5.79	6.15	6.99
FOSS.F.ELEC	7.17	8.60	7.99	9.19	10.28	10.93	10.00	9.66	9.79	9.55	9.07	9.38
PETROLEUM	1.04	1.76	1.65	1.88	1.69	1.51	1.28	1.21	1.08	0.72	0.49	0.32
NAT.GAS	1.95	2.03	1.58	1.55	1.51	1.49	1.28	1.24	1.17	0.92	0.80	0.66
COAL	4.19	4.81	4.76	5.65	7.08	7.94	7.44	7.21	7.54	7.91	7.78	8.40

PRIMARY ENERGY BALANCE : WESTERN EUROPE
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	18.22	20.62	19.00	20.68	21.39	20.68	19.98	19.45	19.40	19.44	20.50	22.36
LIQ FUELS	10.88	12.79	11.00	11.88	10.55	9.67	9.32	9.16	8.99	8.60	8.82	8.63
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
COLIQD	0	0	0	0	0	0	0	0	0	0.03	0.08	0.20
NAT.GAS	1.29	2.43	2.95	3.40	3.89	3.68	3.61	3.58	3.63	3.66	3.86	3.98
COAL	5.53	4.81	4.28	4.52	5.97	6.31	5.99	5.64	5.64	5.61	6.06	7.76
SCOAL	4.49	3.82	3.49	3.79	5.23	5.55	5.22	4.84	4.81	4.70	5.04	6.51
METCOAL	1.04	1.00	0.79	0.74	0.74	0.76	0.77	0.79	0.83	0.86	0.89	0.91
PRIM.ELEC	0.52	0.59	0.76	0.88	0.99	1.02	1.04	1.07	1.14	1.57	1.76	1.99
PRODUCTION	6.91	7.41	7.93	9.35	10.76	11.28	11.23	11.32	11.94	11.23	10.03	9.30
PETROLEUM	0.40	0.33	0.45	1.68	2.36	2.52	2.70	2.89	3.30	2.76	2.63	2.50
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	1.26	2.33	2.74	3.00	3.19	3.18	3.17	3.17	3.15	2.88	2.63	2.40
COAL	4.74	4.16	3.98	3.78	4.23	4.56	4.31	4.20	4.35	4.01	3.00	2.41
PRIM.ELEC	0.52	0.59	0.76	0.88	0.99	1.02	1.04	1.07	1.14	1.57	1.76	1.99
NUC	0.03	0.07	0.18	0.28	0.36	0.38	0.39	0.41	0.44	0.83	1.00	1.21
NET IMPORTS	13.00	14.96	11.94	11.85	11.29	10.06	9.41	8.79	8.13	8.89	11.15	13.65
PETROLEUM	12.24	14.23	11.00	10.72	8.85	7.81	7.29	6.94	6.37	6.52	6.86	6.72
NAT.GAS	0.04	0.11	0.24	0.46	0.70	0.50	0.44	0.41	0.48	0.77	1.23	1.58
COAL	0.71	0.61	0.70	0.67	1.74	1.75	1.68	1.44	1.29	1.60	3.05	5.35
BUNKERS	0.45	0.57	0.64	0.65	0.66	0.66	0.66	0.66	0.67	0.71	0.75	0.79

SECTORAL ENERGY DEMAND :WESTERN EUROPE
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	2.49	2.93	2.92	3.32	3.26	3.11	3.04	3.00	3.08	3.32	3.64	3.85
GASOLINE	1.37	1.66	1.75	1.95	1.90	1.81	1.76	1.72	1.75	1.85	1.98	2.04
DIESEL	0.59	0.71	0.63	0.81	0.80	0.75	0.74	0.74	0.79	0.92	1.07	1.19
JET FUEL	0.25	0.30	0.28	0.33	0.33	0.32	0.31	0.31	0.32	0.33	0.36	0.39
OTH.TRANS	0.28	0.27	0.25	0.23	0.23	0.23	0.23	0.22	0.22	0.22	0.23	0.24
INDUS.ENERGY	5.76	6.66	5.79	6.05	5.91	5.58	5.43	5.32	5.23	5.02	5.14	5.35
PETROLEUM	3.73	4.22	3.27	3.29	2.80	2.57	2.52	2.52	2.47	2.28	2.28	2.15
NAT.GAS	0.58	1.04	1.20	1.30	1.39	1.26	1.23	1.21	1.21	1.16	1.20	1.18
COAL	0.62	0.43	0.38	0.38	0.49	0.51	0.51	0.50	0.50	0.52	0.60	0.81
ELECTRICITY	0.83	0.97	0.94	1.04	1.24	1.25	1.17	1.10	1.06	1.05	1.07	1.21
RESID.ENERGY	5.12	5.85	5.71	6.32	6.24	5.93	5.81	5.73	5.76	5.99	6.37	6.75
PETROLEUM	2.74	3.31	3.08	3.27	2.60	2.29	2.24	2.22	2.18	2.09	2.12	1.96
NAT.GAS	0.55	0.89	1.10	1.42	1.74	1.72	1.75	1.77	1.85	2.03	2.24	2.40
COAL	1.17	0.79	0.64	0.54	0.57	0.53	0.48	0.42	0.35	0.25	0.18	0.15
ELECTRICITY	0.66	0.85	0.90	1.08	1.33	1.39	1.35	1.32	1.38	1.62	1.82	2.25
TOT.ELEC.CON	1.83	2.20	2.23	2.55	3.07	3.16	3.02	2.90	2.92	3.20	3.47	4.13
FOSS.F.ELEC	3.61	4.31	3.91	4.42	5.63	5.78	5.29	4.88	4.75	4.27	4.39	5.43
PETROLEUM	1.16	1.56	1.20	1.35	1.19	1.08	0.92	0.83	0.69	0.35	0.21	0.11
NAT.GAS	0.25	0.50	0.62	0.61	0.72	0.67	0.60	0.56	0.53	0.42	0.39	0.36
COAL	2.20	2.26	2.09	2.56	3.72	4.03	3.77	3.49	3.53	3.50	3.79	4.97

PRIMARY ENERGY BALANCE : JAPAN/AUS/NZ
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	6.44	7.68	7.64	8.37	9.22	9.17	9.06	9.04	9.20	9.40	10.10	11.20
LIQ FUELS	4.43	5.69	5.39	5.95	5.90	5.58	5.44	5.43	5.40	5.09	5.21	5.15
SYNCRUD	0	0	0	0	0	0	0	0	0	0.08	0.15	0.30
COLIQD	0	0	0	0	0	0	0	0	0	0.07	0.14	0.30
NAT.GAS	0.10	0.19	0.26	0.47	0.52	0.55	0.53	0.53	0.54	0.55	0.57	0.60
COAL	1.73	1.62	1.74	1.66	2.44	2.68	2.73	2.72	2.88	3.15	3.51	4.31
SCOAL	1.11	0.88	1.10	1.09	1.81	2.05	2.10	2.08	2.24	2.36	2.56	3.09
METCOAL	0.63	0.73	0.64	0.57	0.62	0.63	0.63	0.64	0.65	0.67	0.70	0.73
PRIM.ELEC	0.18	0.19	0.25	0.29	0.36	0.36	0.36	0.37	0.37	0.60	0.81	1.14
PRODUCTION	1.74	1.86	2.05	2.40	2.62	2.82	2.85	2.86	3.15	3.67	4.80	6.82
PETROLEUM	0.19	0.41	0.43	0.49	0.46	0.45	0.45	0.44	0.43	0.50	0.70	0.98
SYNCRUD	0	0	0	0	0	0	0	0	0	0.08	0.15	0.30
NAT.GAS	0.07	0.12	0.14	0.20	0.21	0.25	0.31	0.37	0.54	0.55	0.57	0.60
COAL	1.30	1.14	1.23	1.42	1.59	1.75	1.73	1.67	1.80	1.93	2.57	3.79
PRIM.ELEC	0.18	0.19	0.25	0.29	0.36	0.36	0.36	0.37	0.37	0.60	0.81	1.14
NUC	0.01	0.02	0.04	0.10	0.14	0.14	0.14	0.13	0.13	0.30	0.48	0.78
NET IMPORTS	5.12	6.35	5.98	6.19	6.82	6.57	6.43	6.41	6.28	5.91	5.42	4.38
PETROLEUM	4.58	5.80	5.33	5.66	5.66	5.34	5.21	5.21	5.20	4.69	4.48	3.86
NAT.GAS	0.03	0.06	0.12	0.27	0.31	0.30	0.22	0.15	0	0	0	0
COAL	0.52	0.49	0.53	0.26	0.84	0.93	1.00	1.05	1.08	1.22	0.94	0.52
BUNKERS	0.19	0.37	0.36	0.21	0.22	0.22	0.22	0.23	0.23	0.25	0.27	0.29

SECTORAL ENERGY DEMAND :JAPAN/AUS/NZ
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	0.89	1.09	1.17	1.50	1.55	1.54	1.54	1.55	1.61	1.76	1.96	2.12
GASOLINE	0.52	0.65	0.71	0.93	0.96	0.95	0.95	0.95	0.99	1.08	1.19	1.27
DIESEL	0.15	0.19	0.15	0.17	0.18	0.18	0.18	0.18	0.20	0.23	0.27	0.30
JET FUEL	0.05	0.06	0.10	0.11	0.12	0.12	0.12	0.13	0.14	0.16	0.19	0.22
OTH.TRANS	0.17	0.18	0.22	0.28	0.29	0.29	0.29	0.29	0.29	0.30	0.32	0.34
INDUS.ENERGY	2.28	2.95	2.38	3.04	3.17	3.08	3.05	3.06	3.07	3.10	3.38	3.76
PETROLEUM	1.67	2.20	1.61	2.14	2.01	1.86	1.85	1.89	1.90	1.80	1.90	1.90
NAT.GAS	0.03	0.07	0.08	0.12	0.15	0.17	0.17	0.18	0.20	0.22	0.26	0.30
COAL	0.14	0.11	0.15	0.16	0.22	0.23	0.24	0.22	0.20	0.23	0.30	0.45
ELECTRICITY	0.44	0.56	0.55	0.62	0.79	0.82	0.79	0.77	0.78	0.84	0.93	1.11
RESID.ENERGY	1.08	1.43	1.37	1.40	1.38	1.34	1.32	1.32	1.33	1.34	1.40	1.51
PETROLEUM	0.76	1.03	0.85	0.81	0.68	0.62	0.62	0.62	0.61	0.54	0.54	0.48
NAT.GAS	0.09	0.12	0.14	0.15	0.17	0.17	0.17	0.17	0.18	0.21	0.23	0.26
COAL	0.07	0.05	0.10	0.08	0.09	0.08	0.07	0.07	0.06	0.04	0.03	0.02
ELECTRICITY	0.17	0.24	0.28	0.35	0.44	0.46	0.46	0.46	0.48	0.55	0.61	0.74
TOT.ELEC.CON	0.73	0.94	0.98	1.15	1.45	1.50	1.46	1.45	1.48	1.63	1.80	2.16
FOSS.F.ELEC	1.33	1.76	2.12	2.10	2.76	2.87	2.77	2.71	2.78	2.52	2.40	2.43
PETROLEUM	0.76	1.24	1.44	1.25	1.35	1.26	1.15	1.09	1.00	0.72	0.54	0.38
NAT.GAS	0.03	0.06	0.11	0.24	0.30	0.32	0.29	0.28	0.27	0.23	0.20	0.16
COAL	0.55	0.46	0.58	0.66	1.10	1.29	1.33	1.34	1.50	1.57	1.66	1.89

PRIMARY ENERGY BALANCE : CAP-SURP OIL-EXP
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	0.73	0.94	1.18	1.63	1.57	1.34	1.32	1.38	1.56	2.11	2.74	3.57
LIQ FUELS	0.45	0.61	0.79	1.25	1.24	1.05	1.03	1.09	1.25	1.72	2.23	2.94
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
COLIQD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	0.27	0.31	0.37	0.36	0.31	0.27	0.26	0.27	0.29	0.34	0.44	0.54
COAL	0.01	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.05
SCOAL	0.01	0.01	0.01	0.01	0	0	0	0	0	0	0.01	0.02
METCOAL	0	0	0	0	0	0	0	0	0	0.02	0.02	0.03
PRIM.ELEC	0	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04
PRODUCTION	17.15	23.58	21.36	23.58	21.11	18.41	16.81	16.49	16.40	16.94	19.50	20.15
PETROLEUM	16.85	23.04	20.75	22.97	20.15	17.60	16.11	15.85	15.88	16.26	18.50	18.89
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	0.29	0.52	0.59	0.59	0.93	0.78	0.68	0.61	0.49	0.63	0.96	1.21
COAL	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01	0.02	0.01	0.01	0.01
PRIM.ELEC	0	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04
NUC	0	0	0	0	0	0	0	0	0	0.02	0.02	0.02
NET IMPORTS	-15.97	-22.09	-19.70	-21.53	-19.17	-16.72	-15.15	-14.75	-14.47	-14.40	-16.28	-16.04
PETROLEUM	-15.95	-21.88	-19.49	-21.30	-18.54	-16.19	-14.73	-14.41	-14.26	-14.12	-15.79	-15.41
NAT.GAS	-0.02	-0.21	-0.22	-0.23	-0.62	-0.52	-0.41	-0.33	-0.20	-0.29	-0.51	-0.67
COAL	0	0	0	0	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.02	0.03
BUNKERS	0.44	0.52	0.32	0.36	0.37	0.35	0.35	0.35	0.37	0.42	0.48	0.54

SECTORAL ENERGY DEMAND :CAP-SURP OIL-EXP
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	0.08	0.13	0.18	0.24	0.25	0.20	0.20	0.20	0.22	0.27	0.33	0.41
GASOLINE	0.06	0.09	0.12	0.14	0.15	0.12	0.12	0.12	0.13	0.15	0.19	0.23
DIESEL	0	0.01	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.03	0.04	0.06
JET FUEL	0.01	0.03	0.05	0.07	0.07	0.06	0.05	0.06	0.06	0.08	0.09	0.11
OTH.TRANS	0	0	0	0	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
INDUS.ENERGY	0.52	0.63	0.75	0.93	0.83	0.71	0.70	0.73	0.82	1.10	1.43	1.85
PETROLEUM	0.27	0.36	0.43	0.62	0.56	0.48	0.47	0.49	0.57	0.81	1.05	1.38
NAT.GAS	0.23	0.25	0.29	0.29	0.25	0.21	0.21	0.22	0.23	0.25	0.32	0.38
COAL	0.01	0.01	0.01	0.01	0	0	0	0	0	0.01	0.01	0.02
ELECTRICITY	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.06
RESID.ENERGY	0.08	0.11	0.14	0.25	0.29	0.25	0.25	0.27	0.30	0.41	0.52	0.65
PETROLEUM	0.06	0.08	0.11	0.22	0.25	0.22	0.21	0.22	0.25	0.31	0.38	0.44
NAT.GAS	0	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.04	0.06
COAL	0	0	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.07	0.10	0.15
TOT.ELEC.CON	0.02	0.03	0.04	0.06	0.06	0.05	0.05	0.06	0.07	0.12	0.17	0.25
FOSS.F.ELEC	0.04	0.08	0.11	0.16	0.12	0.10	0.10	0.11	0.15	0.24	0.35	0.55
PETROLEUM	0.04	0.06	0.07	0.14	0.10	0.09	0.09	0.10	0.14	0.22	0.33	0.52
NAT.GAS	0	0.02	0.04	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.03	0.04
COAL	0	0	0	0	0	0	0	0	0	-0.01	-0.01	-0.01

PRIMARY ENERGY BALANCE : CAP-DEF OPEC
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	0.83	1.05	1.15	1.41	1.60	1.63	1.63	1.71	1.89	2.38	2.88	3.51
LIQ FUELS	0.59	0.71	0.78	0.98	1.08	1.06	1.03	1.06	1.15	1.35	1.56	1.85
SYNCRUD	0	0	0	0	0	0	0	0	0	0.10	0.22	0.50
COLIQD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	0.21	0.30	0.33	0.39	0.45	0.50	0.51	0.55	0.63	0.83	1.05	1.28
COAL	0.01	0.02	0.01	0.01	0.03	0.03	0.04	0.04	0.05	0.13	0.19	0.28
SCOAL	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.05	0.08	0.14
METCOAL	0	0.01	0	0	0.02	0.02	0.03	0.03	0.03	0.07	0.11	0.14
PRIM.ELEC	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.05	0.06	0.07	0.08	0.09
PRODUCTION	7.18	8.71	7.28	8.03	7.19	6.52	6.07	6.03	6.14	6.66	7.77	8.38
PETROLEUM	6.93	8.33	6.85	7.40	6.35	5.67	5.23	5.17	5.22	5.28	5.85	5.75
SYNCRUD	0	0	0	0	0	0	0	0	0	0.10	0.22	0.50
NAT.GAS	0.23	0.35	0.40	0.59	0.77	0.77	0.74	0.75	0.76	1.02	1.37	1.70
COAL	0	0.01	0.01	0.01	0.03	0.04	0.05	0.06	0.11	0.19	0.25	0.33
PRIM.ELEC	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.05	0.06	0.07	0.08	0.09
NUC	0	0	0	0	0	0	0	0	0	0	0	0
NET IMPORTS	-6.21	-7.66	-6.12	-6.69	-5.55	-4.85	-4.40	-4.28	-4.21	-4.23	-4.83	-4.81
PETROLEUM	-6.19	-7.62	-6.06	-6.49	-5.23	-4.57	-4.15	-4.06	-4.02	-3.98	-4.45	-4.35
NAT.GAS	-0.03	-0.05	-0.07	-0.21	-0.32	-0.27	-0.23	-0.19	-0.13	-0.18	-0.32	-0.42
COAL	0.01	0.01	0.01	0.01	0	-0.01	-0.01	-0.02	-0.06	-0.07	-0.06	-0.05
BUNKERS	0.07	0.07	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.06

SECTORAL ENERGY DEMAND :CAP-DEF OPEC
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	0.21	0.28	0.30	0.30	0.33	0.33	0.33	0.34	0.36	0.42	0.50	0.59
GASOLINE	0.17	0.23	0.23	0.23	0.24	0.24	0.24	0.25	0.26	0.30	0.35	0.41
DIESEL	0.01	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.09
JET FUEL	0.02	0.02	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.06	0.07	0.08
OTH.TRANS	0	0	0	0	0	0	0	0	0	0	0	0
INDUS.ENERGY	0.36	0.43	0.47	0.64	0.71	0.73	0.74	0.78	0.87	1.11	1.36	1.65
PETROLEUM	0.20	0.20	0.25	0.39	0.43	0.42	0.42	0.43	0.48	0.59	0.71	0.85
NAT.GAS	0.14	0.21	0.20	0.23	0.25	0.28	0.29	0.31	0.35	0.45	0.58	0.70
COAL	0	0	0	0	0	0	0	0.01	0.01	0.02	0.02	0.04
ELECTRICITY	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.05	0.05	0.06
RESID.ENERGY	0.14	0.18	0.20	0.25	0.27	0.27	0.27	0.28	0.30	0.34	0.40	0.46
PETROLEUM	0.11	0.13	0.13	0.16	0.16	0.15	0.14	0.14	0.14	0.13	0.13	0.13
NAT.GAS	0.02	0.03	0.05	0.06	0.07	0.08	0.08	0.09	0.10	0.14	0.18	0.20
COAL	0	0	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.05	0.06	0.08	0.10	0.13
TOT.ELEC.CON	0.03	0.04	0.05	0.07	0.08	0.08	0.08	0.09	0.11	0.15	0.17	0.23
FOSS.F.ELEC	0.04	0.07	0.08	0.10	0.11	0.12	0.11	0.11	0.13	0.21	0.24	0.35
PETROLEUM	0.02	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.09
NAT.GAS	0.01	0.02	0.03	0.05	0.05	0.06	0.06	0.06	0.07	0.11	0.12	0.17
COAL	0	0	0	0	0	0	0	0	0.01	0.03	0.05	0.09

PRIMARY ENERGY BALANCE : NON-OPEC OIL-EXP
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	1.18	1.46	1.62	2.18	2.57	2.81	2.77	2.87	3.16	4.07	5.15	6.53
LIQ FUELS	0.84	1.03	1.15	1.54	1.89	2.05	1.99	2.06	2.26	2.84	3.48	4.34
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
COLIQD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	0.25	0.33	0.34	0.48	0.53	0.60	0.60	0.63	0.69	0.89	1.18	1.46
COAL	0.05	0.06	0.08	0.09	0.06	0.07	0.08	0.09	0.11	0.20	0.34	0.56
SCOAL	0.03	0.04	0.06	0.06	0.03	0.04	0.04	0.04	0.05	0.10	0.18	0.36
METCOAL	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.05	0.06	0.10	0.15	0.21
PRIM.ELEC	0.04	0.05	0.05	0.07	0.08	0.09	0.09	0.10	0.11	0.14	0.15	0.17
PRODUCTION	1.80	2.14	2.68	3.89	5.19	5.53	5.84	6.18	6.94	8.63	9.57	10.58
PETROLEUM	1.47	1.68	2.13	3.11	4.40	4.68	4.98	5.30	6.00	7.40	7.93	8.50
SYNCRUD	0	0	0	0	0	0	0	0	0	0	0	0
NAT.GAS	0.26	0.37	0.45	0.64	0.63	0.68	0.68	0.71	0.75	0.99	1.36	1.73
COAL	0.03	0.04	0.05	0.07	0.07	0.08	0.08	0.08	0.09	0.10	0.13	0.18
PRIM.ELEC	0.04	0.05	0.05	0.07	0.08	0.09	0.09	0.10	0.11	0.14	0.15	0.17
NUC	0	0	0	0	0	0	0	0	0	0.01	0.02	0.02
NET IMPORTS	-0.55	-0.54	-0.92	-1.39	-2.57	-2.67	-3.02	-3.25	-3.72	-4.49	-4.35	-3.97
PETROLEUM	-0.55	-0.52	-0.84	-1.26	-2.46	-2.57	-2.93	-3.19	-3.68	-4.50	-4.38	-4.08
NAT.GAS	-0.02	-0.04	-0.11	-0.15	-0.10	-0.09	-0.08	-0.07	-0.06	-0.09	-0.18	-0.27
COAL	0.02	0.01	0.03	0.02	-0.01	-0.01	0	0.01	0.02	0.10	0.21	0.38
BUNKERS	0.07	0.07	0.06	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.08

SECTORAL ENERGY DEMAND :NON-OPEC OIL-EXP
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	0.31	0.39	0.39	0.54	0.63	0.68	0.67	0.68	0.72	0.84	1.04	1.26
GASOLINE	0.20	0.26	0.29	0.34	0.39	0.42	0.41	0.41	0.43	0.47	0.56	0.66
DIESEL	0.08	0.09	0.06	0.14	0.18	0.19	0.19	0.20	0.21	0.27	0.36	0.47
JET FUEL	0.02	0.02	0.02	0.04	0.04	0.05	0.05	0.05	0.06	0.07	0.09	0.12
OTH.TRANS	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
INDUS.ENERGY	0.48	0.60	0.69	0.97	1.18	1.28	1.27	1.33	1.47	1.89	2.40	3.02
PETROLEUM	0.25	0.30	0.36	0.52	0.68	0.72	0.70	0.72	0.80	1.01	1.27	1.59
NAT.GAS	0.17	0.23	0.24	0.35	0.39	0.43	0.44	0.46	0.50	0.62	0.80	0.97
COAL	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.08	0.10	0.16
ELECTRICITY	0.04	0.06	0.07	0.07	0.09	0.10	0.10	0.11	0.13	0.19	0.22	0.31
RESID.ENERGY	0.15	0.18	0.18	0.23	0.28	0.30	0.29	0.30	0.33	0.39	0.48	0.57
PETROLEUM	0.11	0.13	0.13	0.16	0.20	0.21	0.21	0.22	0.23	0.24	0.26	0.27
NAT.GAS	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0	0.02	0.04	0.06
COAL	0	0	0	0	0	0	0	0	0	0	0	0
ELECTRICITY	0.03	0.04	0.04	0.06	0.06	0.07	0.07	0.08	0.09	0.14	0.18	0.24
TOT.ELEC.CON	0.09	0.11	0.13	0.15	0.17	0.19	0.19	0.21	0.25	0.37	0.46	0.62
FOSS.F.ELEC	0.11	0.15	0.20	0.22	0.24	0.30	0.28	0.31	0.37	0.61	0.79	1.16
PETROLEUM	0.08	0.12	0.16	0.18	0.20	0.24	0.23	0.25	0.30	0.48	0.59	0.81
NAT.GAS	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.06	0.07	0.11	0.14	0.19
COAL	0	0	0	0	0	0	0	0	0	0.02	0.06	0.17

PRIMARY ENERGY BALANCE : OIL-IMP LDCS
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
CONSUMPTION	7.16	9.28	9.79	11.62	12.03	11.94	11.83	11.98	12.82	15.48	19.19	23.70
LIQ FUELS	4.33	6.05	6.19	7.46	7.00	6.48	6.29	6.37	6.68	7.71	9.49	11.00
SYNCRUD	0	0	0	0	0	0	0	0	0	0.05	0.12	0.30
COLIQD	0	0	0	0.01	0.01	0.03	0.04	0.06	0.10	0.15	0.19	0.25
NAT.GAS	0.24	0.36	0.41	0.47	0.87	0.98	1.04	1.10	1.16	1.34	1.76	2.27
COAL	2.29	2.49	2.75	3.09	3.51	3.76	3.73	3.67	3.99	4.95	6.06	7.92
SCOAL	1.95	2.10	2.34	2.62	2.92	3.11	3.02	2.91	3.11	3.65	4.21	5.29
METCOAL	0.35	0.38	0.42	0.46	0.59	0.61	0.64	0.66	0.71	1.06	1.53	2.22
PRIM.ELEC	0.30	0.38	0.44	0.60	0.65	0.71	0.77	0.84	0.99	1.48	1.87	2.50
PRODUCTION	4.02	4.36	4.78	5.34	7.00	7.57	7.67	7.77	8.56	10.23	11.24	13.18
PETROLEUM	1.23	1.29	1.27	1.25	1.70	1.77	1.85	1.93	2.10	2.80	3.13	3.50
SYNCRUD	0	0	0	0	0	0	0	0	0	0.05	0.12	0.30
NAT.GAS	0.28	0.36	0.41	0.46	0.72	0.79	0.85	0.93	1.10	1.34	1.70	2.10
COAL	2.20	2.34	2.66	3.03	3.92	4.30	4.20	4.08	4.37	4.57	4.42	4.77
PRIM.ELEC	0.30	0.38	0.44	0.60	0.65	0.71	0.77	0.84	0.99	1.48	1.87	2.50
NUC	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.06	0.09	0.29	0.55	1.02
NET IMPORTS	3.86	5.72	5.65	7.10	5.62	4.93	4.71	4.75	4.78	5.77	8.48	11.06
PETROLEUM	3.80	5.59	5.50	7.01	5.88	5.27	4.99	4.98	5.09	5.38	6.77	7.74
NAT.GAS	-0.04	0	0	0.01	0.15	0.20	0.19	0.17	0.06	0	0.06	0.17
COAL	0.11	0.13	0.15	0.07	-0.41	-0.54	-0.47	-0.40	-0.38	0.39	1.65	3.15
BUNKERS	0.60	0.67	0.55	0.57	0.59	0.59	0.59	0.60	0.62	0.67	0.73	0.79

SECTORAL ENERGY DEMAND :OIL-IMP LDCS
UNIT : MBDOE

	1970	1973	1975	1978	1980	1981	1982	1983	1985	1990	1995	2000
TRANS.FUEL	1.76	2.23	2.33	2.59	2.59	2.50	2.49	2.52	2.70	3.23	4.00	4.82
GASOLINE	0.92	1.11	1.15	1.26	1.24	1.19	1.18	1.18	1.26	1.51	1.85	2.20
DIESEL	0.24	0.40	0.45	0.55	0.56	0.54	0.54	0.56	0.63	0.84	1.11	1.42
JET FUEL	0.16	0.25	0.25	0.29	0.28	0.27	0.27	0.27	0.28	0.31	0.37	0.45
OTH.TRANS	0.45	0.47	0.48	0.49	0.50	0.50	0.50	0.51	0.53	0.58	0.66	0.75
INDUS.ENERGY	2.40	3.26	3.32	4.00	4.21	4.17	4.21	4.32	4.67	5.78	7.34	9.29
PETROLEUM	1.41	2.06	2.03	2.52	2.26	2.08	2.08	2.17	2.33	2.83	3.62	4.25
NAT.GAS	0.14	0.21	0.24	0.25	0.44	0.51	0.55	0.59	0.63	0.74	1.00	1.31
COAL	0.51	0.54	0.53	0.58	0.77	0.82	0.85	0.85	0.94	1.26	1.62	2.38
ELECTRICITY	0.34	0.45	0.52	0.64	0.74	0.76	0.73	0.71	0.76	0.94	1.11	1.35
RESID.ENERGY	1.17	1.50	1.68	2.03	2.03	1.99	2.00	2.05	2.18	2.55	2.99	3.51
PETROLEUM	0.67	0.89	0.87	1.05	0.80	0.69	0.69	0.71	0.75	0.84	0.98	1.03
NAT.GAS	0.04	0.05	0.06	0.09	0.21	0.25	0.27	0.29	0.31	0.38	0.48	0.62
COAL	0.23	0.24	0.41	0.47	0.51	0.50	0.49	0.48	0.47	0.48	0.46	0.48
ELECTRICITY	0.23	0.31	0.34	0.42	0.52	0.55	0.55	0.56	0.64	0.86	1.06	1.38
TOT.ELEC.CON	0.69	0.92	1.05	1.31	1.55	1.61	1.57	1.57	1.73	2.21	2.65	3.32
FOSS.F.ELEC	1.05	1.42	1.59	1.78	2.36	2.38	2.10	1.91	1.91	1.87	1.97	2.03
PETROLEUM	0.52	0.76	0.87	0.91	0.92	0.81	0.66	0.58	0.49	0.33	0.30	0.22
NAT.GAS	0.03	0.06	0.07	0.08	0.11	0.10	0.08	0.07	0.07	0.05	0.05	0.04
COAL	0.50	0.60	0.65	0.80	1.33	1.46	1.35	1.26	1.36	1.49	1.62	1.77

REFERENCES

1. Adelman, M.A., and H.D. Jacoby (1977), "Alternative Methods of Oil Supply Forecasting," MIT Energy Laboratory Working Paper No. MIT-EL 77-023WP, Cambridge, Massachusetts, August.

2. Adelman, M.A., and J.L. Paddock (1980), "An Aggregate Model of Petroleum Production Capacity and Supply Forecasting," MIT Energy Laboratory Working Paper No. MIT-EL79-005WP, Cambridge, Mass.

3. Adelman, M.A., and G.L. Ward (1980), "Worldwide Production Costs of Oil and Gas," MIT Energy Laboratory Working Paper No. MIT-EL79-058WP, Cambridge, Mass.

4. Adams, F.G., H. Graham, and J. M. Griffin (1974), "Demand Elasticities for Gasoline: Another View," Discussion Paper No. 279, Department of Economics, University of Pennsylvania, June.

5. Almon, Shirley (1965), "The Distributed Lag Between Capital Appropriations and Expenditures," Econometrica, vol. 33, No. 1 (January), pp. 178-196.

6. Baughman, M., and P. Joskow (1975), "Energy Consumption and Fuel Choice by Residential and Commercial Consumers in the United States," MIT Energy Laboratory Report No. MIT-EL75-024, Cambridge, Mass.

7. Atkinson, S., and R. Halvorsen (1976), "Interfuel Substitution in Steam Electric Power Generation," Journal of Political Economy, Vol. 84, No. 5, pp. 959-978.

8. Berndt, E.R., M.A. Fuss, and L. Waverman (1977), "Dynamic Models of the Industrial Demand for Energy," Electric Power Research Institute, Technical Report No. EA-580, November, Palo Alto, Calif.

9. Berndt, E.R., C.J. Morrison, and G.C. Watkins (1981), "Dynamic Models of Energy Demand: An Assessment and Comparison," in Modeling and Measuring Natural Resource Substitution (Amsterdam: North Holland).

10. Berndt, E.R., and D.O. Wood (1975), "Technology, Prices, and the Derived Demand for Energy," Review of Economics and Statistics, 57 (August), pp. 259-268.

11. Berndt, E.R., and D.O. Wood (1979), "Engineering and Econometric Interpretations of Energy-Capital Complimentarity," American Economic Review, 69 (June), pp. 342-354.

12. Blitzer, C., A. Meeraus, and A. Stoutjesdijk (1975), "A Dynamic Model of OPEC Trade and Production," Journal of Development Economics, Vol. 2, No. 4, pp. 319-335.

13. Bohi, D.R. (1981), Analyzing Demand Behavior: A Study of Energy Elasticities, Published for Resources for the Future (Baltimore: The Johns Hopkins University Press).

14. Burright, B.K., and J.H. Euns (1975), "Econometric Models of the Demand for Motor Fuel," Report R-1561-NSF/FEA (Santa Monica, Calif.: Rand Corp.).

15. Chamberlain, C., (1973), "Models of Gasoline Demand," Report No. PRSP-21, Transportation Systems Center, Cambridge, Mass.

16. Charles River Associates (1977), "Regional Coal Price Forecasting Model," a paper presented at the May 1977 Meeting of the Operations REsearch Society of America and the Institute of Management Sciences.

17. Choe, B.J. (1978), "Energy Demand Prospects in Non-OPEC Developing Countries," in Workshops on Energy Supply and Demand (Paris: IEA/OECD), pp. 422-440.

18. Choe, B.J. (1980), "Energy Demand in Developing Countries," in International Energy Strategies, ed. Joy Dunkerley (Cambridge: Oelgeschlager, Gun & Hain), pp. 223-233.

19. Cramer, J., and D. Salehi (1980), "A Theory of Competitive Pricing in the Oil Market: What Does OPEC Really Do?," Working Paper No. 80-4, Center for Analytical Research in Economics in Social Sciences, University of Pennsylvania.

20. Cremer, J., and M.L. Weitzman, "OPEC and the Monopoly Price of World Oil," European Economic Review, Vol. 8, August, pp. 155-164.

21. Darmstadter, J., J. Dunkerley, and J. Alterman (1977), How Industrial Societies Use Energy (Baltimore: Johns Hopkins University Press).

22. Dasgupta, P.S., and G.M. Heal (1979), Economic Theory and Exhaustible Resources (Cambridge: Cambridge University Press).

23. Eckbo, P.L., H.D. Jacoby, and J.L. Smith (1978), "Oil Supply Forecasting: A Disaggregated Process Approach," The Bell Journal of Economics, Vol. 9, pp.218-238.

24. Energy Modeling Forum (1978), "Coal in Transition: 1980-2000," EMF Report 2, Volumes 1 and 2, Stanford University, Stanford, California.

25. Energy Modeling Forum (1980), Aggregate Elasticity of Energy Demand, Vol.1, EMF Report 4, Stanford University, Stanford, California.

26. Energy Modeling Forum (1982), World Oil, Summary Report, EMF Report No. 6, Stanford University, Stanford, California.

27. Epstein, L.G. and M. Denny (1980), "The Multivariate Flexible Accelerator Model: Its Empirical Restrictions and an Application to U.S. Manufacturing," Working Peper 8003, Institute for Policy Analysis, University of Toronto.

28. Fisher, D., D. Gately, and J.F. Kyle (1975), "Prospects for OPEC: A Critical Survey of Models of the World Energy Market," Journal of Development Economics, Vol. 2, pp. 363-386.

29. Fisher, F.M. (1974), Supply and Cost in the U.S. Petroleum Industry: Two Econometric Studies (Baltimore: The Johns Hopkins Press).

30. Fuss, M.A. (1977), "The Demand for Energy in Canadian Manufacturing," Journal of Econometrics, 5, pp. 89-116.

31. Fuss, M., R. Hyndman, and L. Waverman (1975), "Residential, Commercial and Industrial Demand for Energy in Canada: Projections to 1985 with Three Alternative Models," in W.D. Nordhus ed. Proceedings of the Workshop on Energy Demand (Laxenburg, Austria: International Institute for Applied Systems Analysis).

32. Gately, D., J.F. Kyle, and D. Fisher (1977), "Strategies for OPEC's Pricing Decisions," European Economic Review, Vol. 10, pp. 209-218.

33. Gordon, R.L. (1975), U.S. Coal and the Electric Power Industry (Baltimore: The Johns Hopkins University Press).

34. Gordon, R.L. (1978), Coal in the U.S. Energy Market (Lexington, Mass.: D.C. Heath and Company).

35. Griffin, J.M. (1979), Energy Conservation in the OECD, 1980-2000 (Cambridge, Massachusetts: Ballinger Publishing Company).

36. Griffin, J.M., and P.R. Gregory (1976), "An Intercountry Translog Model of Energy Substitution Responses," American Economic Review, 66 (December), pp. 845-857.

37. Halvorsen, R. (1975), "Energy Substitution in U.S. Manufacturing," a paper presented at the winter meeting of the Econometric Society, December.

38. Halvorsen, R., and J. Ford (1978), "Substitution Among Energy, Capital, and Labor Inputs in U.S. Manufacturing," in R. S. Pindyck ed. Advances in the Economics of Energy and Resources, (Greenwich, Conn.: J.A.I. Press).

39. Heal, G. (1976), "The Relationship Between Price and Extraction Cost for a Resource with a Backstop Technology," Bell Journal of Economics, Vol. 7(2), pp. 371-8.

40. Halvorsen, R. (1975), "Residential Demand for Electric Energy," Review of Economics and Statistics, 57 (February), pp. 12-18.

41. Hirst, E., W. Lin, and J. Cope (1976), "An Engineering-Economic Model of Residential Energy Use," Technical Report No. TM-5470, Oak Ridge National Laboratory, Tenn., July.

42. Hnyilicza, E., and R.S. Pindyck (1976), "Pricing Policies for the Two-Part Exhaustible Resource Cartel: The Case of OPEC," European Economic Review, Vol. 8, pp. 139-147.

43. Hoffman, L. (1978), "Energy Demand in Developing Countries: Approaches to Estimation and Projection," in Workshop on Energy Data of Developing Countries, Vol. 1 (Paris: IEA/OECD).

44. Hoffmann, L., and M. Mors (1981), "Energy Demand in the Developing World: Estimation and Projections to 1990 by Region and Country," in World Bank Commodity Models, Vol. 1, World Bank Staff Commodity Working Paper No. 6, Washington, D.C.

45. Hotelling, H. (1931), "The Economics of Exhaustible Resources," Journal of Political Economy, April, pp. 137-175.

46. Houthakker, H.S., and P. Verleger (1973), "The Demand for Gasoline: A Mixed Cross-Sectional and Time Series Analysis," unpublished paper, Data Resources, Inc., Lexington, Mass.

47. Houthakker, H.S., P.K. Verleger, and D.P. Sheehan (1974), "Dynamic Demand Analyses for Gasoline and Residential Electricity, American Journal of Agricultural Economics, Vol. 56, May.

48. Hudson, E.A., and D.W. Jorgenson (1974), "U.S. Energy Policy and Economic Growth, 1975-2000," The Bell Journal of Economics and Management Science, 5 (Autumn), pp. 461-514.

49. Humphrey, D.B., and J.R. Moroney (1975), "Substitution Among Capital, Labor and Natural Resource Products in American Manufacturing," Journal of Political Economy, 83 (February), pp. 57-82.

50. ICF Inc. (1980), "The Coal Supply Cost Function," Coal and Electric Utilities Model: Analysis and Evaluation, Vol. 4, MIT Energy Laboratory Report No. MIT-EL81-015, Cambridge, Mass.

51. International Energy Agency (1978), Steam Coal: Prospects to 2000 (Paris: IEA/OECD).

52. International Energy Agency (1979), Workshop on Energy Data of Developing Countries, Vol. 2 (Paris: IEA/OECD).

53. International Energy Agency (1982a), World Energy Outlook (Paris: IEA/OECD).

54. International Energy Agency (1982b), Coal Prospects and Policies in IEA Countries: 1981 Review (Paris: IEA/OECD).

55. International Energy Agency (1982c), Energy Balances of OECD Countries (Paris: IEA/OECD).

56. International Energy Agency (1982d), Energy Statistics (Paris: IEA/OECD).

57. Jankowski, J.E. (1981), "Industrial Energy Demand and Conservation in Developing Countries," Discussion Paper D-73A, Resources for the Future, Washington, D.C.

58. Joskow, P.L., and M.L. Baughman (1976), "The Future of the U.S. Nuclear Energy Industry," The Bell Journal of Economics, 7 (Spring), pp. 3-32.

59. Kalymon, B.A. (1975), "Economic Incentives in OPEC Oil Pricing Policy," Journal of Developing Economics, Vol. 2, No. 4, pp. 337-362.

60. Kennedy, M. (1974), "An Economic Model of the World Oil Market," The Journal of Economics and Management Science, Vol. 5, No. 2, pp. 540-577.

61. Koopmans, Tjalling (1973), "Some Observations on 'Optimal' Economic Growth and Exhaustible Resources," in H.C. Bos, H. Linneman, and P. de Wolff eds. Economic Structure and Development: Essays in Honour of Jan Tinbergen, (Amsterdam: North-Holland), pp. 239-255.

62. Koopmans, T., P. Diamond, and R. Williamson (1964), "Stationary Utility and Time Perspective," Econometrica, 32, pp. 82-100.

63. Kuenne, R.E. (1978), "General Oligopolistic Equilibrium: Crippled Optimization Approach," in T. Bagiotti and G. Franco eds. Pioneering Economics (Padua: Edizioni Cedam).

64. Kuenne, R.E. (1979), "Measuring the Power Structure of Oligopoly: The Case of OPEC," OPEC Cartel Modeling Project, Research Monograph No. 2, General Economic Systems Project, Princeton University, Princeton, New Jersey.

65. Latin American Energy Organization (1981), Energy Balances For Latin America (Quito, Ecuador: OLADE).

66. McGillivray, R.G. (1976), "Gasoline Use by Automobiles," in Transportation Energy Conservation and Demand (Washington, D.C: National Academy of Sciences, National Research Council), pp. 45-56.

67. McGraw-Hill, Keyston Coal Industry Manual, various issues (New York: McGraw Hill).

68. Magnus, J.R., "Substitution Between Energy and Non-Energy Inputs in The Netherlands: 1950-1974," International Economic Review (forthcoming).

69. Mount, T.D., L.D. Chapman, and T.J. Tyrrell (1973), "Electricity Demand in the United States: An Econometric Analysis," Report ORNL-NSF-EP-49, Oak Ridge National Laboratory, Oak Ridge, Tenn.

70. Nordhaus, W.D., (1973), "The Allocation of Energy Resources," Brookings Papers on Economic Activity, Brookings Institution, Washington, D.C. pp. 529-70.

71. Nordhaus, W.D., (1979), The Efficient Use of Energy Resources, Cowles Foundation Monograph 26 (New Haven: Yale University Press).

72. Olliver, R.B. (1982), "Steam Coal in Southern Africa," EIU Special Report No. 122, Economist Intelligence Unit, London, April.

73. Pindyck, R.S. (1975), "A Dynamic Model of OPEC Trade and Production," Journal of Development Economics, pp. 319-335.

74. Pindyck, R.S. (1978), "Gains to Producers from Cartelization of Exhaustible Resources," Review of Economics and Statistics, Vol. 60, No. 2 (May), pp. 238-251.

75. Pindyck, R.S. (1979), The Structure of World Energy Demand, (Cambridge, Massachusetts: The MIT Press).

76. Ramsey, J., R. Rasche, and B. Allen (1975), "An Analysis of the Private and Commercial Demand for Gasoline," Review of Economics and Statistics, 57 (November), pp. 502-507.

77. Robinson, C., and E. Marshall (1981), What Future for British Coal? (London: The Institute of Economic Affairs).

78. Rodseth, A., and S. Strom (1976), "The Demand for Energy in Norwegian Households with Special Emphasis on the Demand for Electricity," Research Memorandum, Institute of Economics, University of Oslo, April.

79. Solow, R.M. (1974a), "The Economics of Resources or the Resources of Economics," American Economic Review, (May), pp. 1-14.

80. Solow, R.M. (1974b), "Intergenerational Equity and Exhaustible Resources," Review of Economic Studies, Symposium on the Economics of Exhaustible Resources, pp. 29-45.

81. Solow, R.M., and F.Y. Wan (1976), "Extraction Costs in the Theory of Exhaustible Resources," Bell Journal of Economics, Vol. 7(2), pp. 359-70.

82. Stiglitz, J.E. (1976), "Monopoly and the Rate of Extraction of Exhaustible Resources," American Economic Review, (September), pp. 655-661.

83. Sweeney, J.L. (1978), "The Demand for Gasoline in the United States: A Vintage Capital Model," in Workshops on Energy Supply and Demand (Paris: IEA/OECD), pp. 240-277.

84. United Nations, World Energy Supplies, various issues (New York: United Nations).

85. Uri, N.D. (1979), "Energy Demand and Interfuel Substitution in India," European Economic Review, pp. 181-190.

86. World Energy Conference (1978), World Energy Resources 1985-2000, IPC Science and Technology Press.

87. Zimmerman, Martin B. (1981), The U.S. Coal Industry: The Economics of Policy Choice (Cambridge, Mass.: The MIT Press).

World Bank Publications of Related Interest

Alcohol Production from Biomass in the Developing Countries

Explains the techniques for manufacturing ethyl alcohol from biomass raw materials; analyzes the economics of and prospects for production and government policies needed to accommodate conflicting needs of various sectors of the economy in promoting production; and discusses the role the World Bank can play in assisting developing countries in designing national alcohol programs. (One of three publications dealing with renewable energy resources in developing countries. See *Mobilizing Renewable Energy Technology in Developing Countries: Strengthening Local Capabilities and Research* and *Renewable Energy Resources in the Developing Countries.*)

September 1980. ix + 69 pages (including 12 annex figures). English, French, Spanish, and Portuguese.

Stock Nos. EN-8002-E, EN-8002-F, EN-8002-S, EN-8002-P. $5.00.

The Economic Choice between Hydroelectric and Thermal Power Developments

Herman G. van der Tak

A logically correct method for handling the economic comparison of alternative systems.

The Johns Hopkins University Press, 1966; 4th printing, 1974. 80 pages (including 2 appendixes).

LC 66-28053. ISBN 0-8018-0646-1, $5.00 (£3.00) paperback.

The Economics of Power System Reliability and Planning: Theory and Case Studies

Mohan Munasinghe

A completely integrated treatment of system reliability. Indicates that application of the reliability optimization methodology could help realize considerable savings in the electric power sector, which is especially important for developing countries with limited foreign exchange reserves.

The Johns Hopkins University Press, 1980. 344 pages (including tables, maps, index).

LC 79-2182. ISBN 0-8018-2276-9, $27.50 (£16.75) hardcover; ISBN 0-8018-2277-7, $12.50 (£6.25) paperback.

NEW

The Effect of Discount Rate and Substitute Technology on Depletion of Exhaustible Resources

Yeganeh Hossein Farzin

The succession of sharp price increases of oil in the early 1970s raised several issues related to competition against OPEC as a supplier of oil and competition against oil as a form of energy. This paper considers the latter form of competition and develops a model to analyze the validity of some basic propositions in the economics of exhaustible resources in the presence of substitutes.

World Bank Staff Working Paper No. 516. 1982. 51 pages (including references).

ISBN 0-8213-0004-0. $3.00.

Electricity Economics: Essays and Case Studies

Ralph Turvey and Dennis Anderson

Argues the merits of relating the price of electricity to the marginal or incremental cost of supply and deals with interactions between pricing and investment decisions, income distribution, and distortions in the pricing system of the economy.

The Johns Hopkins University Press, 1977; 2nd printing, 1981. 382 pages (including tables, maps, index).

LC 76-9031. ISBN 0-8018-1866-4, $30.00 (£13.50) hardcover; ISBN 0-8018-1867-2, $12.95 (£5.75) paperback.

French: L'économie de l'électricité: essais et études de cas. *Economica, 1979.*

ISBN 2-7178-0165-0, 58 francs.

Spanish: Electricidad y economía: ensayos y estudios de casos. *Editorial Tecnos, 1979.*

ISBN 84-309-0822-6, 710 pesetas.

Electricity Pricing: Theory and Case Studies

Mohan Munasinghe and Jeremy J. Warford

Describes the underlying theory and practical application of power-pricing policies that maximize the net economic benefits to society of electricity consumption. The methodology provides an explicit framework for analyzing system costs and setting tariffs, and it allows the tariff to be revised on a continual basis. Case studies of electricity pricing exercises in Indonesia, Pakistan, the Philippines, Sri Lanka, and Thailand describe the application of the methodology to real systems.

The Johns Hopkins University Press. 1982. 399 pages (including appendixes, index).

LC 81-47613. ISBN 0-8018-2703-5, $29.50 hardcover.

NEW

Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries

Methanol, or methyl alcohol, is among the major basic chemical raw materials produced today. This report reviews the major chemical and, particularly, fuel applications of methanol as a basis for projecting the minimal methanol market size during the 1980s and it concludes that there

is a significant potential for additional methanol capacity in developing countries that possess low-cost gas resources, yet, in most cases, do not have an adequate supply of oil. Complements the World Bank report, *Alcohol Production from Biomass in the Developing Countries* (September 1980).

April 1982. viii + 73 pages.

ISBN 0-8213-0018-0. $5.00.

Energy in the Developing Countries

Discusses the energy problem of the 1970s and the perspective for the next decade. States that by tapping reserves of oil, gas, coal, and hydroelectric and forest resources previously considered uneconomical and by vigorous conservation efforts, oil-importing countries could halve their oil-import bill by 1990. Outlines measures for saving energy without reducing economic growth and exhorts industrialized and industrializing countries to adjust energy prices, incentives, and investments to emphasize domestic production. Proposes a World Bank program for energy lending and explains the operational aspects of the program.

August 1980. vi + 92 pages (including 5 annexes).

Stock No. EN-8001. Free of charge.

Energy Options and Policy Issues in Developing Countries

Darrel G. Fallen-Bailey and Trevor A. Byer

World Bank Staff Working Paper No. 350. August 1979. vi + 107 pages.

Stock No. WP-0350. $5.00.

Global Energy Prospects

Boum Jong Choe, Adrian Lambertini, and Peter K. Pollak

A background study for *World Development Report, 1981.* Examines adjustments in the use of energy that have taken place in five major country groups since the 1973–74 oil price increase. Based on these trends, energy conservation and efficiency, and assumptions about income levels and of a 3 percent annual increase in real energy prices, the paper provides energy projections by major fuels for these country groups in the 1980s.

World Bank Staff Working Paper No. 489. August 1981. viii + 63 pages.

Stock No. WP-0489. $3.00.

India: The Energy Sector

P. D. Henderson

Summary review of the sector, providing technical, historical, and statistical background information.

Oxford University Press, 1975. 210 pages (including map, 2 appendixes, index).

ISBN 0-19-560653-1, $12.95 (£3.25; Rs30) hardcover.

Mobilizing Renewable Energy Technology in Developing Countries: Strengthening Local Capabilities and Research

Focuses on the research required to develop renewable energy resources in the developing countries and on the need to strengthen the developing countries' own technological capabilities for using renewable energy. (One of three publications dealing with renewable energy resources and issues in developing countries. See *Alcohol Production from Biomass in the Developing Countries* and *Renewable Energy Resources in the Developing Countries.*)

July 1981. iv + 52 pages.

Stock No. EN-8101. $5.00.

Renewable Energy Resources in the Developing Countries

Examines the contributions that renewable resources can make to energy supplies in developing countries and discusses the role of the World Bank in renewable energy development over the next five years. (One of three publications dealing with renewable energy resources and issues in developing countries. See *Alcohol Production from Biomass in the Developing Countries* and *Mobilizing Renewable Energy Technology in Developing Countries: Strengthening Local Capabilities and Research.*)

November 1980. iv + 33 pages (including annex).

Stock No. EN-8003. $5.00.

Rural Electrification

Discusses the prospects for successful investment in rural electrification and considers implications for World Bank policies and procedures.

A World Bank Paper. October 1975. 80 pages (including annex). English, French, and Spanish.

Stock Nos. PP-7505-E, PP-7505-F, PP-7505-S. $5.00.

The Energy Transition in Developing Countries, just published, details why the Bank intends to commit one fourth of its loan funds to support energy projects through 1987.

This valuable analysis updates the 1980 *Energy in the Developing Countries*, the last comprehensive World Bank report on the subject. Since then the Bank has provided needed energy assistance in developing countries by expanding and diversifying its energy activities. The insights gained from projects the Bank has financed form the basis for the penetrating analysis in this new report. Those who use the report will profit from the diverse experience of energy specialists who have been actively involved in field operations.

REPRINTS

Absorptive Capacity, the Demand for Revenue, and the Supply of Petroleum
Salah El Serafy

World Bank Reprint Series: Number 213. Reprinted from The Journal of Energy and Development, *vol. 7, no. 1 (Autumn 1981): 73-88.*

Stock No. RP-0213. Free of charge.

Environmental Ranking of Amazonian Development Projects in Brazil
Robert Goodland

World Bank Reprint Series: Number 198. Reprinted from Environmental Conservation, *vol. 7, no. 1 (Spring 1980):9-26.*

Stock No. RP-0198. Free of charge.

Optimal Electricity Supply: Reliability, Pricing, and System Planning
Mohan Munasinghe

World Bank Reprint Series: Number 201. Reprinted from Energy Economics, *vol. 3, no. 3 (July 1981):140-52.*

Stock No. RP-0201. Free of charge.

WORLD BANK PUBLICATIONS
ORDER FORM

SEND TO:

WORLD BANK PUBLICATIONS
P.O. BOX 37525
WASHINGTON, D.C. 20013
U.S.A.

or

WORLD BANK PUBLICATIONS
66, AVENUE D'IÉNA
75116 PARIS, FRANCE

Name: _____

Address: _____

_____

Stock or ISBN #	Author, Title	Qty.	Price	Total

Sub-Total Cost: _____

Postage & handling fee for more than two free items ($1.00 each): _____

Total copies: _____ Air mail surcharge ($2.00 each): _____

TOTAL PAYMENT ENCLOSED: _____

Make checks payable: WORLD BANK PUBLICATIONS

Prepayment on orders from individuals is requested. Purchase orders are accepted from booksellers, library suppliers, libraries, and institutions. All prices include cost of postage by the least expensive means. The prices and publication dates quoted in this Catalog are subject to change without notice.

No refunds will be given for items that cannot be filled. Credit will be applied towards future orders.

No more than two free publications will be provided without charge. Requests for additional copies will be filled at a charge of US $1.00 per copy to cover handling and postage costs.

Airmail delivery will require a prepayment of US $2.00 per copy.

Mail-order payment to the World Bank need not be in U.S. dollars, but the amount remitted must be at the rate of exchange on the day the order is placed. The World Bank will also accept Unesco coupons.

The World Bank

Headquarters
1818 H Street, N W
Washington, D.C. 20433, U.S.A.
Telephone. (202) 477-1234
Telex· WUI 64145 WORLDBANK
RCA 248423 WORLDBK
Cable Address. INTBAFRAD
WASHINGTONDC

European Office
66, avenue d'Iéna
75116 Paris, France
Telephone (1) 723-54.21
Telex. 842-620628

Tokyo Office
Kokusai Building
1-1 Marunouchi 3-chome
Chiyoda-ku, Tokyo 100, Japan
Telephone: (03) 214-5001
Telex 781-26838

ISSN 0253-2115/ISBN 0-8213-0328-7